TRANSALTA CORPORATION Management's Discussion and Analysis

First 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 months ended March 31, 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 March 31, 2024. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted, except amounts per share, which are in whole dollars to the nearest two decimals. This MD&A is dated May 2, 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 the 2024 Outlook, including Adjusted EBITDA, free cash flow, annualized dividends per share, sustaining capital spending, and energy marketing gross margin; the Company's expanded 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 anticipated benefits arising from the MOU (as defined below) with the Government of Alberta; the Company's investment strategy to deliver long-term value to shareholders; the common share dividend level through 2024; the Company's projects under construction, including capital costs, the timing of commercial operations and expected annual EBITDA, including the Horizon Hill wind development; the impact of new asset additions in 2024 including Kent Hills, Mount Keith transmission, and White Rock; the development of the early-stage and advanced-stage projects; achieving the anticipated benefits of 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; the Company's ability to achieve its long-term decarbonization goal to be net zero by 2045; the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the expected impact and quantum of carbon compliance costs; the retirement of Centralia Unit 2 at the end of 2025; regulatory developments and their expected impact on the Company; expectations regarding the refinancing of debt; recognition by the Company of natural gas transportation agreements as onerous in the case the Company decides to retire certain facilities in advance of the expiry date of the natural gas transportation agreements; and the Company continuing to maintain adequate liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations 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 use of our assets; 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 credit risk and any higher rate of losses on our accounts receivables; inability to achieve our environmental, social and governance ("ESG") targets; 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 contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate, including the impacts of restrictions on renewable energy projects, amended Independent System Operator rules, expected changes to Transmission Regulations, and the creation of the Restructured Energy Market (defined below); 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 now has over 112 years of operating experience in the development, production and sale of electricity. We own, operate and manage a geographically diversified portfolio of generation assets that includes water, wind, solar, battery storage, natural gas and transition coal. We are one of the largest producers of wind power 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 provides 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 highly diversified portfolio consists of both high-quality contracted assets and merchant assets. Approximately 57 per cent of our total installed capacity is contracted with investment-grade or creditworthy counterparties. 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 52 per cent of our capacity is located and 75 per cent of our Alberta capacity is available to participate in the merchant electricity market.

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 commercial and industrial customers and is supplemented with financial hedges. Refer to the 2024 Outlook and the Optimization of the Alberta Portfolio sections of this MD&A for further details.

Our diversified fleet is a key success factor in our ability to deliver resilient cash flows while capturing higher risk-adjusted returns for our shareholders.

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 achieved commercial operation. The Mount Keith 132kV expansion project was also completed during the first quarter of 2024.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of March 31, 2024:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
As at March 31, 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	—	—	619	8	29	1	671	2	1,319	11
Australia	—	—	48	3	450	6	—	—	498	9
Total	**922**	**24**	**2,184**	**34**	**3,087**	**17**	**671**	**2**	**6,864**	**77**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for the Wind and Solar segment includes 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 Unit 1 and the Skookumchuck Hydro facility.

Stable and Predictable Cash Flows

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 March 31, 2024:

As at March 31, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta	—	374	511	—	885
Canada, excluding Alberta	88	751	645	—	1,484
US	—	619	29	381	1,029
Australia	—	48	450	—	498
Total contracted capacity (MW)	88	1,792	1,635	381	3,896
Contracted capacity as a % of total capacity (%)	10%	82%	53%	57%	57%

The weighted average contract life (years) of our facilities across the regions in which we operate as of March 31, 2024 is:

As at March 31, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta(1)(2)	—	16	7	—	11
Canada, excluding Alberta(2)	10	10	8	—	9
US(2)	—	11	2	2	7
Australia(2)	—	15	15	—	15
Total weighted contract life (years)(2)	10	12	9	2	10

(1) The weighted-average remaining contract life in the Wind and Solar segment is related to the contract period for Garden Plain (130 MW), McBride Lake (38 MW), and Windrise (206 MW). The weighted-average remaining contract life in the Gas segment is related to the contract period for Poplar Creek (230 MW), Fort Saskatchewan (71 MW) and a capacity-contract that is not directly contracted with any one facility (210 MW).

(2) For power generated under long-term power purchase agreements ("PPAs") and other long-term contracts, the weighted-average remaining contract life is based on long-term average gross installed capacity.

The majority of TransAlta's long-term power purchase agreements are with investment-grade rated or creditworthy counterparties. Additionally, our financial hedging strategy including maintaining a significant base of commercial and industrial customers in Alberta further supports the delivery of stable and predictable cash flows.

Highlights

For the three months ended March 31, 2024, the Company demonstrated strong financial and operational performance and is on track to meet its 2024 Outlook, due to active management of our merchant portfolio and hedging strategies, which included higher production in the Hydro and Gas segments.

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2024**	**2023**
Operational information		
Adjusted availability (%)	**92.3**	92.0
Production (GWh)	**6,178**	5,972
Select financial information		
Revenues	**947**	1,089
Earnings before income taxes	**267**	383
Adjusted EBITDA(1)	**328**	503
Net earnings attributable to common shareholders	**222**	294
Cash flows		
Cash flow from operating activities	**244**	462
Funds from operations(1)	**239**	374
Free cash flow(1)	**206**	263
Per share		
Weighted average number of common shares outstanding	**308**	268
Net earnings per share attributable to common shareholders, basic and diluted	**0.72**	1.10
Funds from operations per share(1)(2)	**0.78**	1.40
Free cash flow per share(1)(2)	**0.67**	0.98

As at	March 31, 2024	Dec. 31, 2023
Liquidity and capital resources		
Available liquidity	**1,737**	1,738
Adjusted net debt to adjusted EBITDA(1) (times)	**2.8**	2.5
Total consolidated net debt(1)(3)	**3,384**	3,453
Assets and liabilities		
Total assets	**8,752**	8,659
Total long-term liabilities	**4,487**	5,253
Total liabilities	**6,820**	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 March 31	2024	2023
Hydro	**91.9**	94.1
Wind and Solar	**93.4**	82.9
Gas	**94.6**	96.4
Energy Transition	**79.0**	94.5
Adjusted availability (%)	**92.3**	92.0

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. 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 months ended March 31, 2024, was 92.3 per cent, compared to 92.0 per cent in the same period in 2023.

Higher adjusted availability was primarily due to:

- The return to service of the Kent Hills wind facilities; and
- Lower unplanned outages in the Wind and Solar segment; partially offset by,
- Unplanned outages at Centralia Unit 2 in the Energy Transition segment;
- Unplanned outages at Sundance Unit 6 and the Australia gas facilities in the Gas segment; and,
- Planned major maintenance outages in the Hydro segment.

Production and Long-Term Average Generation

	2024			2023		
As at March 31	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	**351**	**402**	**87 %**	306	402	76%
Wind and Solar	**1,498**	**1,644**	**91 %**	1,197	1,423	84%
Gas	**3,528**			3,172		
Energy Transition	**801**			1,297		
Total	**6,178**			5,972		

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 in line 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 model based on historical resource data performed over a period of typically greater than 25 years.

LTA generation for Energy Transition is not considered as we are currently transitioning these units with the expectation that the final unit will retire by the end of 2025. The LTA generation for Gas 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 months ended March 31, 2024, increased by 206 GWh or 3 per cent compared with the same period in 2023.

Production from our renewables assets for the three months ended March 31, 2024, was higher by 346 GWh, or 23 per cent compared to 2023, yielding 90 per cent of LTA generation.

The Wind and Solar production increased by 301 GWh, or 25 per cent, driven primarily by

- Production from new facilities, including the White Rock West wind facility commissioned in January 2024 and the Garden Plain wind facility commissioned in August 2023;
- The return to service of the Kent Hills wind facilities, completed in the first quarter of 2024;
- Pre-commissioning production from the White Rock East wind facility and the Horizon Hill wind project; partially offset by
- Lower wind resource in Alberta.

Hydro production increased by 45 GWh, or 15 per cent, yielding 87 per cent of LTA generation. Higher energy production at Hydro during the quarter was in response to significant demand resulting from periods of extreme cold conditions in Alberta.

The Gas segment production increased by 356 GWh or 11 per cent. The higher production from the segment was primarily driven by the Sarnia facility as market conditions were favourable which enabled higher dispatch and resulted in higher merchant production to the Ontario grid.

Production from the Energy Transition segment was negatively impacted by higher unplanned outage hours and increased economic dispatch at the Centralia facility compared to the prior period.

Market Pricing

3 months ended March 31	2024	2023
Alberta spot power price ($/MWh)	**99**	142
Mid-Columbia spot power price (US$/MWh)	**104**	106
Ontario spot power price ($/MWh)	**33**	27
Natural gas price (AECO) per GJ ($)	**1.94**	3.08

For the three months ended March 31, 2024, spot electricity prices in Alberta were on average lower compared with the same period in 2023, driven by milder weather conditions and the additions of new natural gas, wind and solar supply in the market.

Spot electricity prices in the Pacific Northwest were comparable on average to the same period in 2023 however, this was due to high prices concentrated in January this quarter.

AECO natural gas prices for the three months ended March 31, 2024, were lower compared with the same period in 2023, mainly due to improved production and higher storage levels in Alberta and throughout North America.

Financial Performance review on Consolidated Information

3 months ended March 31	2024	2023
Revenues	**947**	1,089
Fuel and purchased power	**323**	325
Carbon compliance	**40**	32
Operations, maintenance and administration	**134**	124
Depreciation and amortization	**124**	176
Earnings before income taxes	**267**	383
Income tax expense	**29**	49
Net earnings attributable to common shareholders	**222**	294
Net earnings attributable to non-controlling interests	**16**	40

First Quarter Variance Analysis (2024 versus 2023)

Revenues totalling $947 million, decreased by $142 million, or 13 per cent, compared to the same period in 2023, primarily due to:

- Lower revenue from merchant sales in Alberta due to lower spot and hedged power prices;
- Lower production at Centralia in the Energy Transition segment; and
- Lower realized and unrealized gains from hedging and derivative positions in the Energy Marketing segment.

Fuel and purchased power costs totalling $323 million, decreased by $2 million, or 1 per cent, compared to the same period in 2023, primarily due to:

- Lower production in the Energy Transition segment; and
- Lower natural gas commodity pricing; partially offset by
- Higher production in the Gas segment.

Carbon compliance costs totalling $40 million, increased by $8 million, or 25 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; and
- Higher production in the Gas segment.

Operations, maintenance and administration ("OM&A") expenses totalling $134 million, increased by $10 million, or 8 per cent, compared to the same period in 2023, primarily due to:

- Higher spending on strategic and growth initiatives; and
- Higher OM&A from the addition of the Garden Plain and White Rock West wind facilities and the Northern Goldfields solar facilities.

Depreciation and amortization totalling $124 million, decreased by $52 million, or 30 per cent, compared to the same period in 2023, primarily due to revisions to useful lives on certain facilities in prior periods.

Earnings before income taxes totalling $267 million, decreased by $116 million, or 30 per cent, compared to the same period in 2023, due to the above noted items.

Income tax expense totalling $29 million, decreased by $20 million, or 41 per cent, compared to the same period in 2023, due to lower earnings before income taxes and lower US non-deductible expenses relating to the US operations.

Net earnings attributable to non-controlling interests totalling $16 million, decreased by $24 million, or 60 per cent, compared to the same period in 2023, primarily due to lower net earnings for TransAlta Cogeneration, LP ("TA Cogen") and no net earnings attributable to non-controlling interests for TransAlta Renewables Inc. ("TransAlta Renewables") in the first quarter of 2024.

Adjusted EBITDA

For the three months ended March 31, 2024, the Company's adjusted EBITDA was $328 million as compared to $503 million in 2023, a decrease of $175 million. The major factors impacting adjusted EBITDA are summarized in the following table:

	3 months ended March 31
Adjusted EBITDA for the three months ended March 31, 2023	503
Hydro: lower primarily due to lower realized gains on forward contracts compared to the prior period and lower realized power and ancillary services prices in the Alberta market, partially offset by higher production and higher environmental attribute revenues.	(19)
Wind and Solar: higher primarily due to higher environmental attribute revenues, the return to service of the Kent Hills wind facilities, the commercial operation of the Garden Plain wind facility, White Rock West wind facility and Northern Goldfields solar facilities, offset by lower realized power pricing in the Alberta market, weaker wind resource across the Alberta operating fleet and higher OM&A due to the addition of the new wind and solar facilities.	1
Gas: lower primarily due to lower realized power and ancillary services prices in Alberta, lower capacity payments for Southern Cross Energy due to the conclusion of the demand capacity charge under the applicable customer contract, higher carbon costs and higher OM&A, partially offset by the commencement of capacity payments for the Mount Keith 132kV expansion and lower natural gas commodity costs.	(106)
Energy Transition: lower primarily due to lower production from higher unplanned outages and increased economic dispatch due to lower market prices, partially offset by lower fuel and purchased power costs.	(28)
Energy Marketing: lower primarily due to lower realized settled trades during the period on market positions in comparison to the prior period, partially offset by lower OM&A due to lower incentives.	(19)
Corporate: lower primarily due to increased spending to support strategic and growth initiatives.	(4)
Adjusted EBITDA(1) for the three months ended March 31, 2024	**328**

(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 months ended March 31, 2024, the Company's FCF decreased by $57 million, or 22 per cent, compared with the same period in 2023. The major factors impacting FCF are summarized in the following table:

	3 months ended March 31
FCF for the three months ended March 31, 2023	263
Lower adjusted EBITDA: due to the items noted above.	(175)
Lower current income tax expense due to lower earnings before tax.	33
Lower sustaining capital expenditures: expenditures were offset by the receipt of a lease incentive related to the relocation of the Company's head office.	21
Lower distributions paid to subsidiaries' non-controlling interests: relating to the timing of distributions paid to TA Cogen and the cessation of distributions by TransAlta Renewables Inc.	57
Other non-cash items[1]	14
Other[2]	(7)
FCF[3] for the three months ended March 31, 2024	**206**

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

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

(3) FCF is not defined and has no standardized meaning under IFRS. 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.

3 months ended March 31	2024	2023
Hydro	3	6
Wind and Solar	2	3
Gas	3	3
Corporate	(9)	8
Total sustaining capital expenditures	**(1)**	20

Total sustaining capital expenditures in 2024 were $21 million lower compared with the same period 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 Hydro Assets.

3 months ended March 31	2024	2023
Hydro	2	—
Wind and Solar	41	255
Gas	3	—
Corporate[1]	9	15
Growth and development expenditures	**55**	270

(1) Expenditures related to projects in the development phase are included in the Corporate segment.

In the first quarter of 2024, growth and development expenditures were lower compared with the same period in 2023, primarily due to the White Rock East and Horizon Hill wind projects being in their final stages of construction. The White Rock West wind facility and Mount Keith 132kV expansion were commissioned and completed in the first quarter of 2024. In addition to these projects, 2023 growth and development expenditures also included the Garden Plain wind facility, which commissioned in August 2023, and the Northern Goldfields solar facilities, which commissioned in November 2023. Refer to the Strategic Priorities and Clean Electricity Growth Plan to 2028 section of this MD&A for more details.

Significant and Subsequent Events

White Rock Wind Facilities Achieve Commercial Operation

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation. On April 22, 2024, the 200 MW White Rock East wind facility was also commissioned. The White Rock wind 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. The Company's wind generating portfolio in the US now totals 819 MW in gross installed capacity.

Annual Shareholder Meeting

The Honourable Rona Ambrose did not stand for reelection and retired from the Board following the annual shareholder meeting on April 25, 2024. The Board extends its gratitude for her service to the Company. She has been a valuable contributor to the Board since 2017 and we thank her for her leadership and insight, including her contributions as Chair of the Governance, Safety and Sustainability Committee of the Board.

At the annual general meeting of the holders of common shares of TransAlta, the Company received strong support on all items of business, including the election of 12 directors, re-appointment of auditors and Say-on-Pay.

Bow River Basin Memorandum of Understanding

On April 19, 2024, the Company announced it had signed a voluntary water-sharing memorandum of understanding with over thirty other water licence holders in the Bow River Basin. The Government of Alberta continues to anticipate and prepare for lower water conditions this summer with specific concerns in southern Alberta where agriculture could be impacted by water shortages. The Government of Alberta is leading efforts to coordinate water usage among water licence holders for Alberta river basins in an effort to ensure licensees get the water they need as opposed to the water to which they are entitled. In recognition of the unique role the Company plays in managing water flows while also serving as a key provider to Alberta's electricity grid, we look forward to working with the Government and downstream stakeholders to maximize water storage in the early season to help mitigate any anticipated drought conditions. We anticipate the Company's water management efforts will not have an adverse impact on our electricity generating and environmental objectives.

TransAlta Announced Retirement of CFO and Appointment of New CFO

On April 11, 2024, the Company announced the retirement of Todd Stack, Executive Vice President, Finance and Chief Financial Officer from the Company, effective June 30, 2024. The Board of Directors ("the Board") expresses its deep appreciation to Todd for his contributions to TransAlta and its success during his 34-year career with the Company.

The Board has appointed Joel E. Hunter as Executive Vice President, Finance and Chief Financial Officer, 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. The Company previously announced an enhanced common share repurchase program for 2024 of up to $150 million, targeting up to 42 per cent of 2024 FCF guidance being returned to shareholders in the form of share repurchases and dividends.

The Company also previously announced that it had received approval from the Toronto Stock Exchange ("TSX") to purchase up to 14,000,000 of its common shares during the 12-month period that commenced on May 31, 2023 and will terminate on May 30, 2024. The Company intends to renew the NCIB in May 2024.

On March 19, 2024, the Company entered into an ASPP to facilitate repurchases of TransAlta's common shares under its NCIB.

Under the ASPP, the Company's broker may purchase common shares from the effective date of the ASPP until the termination of the ASPP. All purchases of common shares made under the ASPP will be included in determining the number of common shares purchased under the NCIB. The ASPP will terminate on the earliest of the date on which: (a) the maximum purchase limits under the ASPP are reached; (b) May 3, 2024; or (c) the Company terminates the ASPP in accordance with its terms.

During the three months ended March 31, 2024, the Company purchased and cancelled a total of 3,460,300 common shares, at an average price of $9.36 per common share, for a total cost of $32 million.

Mount Keith 132kV Expansion Complete

The Mount Keith 132kV expansion project was completed during the first quarter of 2024. The expansion was developed under the existing PPA with BHP Nickel West ("BHP"), which has 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.

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 projects. The expected annual average EBITDA from these contracts is approximately $57 million (US$43 million).

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. The following table reflects the summary financial information on a consolidated basis for the three months ended March 31:

	Adjusted EBITDA(1)	
3 months ended March 31	**2024**	**2023**
Hydro	**87**	106
Wind and Solar	**89**	88
Gas	**134**	240
Energy Transition	**26**	54
Energy Marketing	**20**	39
Corporate	**(28)**	(24)
Total adjusted EBITDA(1)	**328**	503
Earnings before income taxes	**267**	383

(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.

Hydro

3 months ended March 31	2024	2023	Change	
Gross installed capacity (MW)	922	922	—	— %
LTA generation (GWh)	402	402	—	— %
Availability (%)	91.9	94.1	(2.2)	(2)%
Production				
Contract production (GWh)	38	23	15	65 %
Merchant production (GWh)	313	283	30	11 %
Total energy production (GWh)	351	306	45	15 %
Ancillary service volumes (GWh)(1)	661	643	18	3 %
Alberta Hydro Assets revenues(2)(3)	49	71	(22)	(31)%
Other Hydro Assets and other revenues(2)(4)	8	6	2	33 %
Alberta Hydro ancillary services revenues(1)	36	39	(3)	(8)%
Environmental attribute revenues	14	8	6	75 %
Revenues(5)	107	124	(17)	(14)%
Fuel and purchased power	6	5	1	20 %
Gross margin(6)	101	119	(18)	(15)%
OM&A	13	12	1	8 %
Taxes, other than income taxes	1	1	—	— %
Adjusted EBITDA(6)	87	106	(19)	(18)%
Supplemental Information:				
Gross revenues per MWh				
Alberta Hydro Assets energy ($/MWh)(2)(3)	152	258	(106)	(41)%
Alberta Hydro Assets ancillary ($/MWh)(1)	54	60	(6)	(10)%

(1) Ancillary services as described in the Alberta Electric System Operator ("AESO") Consolidated Authoritative Document Glossary.

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

(3) The Company entered into forward hedges for the first quarter of 2023 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 months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower realized power and ancillary prices in the Alberta market; and
- Lower realized gains on forward contracts compared to the prior period when the Company captured revenue through forward hedging for the Alberta Hydro Assets and realized gains from the hedging strategy in the first quarter of 2023; partially offset by
- Higher production due to significant demand in periods of extreme cold temperature conditions in Alberta; and
- Higher sales of environmental attributes to third parties.

Adjusted EBITDA for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to lower revenues as explained by the factors above.

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

Wind and Solar

3 months ended March 31	2024	2023	Change	
Gross installed capacity (MW)[1]	**2,184**	**1,906**	*278*	*15 %*
LTA generation (GWh)	**1,644**	**1,423**	*221*	*16 %*
Availability (%)	**93.4**	**82.9**	*10.5*	*13 %*
Production				
Contract production (GWh)	**1,154**	**871**	*283*	*32 %*
Merchant production (GWh)	**344**	**326**	*18*	*6 %*
Total production (GWh)	**1,498**	**1,197**	*301*	*25 %*
Wind and Solar revenues	**102**	**102**	*—*	*— %*
Environmental attribute revenues	**18**	**13**	*5*	*38 %*
Revenues[2]	**120**	**115**	*5*	*4 %*
Fuel and purchased power	**9**	**9**	*—*	*— %*
Gross margin[3]	**111**	**106**	*5*	*5 %*
OM&A	**20**	**17**	*3*	*18 %*
Taxes, other than income taxes	**4**	**3**	*1*	*33 %*
Net other operating income	**(2)**	**(2)**	*—*	*— %*
Adjusted EBITDA[3]	**89**	**88**	*1*	*1 %*

(1) Gross installed capacity and availability for 2024 includes the 130 MW Garden Plain wind facility that achieved commercial operation in August 2023, the 48 MW Northern Goldfields solar facilities that achieved commercial operation in November 2023 and the 100 MW White Rock West wind facility that achieved commercial operation in January 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 months ended March 31, 2024, increased compared with the same period in 2023 primarily due to:

- Higher environmental attribute revenues;
- Higher production from the return to service of the Kent Hills wind facilities;
- Commercial operation of the Garden Plain and White Rock West wind facilities and the Northern Goldfields solar facilities; offset by
- Lower realized power prices in Alberta; and
- Weaker wind resource across the Alberta operating fleet.

Adjusted EBITDA for the three months ended March 31, 2024, increased compared with the same period 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 and White Rock West wind facilities and the Northern Goldfields solar facilities, salary escalations, higher insurance costs and long-term service agreement escalations.

Gas

3 months ended March 31	2024	2023	Change	
Gross installed capacity (MW)	3,087	3,084	3	— %
Availability (%)	94.6	96.4	(1.8)	(2)%
Production				
Contract sales volume (GWh)	1,504	1,003	501	50 %
Merchant sales volume (GWh)	2,045	2,249	(204)	(9)%
Purchased power (GWh)(1)	(21)	(80)	59	(74)%
Total production (GWh)	3,528	3,172	356	11 %
Revenues(2)	354	435	(81)	(19)%
Fuel and purchased power(2)	141	129	12	9 %
Carbon compliance	40	32	8	25 %
Gross margin(3)	173	274	(101)	(37)%
OM&A	46	41	5	12 %
Taxes, other than income taxes	3	4	(1)	(25)%
Net other operating income	(10)	(11)	1	(9)%
Adjusted EBITDA(3)	134	240	(106)	(44)%

(1) Power required to fulfill contractual obligations during planned and unplanned outages 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 months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower realized power and ancillary services prices from the Alberta merchant fleet driven by lower spot prices and the impact of lower-priced hedge contracts; and
- 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.

Adjusted EBITDA for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower revenues explained above;
- Higher fuel and purchased power from higher production;
- An increase in the carbon price from $65 per tonne to $80 per tonne, impacting gross margin from our Canadian gas assets; and
- Higher OM&A expenses mainly due to increased salary escalations; partially offset by
- Lower natural gas commodity costs at the Alberta gas assets.

Energy Transition

3 months ended March 31	2024	2023	Change	
Gross installed capacity (MW)	671	671	—	— %
Availability (%)	79.0	94.5	(15.5)	(16)%
Adjusted availability (%)[1]	79.0	94.5	(15.5)	(16)%
Production				
Contract sales volume (GWh)	830	820	10	1 %
Merchant sales volume (GWh)	933	1,343	(410)	(31)%
Purchased power (GWh)[2]	(962)	(866)	(96)	11 %
Total production (GWh)	801	1,297	(496)	(38)%
Revenues[3]	210	253	(43)	(17)%
Fuel and purchased power	166	181	(15)	(8)%
Gross margin[4]	44	72	(28)	(39)%
OM&A	18	17	1	6 %
Taxes, other than income taxes	—	1	(1)	(100)%
Adjusted EBITDA[4]	26	54	(28)	(52)%
Supplemental information:				
Highvale mine reclamation spend	3	2	1	50 %
Centralia mine reclamation spend	3	3	—	— %

(1) Adjusted for dispatch optimization.

(2) 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.

(3) 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.

(4) 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 months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower production due to higher unplanned outages at Centralia Unit 2; and
- Increased economic dispatch due to lower market prices.

Adjusted EBITDA for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower revenues as explained by the factors above; and
- Higher purchased power due to increased economic dispatch; partially offset by
- Lower fuel costs due to lower production volumes.

Mine reclamation spend for the three months ended March 31, 2024, was consistent compared with the same period in 2023.

Energy Marketing

3 months ended March 31	2024	2023	Change	
Revenues[1]	30	53	*(23)*	*(43)%*
OM&A	10	14	*(4)*	*(29)%*
Adjusted EBITDA[2]	20	39	*(19)*	*(49)%*

(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 months ended March 31, 2024, decreased compared with the same period in 2023. This was in line with management's expectations, but lower quarter over quarter, primarily due to:

- Lower realized settled trades in the first quarter of 2024 on market positions in comparison to the prior period; partially offset by
- Lower OM&A due to lower incentives.

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 March 31	2024	2023	Change	
OM&A	28	24	*4*	*17%*
Adjusted EBITDA[1]	(28)	(24)	*(4)*	*17%*

(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.

Adjusted EBITDA for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to increased spending 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 March 31, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	87	24	84	(3)	20	(28)	184
Canada, excluding Alberta	—	40	24	—	—	—	64
US	—	23	3	29	—	—	55
Australia	—	2	23	—	—	—	25
Adjusted EBITDA(1)	**87**	**89**	**134**	**26**	**20**	**(28)**	**328**
Earnings before income taxes							**267**

3 months ended March 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	106	31	178	(2)	39	(24)	328
Canada, excluding Alberta	—	30	25	—	—	—	55
US	—	27	2	56	—	—	85
Australia	—	—	35	—	—	—	35
Adjusted EBITDA(1)	106	88	240	54	39	(24)	503
Earnings before income taxes							383

(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 52 per cent of our capacity is located and 75 per cent of our Alberta assets are 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. Power is 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 ancillary services are dispatched into the energy market during times of supply tightness. 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 commercial and industrial customers and is supplemented with financial hedges.

In the three months ended March 31, 2024, 87 per cent of our energy production in Alberta was sold under long-term contracts or fixed-price hedges.

The Alberta hydro fleet provides ancillary services and grid reliability products such as Black Start service, 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 March 31	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	636	1,960	—	3,430
Total production (GWh)	313	494	2,366	—	3,173	283	502	2,369	—	3,154
Contract production (GWh)	—	239	608	—	847	—	176	150	—	326
Merchant production (GWh)	313	255	1,758	—	2,326	283	326	2,219	—	2,828
Hedged production (GWh)	84	36	1,788	—	1,908	165	—	1,880	—	2,046
Production contracted or hedged (%)	27%	56%	101%	—%	87%	—%	35%	86%	—%	70%
Revenues[(1)] ($)	103	38	244	1	386	121	44	325	2	492
Fuel and purchased power ($)	5	4	110	—	119	4	7	103	—	114
Carbon compliance ($)	—	—	36	—	36	—	—	29	—	29
Gross margin ($)	98	34	98	1	231	117	37	193	2	349

(1) 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.

Total production for the three months ended March 31, 2024, was 3,173 GWh compared to 3,154 GWh of electricity in the same period in 2023. The increase of 19 GWh, or 1 per cent, was primarily due to:

- Stronger production from the Alberta Hydro assets in response to high demand in periods of extreme cold conditions in the quarter; and
- The addition of the Garden Plain wind facility which was commissioned in August 2023; partially offset by
- Lower wind resource.

Hedged production volumes for the three months ended March 31, 2024 decreased compared to the same period in 2023, primarily from fewer strategic hedges executed for the first quarter of 2024.

Gross margin for the three months ended March 31, 2024, was $231 million compared to $349 million in the same period in 2023. The decrease of $118 million, or 34 per cent, was primarily due to:

- The impacts of lower Alberta realized spot prices and lower fixed-price hedges; partially offset by
- Higher environmental attribute revenues.

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

3 months ended March 31	2024	2023
Alberta Market		
Spot power price average per MWh	**99**	142
Natural gas price (AECO) per GJ	**1.94**	3.08
Carbon compliance price per tonne	**80**	65
Alberta Portfolio Results		
Realized merchant power price per MWh(1)	**119**	156
Hydro energy spot power price per MWh	**152**	168
Hydro ancillary spot price per MWh	**54**	60
Wind energy spot power price per MWh	**51**	89
Gas spot power price per MWh	**118**	156
Hedged power price average per MWh	**88**	136
Hedged volume (GWh)	**1,908**	2,046
Fuel and purchased power per MWh(2)	**50**	48
Carbon compliance cost per MWh(2)	**15**	12

(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 and purchased power per MWh and carbon compliance cost per MWh are calculated on production from carbon-emitting generation in the Gas and Energy Transition segments.

The average spot power price per MWh for the three months ended March 31, 2024 decreased from $142 per MWh in 2023 to $99 per MWh in 2024, primarily due to:

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

Realized merchant power price per MWh of production for the three months ended March 31, 2024, decreased by $37 per MWh, compared to the same period in 2023, primarily due to:

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

Fuel and purchased power cost per MWh for the three months ended March 31, 2024, increased by $2 per MWh, compared to the same period in 2023, primarily due to:

- Higher purchased power to fulfill contractual obligations; partially offset by
- Lower natural gas prices.

Carbon compliance cost per MWh of production for the three months ended March 31, 2024, increased by $3 per MWh, compared to the same period in 2023, primarily due to an increase in carbon pricing from $65 per tonne to $80 per tonne.

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. Typically, hydroelectric facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q2 2023	Q3 2023	Q4 2023	Q1 2024
Revenues	625	1,017	624	**947**
Earnings (loss) before income taxes	79	453	(35)	**267**
Net earnings (loss) attributable to common shareholders	62	372	(84)	**222**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.23	1.41	(0.27)	**0.72**
Cash flow from operating activities	11	681	310	**244**

	Q2 2022	Q3 2022	Q4 2022	Q1 2023
Revenues	458	929	854	1,089
Earnings (loss) before income taxes	(22)	126	7	383
Net earnings (loss) attributable to common shareholders	(80)	61	(163)	294
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.30)	0.23	(0.61)	1.10
Cash flow from (used in) operating activities(2)	(129)	204	351	462

(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.

(2) The cash flow used in operating activities for the second quarter of 2022 was negative due to unfavourable changes in working capital mainly due to movements in our collateral accounts related to higher commodity prices and volatility in the markets.

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 and the White Rock West wind facility in the first quarter of 2024; and
- The outage of the Kent Hills 1 and 2 wind facilities from the first quarter of 2022 through to the fourth quarter of 2023. The remediation project was completed in the first quarter of 2024.

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

- Higher production in the first, second, and third quarters of 2023 and in the first quarter of 2024; and
- Lower realized pricing in the third and fourth quarters of 2023 and the first quarter 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.

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

- The items described above;
- Lower natural gas commodity pricing in the last four quarters compared to the same periods in the prior year;
- Higher costs of carbon per tonne. In 2022, 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 2022, lower carbon costs as the Company utilized emission credits to settle a portion of our greenhouse gas ("GHG") obligation;
- OM&A costs in the second quarter of 2023 and the first quarter of 2024 were higher than the same periods in the prior years due to higher spending on strategic and growth initiatives;
- Depreciation in the last three 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;
- The effect of changes in decommissioning provisions for retired assets from an increase in discount rates in the second and third quarters of 2022;
- The effects of changes in decommissioning provisions for retired assets due to changes in estimated cash flows and changes in useful lives, recognized in the third quarter of 2022 and 2023;
- Insurance proceeds for the single tower failure at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility recorded in all quarters, with higher amounts recognized in the second quarter of 2022 and 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 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 to our shareholders. To support this strategy, we maintain a growing pipeline 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.

Impact of Alberta Government Electricity Announcements on Renewable Projects

On Feb. 28, 2024, the Government of Alberta ("GoA") announced new restrictions and requirements that it will impose on new renewable projects and power plant regulatory approval processes. This includes prohibiting wind generation development within 35 kilometres of a protected area or other areas designated as a "pristine viewscape" by the GoA, restricting renewable development on class 1 and 2 agricultural lands, imposing new mandatory requirements to post bonds and/or provide financial security to meet reclamation obligations, and granting municipalities standing in Alberta Utilities Commission ("AUC") power plant regulatory proceedings.

The Riplinger wind project was impacted by the new restriction, specifically the restrictions on development near protected areas and pristine viewscapes, and will not be advanced. The project has been removed from our early-stage development projects.

On March 11, 2024, the GoA announced a wholesale electricity market redesign and associated interim regulations. This announcement followed a review process that kicked off in mid-2023 and was based on the GoA's acceptance of recommendations made to the Minister of Affordability and Utilities by the AESO and the Market Surveillance Administrator to pursue detailed design work on a "Restructured Energy Market". While these changes have had an immediate impact on market stability, TransAlta believes the near-term impacts on the Company's existing assets will be muted given current market conditions, while new growth projects will be paused until the new market structure is defined. The Company will remain actively involved in the design process through consultation efforts with the GoA and associated agencies.

The interim regulations filed by the GoA prescribe specific changes that the AESO and AUC must implement by July 1, 2024:

- The Market Power Mitigation Regulation imposes an offer cap on the gas-fired generating units controlled by a market participant who has offer control of at least 5 per cent of total installed capacity. The offer cap would only restrict our offering price, not our settlement price, and would be based on the greater of $125 per MWh or 25 times the day-ahead natural gas price and is triggered when a hypothetical high efficiency natural gas fired combined cycle generator has earned 2-months' worth of net revenues. This calculation is based upon a monthly cumulative settlement calculation that is set out in the regulation and is applied for the remainder of the calendar month in which the offer cap is triggered.
- The Supply Cushion Regulation requires the AESO to forecast and direct generation, that takes one hour or more to synchronize to the grid, into service 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 covers incremental start-up and variable costs if the pool price revenues are not sufficient to compensate.

The AESO currently projects that the Restructured Energy Market design will be finalized by the end of 2025 with implementation in 2026. The proposed changes include, but are not limited to: (i) the introduction of a day-ahead market and administrative scarcity pricing mechanism (to replace economic withholding; (ii) the allowance of negative pricing alongside a higher price cap; and (iii) the reduction of settlement windows (from one hour to fifteen or five minutes). The proposal also intends to implement additional market power mitigation, centralize dispatch and incentivize new generation to locate near existing infrastructure with sufficient capacity.

As a result of these announcements and surrounding uncertainty, the Company has paused the development of three advanced-stage greenfield projects in Alberta – WaterCharger, Tempest and Pinnacle. These projects will be reconsidered once the GoA provides sufficient clarity regarding future market structure, due to the market exposure of each project.

The Company has a robust pipeline of approximately 5 GW distributed among Canada, the United States and Australia, and will continue to allocate development capital to markets which bring geographic diversity, stability and strong returns.

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.

During the three months ended March 31, 2024, the Company purchased and cancelled a total of 3,460,300 common shares, at an average price of $9.36 per common share, for a total cost of $32 million.

Advanced-Stage Development

These projects have detailed engineering, advanced positions in the interconnection queue and/or are progressing offtake opportunities. Projects in advanced-stage development 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	Estimated spend	Average annual EBITDA(1)
Tempest	Wind	Alberta	On hold	100	On hold	On hold
SCE Capacity Expansion	Gas	Western Australia	2024	94	AU$210-AU$230	AU$28-AU$32
WaterCharger	Battery Storage	Alberta	On hold	180	On hold	On hold
Pinnacle 1 & 2	Gas	Alberta	On hold	44	On hold	On hold
Total(2)				**418**	**$191 - $209**	**$25 - $29**

(1) This item is not defined, 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 was converted using a Canadian dollar forward exchange rate for 2024.

Early-Stage Development

These projects are in the early stages and may or may not move ahead. Generally, these projects will have:

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

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

Project	Type	Region	Potential investment date[1]	MW
Canada				
New Brunswick Battery	Battery	New Brunswick	2025	10
Sunhills Solar	Solar	Alberta	2026	170
McNeil Solar	Solar	Alberta	2026	57
Tent Mountain Pumped Storage[2]	Hydro	Alberta	2026	160
Provost	Wind	Alberta	2026	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	250-500
		Total		**1,747 - 2,597**
United States				
Monument Road	Wind	Nebraska	2025	152
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
Prairie Violet	Wind	Illinois	2026	130
Quick Draw	Wind	Texas	2026	174
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	250-500
		Total		**2,348 - 2,598**
Australia				
Boodarie Solar	Solar	Western Australia	2024	50
Southern Cross Energy	Wind and Solar	Western Australia	TBD	120
Other Australian Opportunities	Gas, Solar, Transmission	Western Australia	2024+	230
		Total		**400**
Canada, United States and Australia		**Total**		**4,495 - 5,595**

(1) Potential investment 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 projects have been approved by the Board of Directors, have executed power purchase agreements ("PPAs") and are currently under construction or in the process of being commissioned. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore permanent financing solutions on an asset-by-asset basis.

We are continually monitoring the timing and costs on our projects under construction. Our US projects have experienced schedule delays and increased costs attributable to complexities relating to transmission interconnections and wind turbine erection. The White Rock East wind facility achieved commercial operation on April 22, 2024, and has therefore been removed from the table below. The 200 MW Horizon Hill wind project transmission lines are fully energized and is expected to achieve commercial operation in the second quarter of 2024.

				Total project (millions)					
Project	**Type**	**Region**	**MW**	**Estimated spend**	**Spent to date**	**Target completion date**	**PPA Term[(1)]**	**Average annual EBITDA[(2)]**	**Status**
United States									
Horizon Hill	**Wind**	OK	200	US$330 — US$340	US$307	Q2 2024	—	US$31-US$33	• Long-term PPA executed • Installation/assembly complete • Final stages of commissioning underway
Australia									
Mount Keith West Network Upgrade	**Transmission**	WA	n/a	AU$37 — AU$40	AU$13	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[(3)]			**200**	**$502 — $519**	**$423**			**$47 - $50**	

(1) The PPA term is confidential for the Horizon Hill wind project.

(2) 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.

(3) 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 March 31, 2024:

	March 31, 2024	Dec. 31, 2023	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**419**	348	71
Trade and other receivables	**690**	807	(117)
Risk management assets	**240**	151	89
Other current assets[1]	**260**	274	(14)
Total current assets	**1,609**	1,580	29
Non-current assets			
Risk management assets	**135**	52	83
Property, plant and equipment, net	**5,659**	5,714	(55)
Long-term portion of finance lease receivable	**211**	171	40
Other non-current assets[2]	**1,138**	1,142	(4)
Total non-current assets	**7,143**	7,079	64
Total assets	**8,752**	8,659	93
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**674**	797	(123)
Exchangeable securities	**745**	—	745
Other current liabilities[3]	**914**	945	(31)
Total current liabilities	**2,333**	1,742	591
Non-current liabilities			
Exchangeable securities	**—**	744	(744)
Other non-current liabilities[4]	**4,487**	4,509	(22)
Total non-current liabilities	**4,487**	5,253	(766)
Total liabilities	**6,820**	6,995	(175)
Equity			
Equity attributable to shareholders	**1,808**	1,537	271
Non-controlling interests	**124**	127	(3)
Total equity	**1,932**	1,664	268
Total liabilities and equity	**8,752**	8,659	93

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

(2) Includes investments, right-of-use assets, intangible assets, goodwill, deferred income tax assets and other assets.

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

(4) Includes credit facilities, long-term debt and lease liabilities, long-term decommissioning and other provisions, deferred income tax liabilities, long-term portion of risk management liabilities, contract liabilities and defined benefit obligation and other long-term 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 $724 million as at March 31, 2024 (Dec. 31, 2023 – excess of current assets over current liabilities of $162 million), primarily as a result of the exchangeable securities being reclassified from long-term to current liabilities in the period as the 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.

Current assets increased by $29 million to $1,609 million as at March 31, 2024, from $1,580 million as at Dec. 31, 2023, primarily due to:

- Higher risk management assets mainly due to volatility in market prices;
- Higher collateral provided by the Energy Marketing segment due to trading activity and volatility in market prices;
- Higher cash and cash equivalents; partially offset by
- Lower trade receivables from lower revenues recognized in the first quarter of 2024.

Current liabilities increased by $591 million from $1,742 million as at Dec. 31, 2023, to $2,333 million as at March 31, 2024, mainly due to:

- The exchangeable securities classified as current as the 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; and
- Higher collateral received by the Energy Marketing segment due to trading activity and volatility in market prices; partially offset by
- Lower accounts payable and accrued liabilities.

Non-Current Assets

Non-current assets as at March 31, 2024, were $7,143 million, an increase of $64 million from $7,079 million as at Dec. 31, 2023, primarily due to:

- Higher risk management assets due to volatility in market pricing across multiple markets; and
- Higher net investment in finance leases related to the Northern Goldfields solar facilities; partially offset by
- Lower property, plant and equipment ("PP&E") resulting from depreciation of $124 million and lower capital additions of $216 million.

Non-Current Liabilities

Non-current liabilities as at March 31, 2024, were $4,487 million, a decrease of $766 million from $5,253 million as at Dec. 31, 2023, mainly due to the exchangeable securities being classified to current liabilities.

Total Equity

As at March 31, 2024, the increase in total equity of $268 million was due to:

- Net earnings of $238 million; and
- Net gains on derivatives from cash flow hedges of $84 million; partially offset by
- Share repurchases under the NCIB of $32 million; and
- Distributions to non-controlling interests of $19 million.

Financial Capital

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

Capital Structure

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

	March 31, 2024		Dec. 31, 2023	
	$	%	$	%
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**4**	251	5
Recourse debt - US senior notes	**938**	**16**	911	17
Credit facilities	**397**	**7**	397	7
Less: cash and cash equivalents[(1)]	**(417)**	**(7)**	(345)	(6)
Less: other cash and liquid assets[(2)]	**—**	**—**	(12)	—
Net senior unsecured debt	**1,169**	**20**	1,202	23
Other debt liabilities				
Exchangeable debentures	**345**	**6**	344	6
Non-recourse debt				
TAPC Holdings LP bond	**83**	**1**	85	1
Pingston bond	**39**	**1**	39	1
Melancthon Wolfe Wind bond	**168**	**3**	168	3
New Richmond Wind bond	**103**	**2**	103	2
Kent Hills Wind bond	**190**	**3**	193	3
Windrise Wind bond	**161**	**3**	164	3
South Hedland non-recourse debt	**673**	**12**	691	13
OCP Bond	**205**	**4**	217	4
US tax equity financing	**103**	**2**	104	1
Lease liabilities	**145**	**3**	143	3
Total consolidated net debt[(3)(4)(5)]	**3,384**	**60**	3,453	63
Exchangeable preferred securities[(5)]	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**3,258**	**57**	3,285	60
Preferred shares	**942**	**16**	942	17
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,392)**	**(42)**	(2,690)	(49)
Non-controlling interests	**124**	**2**	127	2
Total capital	**5,716**	**100**	5,517	100

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

(2) Includes 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 and also 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) 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.

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

(5) 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 $779 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 March 31, 2024		Utilized			
Credit facilities	Facility size	Outstanding letters of credit[1]	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta syndicated credit facility	1,950	492	—	1,458	Q2 2027
TransAlta bilateral credit facilities	240	181	—	59	Q2 2025
TransAlta Term Facility	400	—	400	—	Q3 2024
Total committed	**2,590**	**673**	**400**	**1,517**	
Non-committed					
TransAlta demand facilities	400	201	—	199	N/A
Total non-committed	**400**	**201**	**—**	**199**	

(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.

Non-Recourse Debt and Other

The Melancthon Wolfe Wind LP, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd. and Windrise Wind LP 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 first quarter of 2024, with the exception of Kent Hills Wind LP. Kent Hills Wind LP cannot make any distributions to its partners until the independent engineer's report has been finalized and the the debt service coverage ratio is met. The funds in the entities that have accumulated since the first quarter test will remain there until the next debt service coverage test can be performed in the second quarter of 2024. At March 31, 2024, $88 million (Dec. 31, 2023 – $79 million) of cash was subject to these financial restrictions.

At March 31, 2024, $4 million (AU$4 million) of funds held by TEC Hedland Pty Ltd are not able to be accessed by other corporate entities as the funds must be solely used by the project entities for the purpose of paying major maintenance costs.

Additionally, certain non-recourse bonds require that reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

Returns to Providers of Capital

Interest Income and Interest Expense

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

3 months ended March 31	2024	2023
Interest income	**7**	15
Interest on debt	**49**	50
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares	**7**	7
Capitalized interest	**(14)**	(13)
Interest on lease liabilities	**2**	2
Credit facility fees, bank charges and other interest	**6**	8
Tax shield on tax equity financing	**—**	(1)
Accretion of provisions	**12**	14
Interest expense	**69**	74

Interest income was lower due to lower cash balances. Interest expense was lower when compared to the same period in 2023, primarily due to lower outstanding letters of credit resulting in lower fees, and lower accretion of provisions.

Share Capital

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

	Number of shares (millions)		
As at	**May 2, 2024**	**March 31, 2024**	**Dec. 31, 2023[1]**
Common shares issued and outstanding, end of period	**304.1**	**306.5**	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 invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the 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 March 31, 2024, TransAlta Renewables is a wholly-owned subsidiary and has no remaining non-controlling interest.

As at March 31, 2024, the Company owned 50.01 per cent of TA Cogen (March 31, 2023 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness). As at March 31, 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 attributable to non-controlling interests for the three months ended March 31, 2024, decreased by $24 million, compared to 2023, primarily as a result of lower TA Cogen net earnings attributable to non-controlling interests resulting from lower production and lower merchant pricing in the Alberta market and no net earnings attributable to non-controlling interests in TransAlta Renewables in 2024.

Cash Flows

Cash and cash equivalents for the three months ended March 31, 2024, has decreased by $828 million, 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 three months ended March 31, 2024 and March 31, 2023:

3 months ended March 31	2024	2023	Increase/ (decrease)
Cash and cash equivalents, beginning of period	**348**	1,134	(786)
Provided by (used in):			
Operating activities	**244**	462	(218)
Investing activities	**(58)**	(182)	124
Financing activities	**(114)**	(165)	51
Translation of foreign currency cash	**(1)**	(2)	1
Cash and cash equivalents, end of period	**419**	1,247	(828)

Cash Flow from Operating Activities

Cash from operating activities for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	3 months ended March 31
Cash flow from operating activities for the three months ended March 31, 2023	462
Lower gross margin: Lower revenues net of unrealized gains from risk management activities and higher carbon compliance costs.	(209)
Lower current income tax expense due to decrease in earnings before tax.	33
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, partially offset by lower accounts receivable from lower revenues and higher collateral received related to derivative instruments.	(35)
Other	(7)
Cash flow from operating activities for the three months ended March 31, 2024	**244**

Cash Flow used in Investing Activities

Cash used in investing activities for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	3 months ended March 31
Cash flow used in investing activities for the three months ended March 31, 2023	(182)
Lower additions to PP&E: Additions in 2023 were mainly for the construction of the Garden Plain wind facility which achieved commercial operation in August 2023, the Northern Goldfields solar facilities which achieved commercial operation in November 2023, and the construction of the White Rock and Horizon Hill wind projects. In 2024, the White Rock and Horizon Hill wind projects were nearing completion resulting in lower additions.	216
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.	(22)
Unfavourable change in non-cash investing working capital balances: Lower capital accruals.	(70)
Cash flow used in investing activities for the three months ended March 31, 2024	**(58)**

Cash Flow used in Financing Activities

Cash used in financing activities for the three months ended March 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	3 months ended March 31
Cash flow used in financing activities for the three months ended March 31, 2023	(165)
Lower distributions paid to non-controlling interests: Timing of distributions by TA Cogen and no distributions to non-controlling interests by TransAlta Renewables Inc. in 2024.	57
Other	(6)
Cash flow used in financing activities for the three months ended March 31, 2024	**(114)**

Other Consolidated Analysis

Commitments

The Company has not incurred any additional contractual commitments in the three months ended March 31, 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 three months ended March 31, 2024.

Financial Instruments

Refer to Note 14 of the notes to the audited annual 2023 consolidated financial statements and Note 9 and 10 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 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 March 31, 2024, Level III instruments had a net liability carrying value of $80 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 months ended March 31, 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. 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 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.
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- 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

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 March 31, 2024:

	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	112	139	433	217	52	—	953	(6)	—	947
Reclassifications and adjustments:										
Unrealized mark-to-market gain	(5)	(21)	(91)	(6)	(3)	—	(126)	—	126	—
Realized gain (loss) on closed exchange positions	—	—	8	(1)	(19)	—	(12)	—	12	—
Decrease in finance lease receivable	—	1	4	—	—	—	5	—	(5)	—
Finance lease income	—	1	1	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	107	120	354	210	30	—	821	(6)	132	947
Fuel and purchased power	6	9	142	166	—	—	323	—	—	323
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	6	9	141	166	—	—	322	—	1	323
Carbon compliance	—	—	40	—	—	—	40	—	—	40
Gross margin	101	111	173	44	30	—	459	(6)	131	584
OM&A	13	20	46	18	10	28	135	(1)	—	134
Taxes, other than income taxes	1	4	3	—	—	—	8	—	—	8
Net other operating income	—	(2)	(10)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA(2)	87	89	134	26	20	(28)	328			
Equity income										1
Finance lease income										2
Depreciation and amortization										(124)
Asset impairment charges										(1)
Interest income										7
Interest expense										(69)
Foreign exchange loss and other										(3)
Earnings before income taxes										267

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is 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 March 31, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	125	115	495	267	92	—	1,094	(5)	—	1,089
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(1)	—	(64)	(14)	16	—	(63)	—	63	—
Realized gain (loss) on closed exchange positions	—	—	(13)	—	(55)	—	(68)	—	68	—
Decrease in finance lease receivable	—	—	13	—	—	—	13	—	(13)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	124	115	435	253	53	—	980	(5)	114	1,089
Fuel and purchased power	5	9	130	181	—	—	325	—	—	325
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	9	129	181	—	—	324	—	1	325
Carbon compliance	—	—	32	—	—	—	32	—	—	32
Gross margin	119	106	274	72	53	—	624	(5)	113	732
OM&A	12	17	41	17	14	24	125	(1)	—	124
Taxes, other than income taxes	1	3	4	1	—	—	9	—	—	9
Net other operating income	—	(2)	(11)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA[2]	106	88	240	54	39	(24)	503			
Equity income										2
Finance lease income										4
Depreciation and amortization										(176)
Asset impairment reversals										3
Interest income										15
Interest expense										(74)
Foreign exchange loss										(3)
Earnings before income taxes										383

(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 March 31	2024	2023
Cash flow from operating activities[1]	**244**	462
Change in non-cash operating working capital balances	**(7)**	(42)
Cash flow from operations before changes in working capital	**237**	420
Adjustments		
Share of adjusted FFO from joint venture[1]	**2**	3
Decrease in finance lease receivable	**5**	13
Realized loss on closed exchanged positions	**(12)**	(68)
Other[2]	**7**	6
FFO[3]	**239**	374
Deduct:		
Sustaining capital[1]	**1**	(20)
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(76)
Principal payments on lease liabilities	**(1)**	(2)
Other	**(1)**	—
FCF[3]	**206**	263
Weighted average number of common shares outstanding in the period	**308**	268
FFO per share[3]	**0.78**	1.40
FCF per share[3]	**0.67**	0.98

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

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

(3) 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 March 31	2024	2023
Adjusted EBITDA(1)(4)	**328**	503
Provisions	**—**	3
Net interest expense(2)	**(48)**	(45)
Current income tax expense	**(27)**	(60)
Realized foreign exchange loss	**(8)**	(7)
Decommissioning and restoration costs settled	**(7)**	(7)
Other non-cash items	**1**	(13)
FFO(3)(4)	**239**	374
Deduct:		
Sustaining capital(4)	**1**	(20)
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(76)
Principal payments on lease liabilities	**(1)**	(2)
Other	**(1)**	—
FCF(3)(4)	**206**	263

(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	March 31, 2024	Dec. 31, 2023
Period-end long-term debt(1)	**3,457**	3,466
Exchangeable debentures	**345**	344
Less: Cash and cash equivalents(2)	**(417)**	(345)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(3)	**671**	671
Other(4)	**—**	(12)
Adjusted net debt(5)	**4,056**	4,124
Adjusted EBITDA(6)	**1,457**	1,632
Adjusted net debt to adjusted EBITDA (times)	**2.8**	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 (nil for the period ended March 31, 2024 and $17 million 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 March 31, 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:

	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	$0.24 per share annualized	$0.22 per share annualized

(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	2024 Assumptions
Alberta spot ($/MWh)	$75 to $95
Mid-C spot (US$/MWh)	US$75 to US$85
AECO gas price ($/GJ)	$1.75 to $2.25

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/-$3 million impact on adjusted EBITDA for balance of year 2024.

Other assumptions relevant to the 2024 outlook

	2024 Expectations
Energy Marketing gross margin	$110 million to $130 million
Sustaining capital	$130 million to $150 million
Corporate cash taxes	$95 million to $130 million
Cash interest	$240 million to $260 million

Alberta Hedging

Range of hedging assumptions	Q2 2024	Q3 2024	Q4 2024	Full year 2025	Full year 2026
Hedged production (GWh)	1,983	2,249	2,153	4,614	3,215
Hedge price ($/MWh)	$85	$85	$85	$79	$80
Hedged gas volumes (GJ)	14 million	14 million	15 million	28 million	18 million
Hedge gas prices ($/GJ)	$2.80	$2.84	$2.80	$3.52	$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 March 31, 2024, we had access to $1.7 billion in liquidity, including $417 million in cash, net of bank overdraft.

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.

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 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 10 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 Climate Plan

In April 2021, the Government of Canada announced a revised national GHG emissions reductions target of 40 per cent to 45 per cent below 2005 levels by 2030. In 2022, the Government of Canada's Department of 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 on Aug. 19, 2023. A seventy five-day formal comment period closed on Nov. 2, 2023. The Government of Canada released a public update report on Feb. 15, 2024 with a 30-day comment period for feedback. The CER is expected to be finalized in 2024.

In the 2023 federal budget, the government announced additional investment tax credit ("ITC") categories and details aimed at supporting the net zero transition. The ITCs are expected to support investments in net zero technologies in the electricity sector. On June 6, 2023 the Department of Finance launched consultations seeking feedback on design details regarding the ITC components included in Budget 2023. The Government of Canada subsequently released draft legislation on Aug. 4, 2023, for consultation to advance key budget priorities, including the Clean Technology ITC, Clean Technology Manufacturing ITC and ITC for Carbon Capture Utilization and Storage. Legislation is expected to be finalized in 2024. A draft legislative proposal for the Hydrogen and Clean Technology Manufacturing ITC was also released by the Government of Canada on Dec. 20, 2023 for consultation.

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 Feb. 28, 2024, the Government of Alberta announced new restrictions and requirements that it will impose on new renewable projects and power plant regulatory approval processes. This 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, and granting municipalities standing in AUC power plant regulatory proceedings. The Government and regulatory agencies are expected to plan future engagements to consult on and implement these new requirements. The Riplinger wind project was impacted by the new restriction, specifically the restrictions on development near protected areas and pristine viewscapes, and will not be advanced. The project has been removed from our early development projects.

The Government also lifted its renewables approvals pause, which was in place from Aug. 3, 2023 to Feb. 29, 2024.

The Government also stated that it would bring forth changes to the Transmission Regulation by July 2024. The Government conducted two consultations in the previous three years that considered potential changes to transmission policy and the regulation. The Government alluded to changes that it seeks to make to allocate transmission costs to renewable projects.

The AUC provided a report to the Minister of Affordability and Utilities on the impacts of renewable growth on the generation supply mix and system reliability in Alberta. The AUC's report is based on a modeling study that concludes that additional renewable growth will reduce energy prices but also squeeze out thermal dispatchable resources and result in deteriorating system reliability that breaches Alberta's long term adequacy thresholds.

On March 11, 2024, the Government announced its decision to accept the AESO recommendation to pursue detailed design work on a "Restructured Energy Market". Concurrently, the Government publicly released the Market Surveillance Administrator's Dec. 21, 2023 report and AESO's Jan. 31, 2024 report to the Minister; both reports proposed incremental changes to the existing energy market that were largely consistent with and complementary to each other.

The AESO plans to develop the detailed design using an industry working group that will commence regular meetings in mid-April and will work towards a first or second quarter of 2025 target date for a full Restructured Energy Market detailed design proposal. TransAlta will be an active participant in the AESO's working group process. The new market rules that will implement the detailed design will be filed with the AUC in the first or second quarter of 2025 and are planned to be approved by the fourth quarter of 2025 or the first quarter of 2026.

The Government also filed two new interim regulations under Ministerial Order on March 11, 2024. The new regulations prescribe specific changes that the AESO and AUC must implement through new and amended Independent System Operator rules by July 1, 2024. Both regulations expire on Nov. 30, 2027, when the new Restructured Energy Market is expected to be implemented.

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 gas-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 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. The impacts of this regulation are still unclear given that lack of any details about the proposed mechanism - notably, the AESO has existing authority to make these decisions and provide compensation for costs but has never issued a directive to a long-lead time unit.

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. The Canadian Securities Administrators anticipates seeking comment on a revised rule for climate-related disclosures after considering the SEC's final rules and the Canadian Sustainability Standards Board's climate-related disclosures standard to be released in 2024.

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.

Prime Minister Anthony Albanese has worked quickly to implement one of his government's key energy policies, the Powering Australia Plan, which includes: the Rewiring the Nation initiative that will provide AU$20 billion to support the Australian Energy Market Operator's ("AEMO") integrated system plan to modernize the transmission system and enable additional renewable penetration; Powering the Regions Fund (AU$1.9 billion) supporting industry to decarbonize, developing new clean energy industries and supporting workforce development; and a AU$15 billion National Reconstruction Fund to diversify and transform Australia's economy and industry, including investments in green metals, clean energy component manufacturing and deployment of low-emissions technologies. Decarbonization efforts have been centered on funding for clean technologies, upgrading electricity grid to support more renewables, regulating and reporting of GHGs, and incentivizing zero-emission vehicles adoption.

TransAlta continues to monitor the development of climate-related financial disclosure legislation by the Australian Government, which is anticipated to be in effect in 2024.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the three months ended March 31, 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 March 31, 2024, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings

(in millions of Canadian dollars except where noted)

	3 months ended March 31	
Unaudited	**2024**	**2023**
Revenues (Note 3)	**947**	1,089
Fuel and purchased power (Note 4)	**323**	325
Carbon compliance (Note 4)	**40**	32
Gross margin	**584**	732
Operations, maintenance and administration (Note 4)	**134**	124
Depreciation and amortization	**124**	176
Asset impairment charges (reversals)	**1**	(3)
Taxes, other than income taxes	**8**	9
Net other operating income	**(12)**	(13)
Operating income	**329**	439
Equity income	**1**	2
Finance lease income	**2**	4
Interest income	**7**	15
Interest expense (Note 5)	**(69)**	(74)
Foreign exchange loss and other	**(3)**	(3)
Earnings before income taxes	**267**	383
Income tax expense (Note 6)	**29**	49
Net earnings	**238**	334
Net earnings attributable to:		
TransAlta shareholders	**222**	294
Non-controlling interests (Note 7)	**16**	40
	238	334
Weighted average number of common shares outstanding in the period (*millions*)	**308**	268
Net earnings per share attributable to common shareholders, basic and diluted (Note 14)	**0.72**	1.10

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2024**	**2023**
Net earnings	**238**	334
Other comprehensive income		
Net actuarial gains on defined benefit plans, net of tax[1]	**7**	—
Total items that will not be reclassified subsequently to net earnings	**7**	—
Gains on translating net assets of foreign operations	**6**	—
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**(10)**	1
Gains on derivatives designated as cash flow hedges, net of tax[3]	**46**	29
Reclassification of losses on derivatives designated as cash flow hedges to net earnings, net of tax[4]	**38**	40
Total items that will be reclassified subsequently to net earnings	**80**	70
Other comprehensive income	**87**	70
Total comprehensive income	**325**	404
Total comprehensive income attributable to:		
TransAlta shareholders	**309**	360
Non-controlling interests (Note 7)	**16**	44
	325	404

(1) Net of income tax expense of $2 million for the three months ended March 31, 2024 (March 31, 2023 – nil).

(2) Net of income tax recovery of $1 million for the three months ended March 31, 2024 (March 31, 2023 – nil).

(3) Net of income tax expense of $12 million for the three months ended March 31, 2024 (March 31, 2023 – $8 million expense).

(4) Net of reclassification of income tax expense of $10 million for the three months ended March 31, 2024 (March 31, 2023 – $11 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	March 31, 2024	Dec. 31, 2023
Current assets		
Cash and cash equivalents	**419**	348
Restricted cash (Note 13)	**46**	69
Trade and other receivables (Note 8)	**690**	807
Prepaid expenses and other	**63**	48
Risk management assets (Note 9 and 10)	**240**	151
Inventory	**151**	157
	1,609	1,580
Non-current assets		
Investments	**144**	138
Long-term portion of finance lease receivables (Note 11)	**211**	171
Risk management assets (Note 9 and 10)	**135**	52
Property, plant and equipment (Note 12)	**5,659**	5,714
Right-of-use assets	**118**	117
Intangible assets	**217**	223
Goodwill	**464**	464
Deferred income tax assets	**17**	21
Other assets	**178**	179
Total assets	**8,752**	8,659
Current liabilities		
Bank overdraft	**2**	3
Accounts payable and accrued liabilities (Note 8)	**674**	797
Current portion of decommissioning and other provisions	**70**	35
Risk management liabilities (Note 9 and 10)	**277**	314
Current portion of contract liabilities	**2**	3
Income taxes payable	**12**	9
Dividends payable (Note 14 and 15)	**18**	49
Exchangeable securities (Note 2)	**745**	—
Current portion of long-term debt and lease liabilities (Note 13)	**533**	532
	2,333	1,742
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 13)	**2,924**	2,934
Exchangeable securities (Note 2)	**—**	744
Decommissioning and other provisions	**633**	654
Deferred income tax liabilities	**406**	386
Risk management liabilities (Note 9 and 10)	**280**	274
Contract liabilities	**16**	10
Defined benefit obligation and other long-term liabilities	**228**	251
Equity		
Common shares (Note 14)	**3,258**	3,285
Preferred shares (Note 15)	**942**	942
Contributed surplus	**25**	41
Deficit	**(2,340)**	(2,567)
Accumulated other comprehensive loss	**(77)**	(164)
Equity attributable to shareholders	**1,808**	1,537
Non-controlling interests (Note 7)	**124**	127
Total equity	**1,932**	1,664
Total liabilities and equity	**8,752**	8,659

Commitments and contingencies (Note 16)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

3 months ended March 31, 2024	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	—	—	—	**222**	—	**222**	**16**	**238**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	**(4)**	**(4)**	—	**(4)**
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	**84**	**84**	—	**84**
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	**7**	**7**	—	**7**
Total comprehensive income	—	—	—	**222**	**87**	**309**	**16**	**325**
Shares purchased under normal course issuer bid ("NCIB") (Note 14)	**(37)**	—	—	**5**	—	**(32)**	—	**(32)**
Provision for repurchase of shares under the automatic share purchase plan ("ASPP") (Note 14)	**(3)**	—	—	—	—	**(3)**	—	**(3)**
Share-based payment plans and stock options exercised	**13**	—	**(16)**	—	—	**(3)**	—	**(3)**
Distributions declared to non-controlling interests (Note 7)	—	—	—	—	—	—	**(19)**	**(19)**
Balance, March 31, 2024	**3,258**	**942**	**25**	**(2,340)**	**(77)**	**1,808**	**124**	**1,932**

3 months ended March 31, 2023	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2022	2,863	942	41	(2,514)	(222)	1,110	879	1,989
Net earnings	—	—	—	294	—	294	40	334
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	1	1	—	1
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	69	69	—	69
Intercompany and third-party FVTOCI investments	—	—	—	—	(4)	(4)	4	—
Total comprehensive income	—	—	—	294	66	360	44	404
Shares purchased under NCIB (Note 14)	(34)	—	—	(2)	—	(36)	—	(36)
Provision for repurchase of shares under the ASPP (Note 14)	(37)	—	—	—	—	(37)	—	(37)
Effect of share-based payment plans	7	—	(18)	—	—	(11)	—	(11)
Distributions paid and payable, to non-controlling interests (Note 7)	—	—	—	—	—	—	(76)	(76)
Balance, March 31, 2023	2,799	942	23	(2,222)	(156)	1,386	847	2,233

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2024**	**2023**
Operating activities		
Net earnings	**238**	334
Depreciation and amortization	**124**	176
Accretion of provisions (Note 5)	**12**	14
Decommissioning and restoration costs settled	**(7)**	(7)
Deferred income tax expense (recovery) (Note 6)	**2**	(11)
Unrealized gain from risk management activities	**(125)**	(64)
Unrealized foreign exchange (gain) loss	**(4)**	2
Asset impairment charges (reversals)	**1**	(3)
Equity loss (income), net of distributions from investments	**1**	(1)
Other non-cash items	**(5)**	(20)
Cash flow from operations before changes in working capital	**237**	420
Change in non-cash operating working capital balances	**7**	42
Cash flow from operating activities	**244**	462
Investing activities		
Additions to property, plant and equipment (Note 12)	**(68)**	(284)
Additions to intangible assets	**(1)**	(3)
Restricted cash (Note 13)	**22**	23
Repayment from loan receivable	**—**	4
Proceeds on sale of property, plant and equipment	**1**	23
Realized gain on financial instruments	**—**	6
Decrease in finance lease receivable	**5**	13
Other	**12**	(5)
Change in non-cash investing working capital balances	**(29)**	41
Cash flow used in investing activities	**(58)**	(182)
Financing activities		
Repayment of long-term debt (Note 13)	**(29)**	(29)
Dividends paid on common shares (Note 14)	**(17)**	(15)
Dividends paid on preferred shares (Note 15)	**(13)**	(13)
Repurchase of common shares under NCIB (Note 14)	**(32)**	(34)
Proceeds on issuance of common shares	**3**	2
Distributions paid to subsidiaries' non-controlling interests (Note 7)	**(19)**	(76)
Decrease in lease liabilities	**(1)**	(2)
Financing fees and other	**—**	2
Change in non-cash financing working capital balances	**(6)**	—
Cash flow used in financing activities	**(114)**	(165)
Cash flow from operating, investing and financing activities	**72**	115
Effect of translation on foreign currency cash	**(1)**	(2)
Increase in cash and cash equivalents	**71**	113
Cash and cash equivalents, beginning of period	**348**	1,134
Cash and cash equivalents, end of period	**419**	1,247
Cash taxes paid	**12**	37
Cash interest paid	**58**	62
Cash interest received	**6**	14

See accompanying notes.

Notes to the Condensed Consolidated Financial Statements

(Unaudited)

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Company") was incorporated under the Canada Business Corporations Act in March 1985. The Company became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

B. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in compliance with International Accounting Standard ("IAS") 34 Interim Financial Reporting using the same accounting policies as those used in the Company's most recent audited annual consolidated financial statements, except as outlined in Note 2. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Company's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Company's most recent audited annual consolidated financial statements which are available on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.

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

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

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

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of TransAlta's Board of Directors (the "Board") on May 2, 2024.

C. Significant Accounting Judgements and Key Sources of Estimation Uncertainty

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

During 2023, nickel prices weakened due to increased supply and lower demand. The uncertainty related to nickel prices have been considered in our estimates and our contracts with customers and there have been no significant changes in our estimates.

During the three months ended March 31, 2024, there were no further significant changes in estimates.

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

2. Material Accounting Policies

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2023, except for the adoption of new standards effective as of Jan. 1, 2024.

A. Current Accounting Changes

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

In October 2022, the International Accounting Standards Board ("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.

B. Future Accounting Changes

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

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

3. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental attributes, leasing of power facilities and from asset optimization activities, which the Company disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

3 months ended March 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	5	70	112	3	—	—	190
Environmental attributes(1)	14	18	—	—	—	—	32
Revenue from contracts with customers	19	88	112	3	—	—	222
Revenue from leases(2)	—	—	7	—	—	—	7
Revenue from derivatives and other trading activities(3)	6	21	88	70	52	—	237
Revenue from merchant sales	83	20	222	144	—	—	469
Other(4)	4	4	4	—	—	—	12
Total revenue	112	133	433	217	52	—	947
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	14	18	—	3	—	—	35
Over time	5	70	112	—	—	—	187
Total revenue from contracts with customers	19	88	112	3	—	—	222

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.

(2) Total lease income from long-term contracts that meet the criteria of operating leases.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous revenues.

3 months ended March 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	4	59	99	3	—	—	165
Environmental attributes(1)	8	13	—	—	—	—	21
Revenue from contracts with customers	12	72	99	3	—	—	186
Revenue from leases(2)	—	—	8	—	—	—	8
Revenue from derivatives and other trading activities(3)	25	(1)	29	78	92	—	223
Revenue from merchant sales	86	34	357	186	—	—	663
Other(4)	2	5	2	—	—	—	9
Total revenue	125	110	495	267	92	—	1,089
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	8	13	—	3	—	—	24
Over time	4	59	99	—	—	—	162
Total revenue from contracts with customers	12	72	99	3	—	—	186

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.

(2) Total lease income from long-term contracts that meet the criteria of operating leases.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous revenues.

4. Expenses by Nature

Fuel, Purchased Power and Operations, Maintenance and Administration ("OM&A")

Fuel and purchased power and OM&A expenses are classified by nature as follows:

	2024		2023	
3 months ended March 31	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**109**	**—**	110	—
Coal fuel costs	**34**	**—**	54	—
Royalty, land lease, other direct costs	**8**	**—**	8	—
Purchased power	**172**	**—**	152	—
Salaries and benefits	**—**	**65**	1	64
Other operating expenses	**—**	**69**	—	60
Total	**323**	**134**	325	124

Carbon Compliance

As at March 31, 2024, the Company holds 791,374 emission credits in inventory that were purchased externally with a recorded book value of $39 million (Dec. 31, 2023 – 962,548 emission credits with a recorded book value of $45 million). The Company also has 2,901,154 (Dec. 31, 2023 – 3,121,837) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments which have no recorded book value.

Emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Alberta, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance in the year of settlement. The compliance price of carbon for the 2023 obligation to be settled in the current year was $65 per tonne and has increased to $80 per tonne in the current year.

5. Interest Expense

The components of interest expense are as follows:

3 months ended March 31	2024	2023
Interest on debt	**49**	50
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares[1]	**7**	7
Capitalized interest (Note 12)	**(14)**	(13)
Interest on lease liabilities	**2**	2
Credit facility fees, bank charges and other interest	**6**	8
Tax shield on tax equity financing	**—**	(1)
Accretion of provisions	**12**	14
Interest expense	**69**	74

(1) On Oct. 30, 2020, Brookfield invested $400 million in the Company in exchange for redeemable, retractable first preferred shares (Series I). The Series I Preferred Shares are accounted for as current debt and the exchangeable preferred share dividends are reported as interest expense. On April 24, 2024, the Company declared a dividend of $7 million in aggregate on the Series I Preferred Shares at the fixed rate of 1.740 per cent, per share, payable on May 31, 2024.

6. Income Taxes

The components of income tax expense are as follows:

3 months ended March 31	2024	2023
Current income tax expense	**27**	60
Deferred income tax expense related to the origination and reversal of temporary differences	**34**	49
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**(5)**	(1)
Reversal of write-down of unrecognized deferred income tax assets[1]	**(27)**	(59)
Income tax expense	**29**	49
Current income tax expense	**27**	60
Deferred income tax expense (recovery)	**2**	(11)
Income tax expense	**29**	49

(1) During the three months ended March 31, 2024, the Company recognized deferred tax assets of $27 million (March 31, 2023 - $59 million). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned US operations and other deductible differences.

7. Non-Controlling Interests

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

Subsidiary / Operation	NCI owner	NCI as at March 31, 2024	NCI as at Dec. 31, 2023	NCI as at March 31, 2023
TransAlta Cogeneration L.P.	Canadian Power Holdings Inc.	**49.99%**	49.99%	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	**17%**	17%	17%
TransAlta Renewables Inc.[1]	Public shareholders	**nil**	nil	39.9%

(1) Non-controlling interest from Jan. 1, 2023 to Oct. 4, 2023 was 39.9%.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a dual-fuel generating facility.

Kent Hills Wind LP owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick. Kent Hills Wind LP is a subsidiary of TransAlta Renewables Inc. ("TransAlta Renewables").

TransAlta Renewables owns a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Company.

On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates. TransAlta Renewables at March 31, 2024 and at Dec. 31, 2023, is a wholly owned subsidiary of the Company.

3 months ended March 31	2024	2023
Net earnings attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**16**	23
Kent Hills Wind LP[1]	**—**	N/A
TransAlta Renewables Inc.[1]	**N/A**	17
	16	40
Total comprehensive income attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**16**	23
Kent Hills Wind LP[1]	**—**	N/A
TransAlta Renewables Inc.[1]	**N/A**	21
	16	44
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**19**	51
Kent Hills Wind LP[1]	**—**	N/A
TransAlta Renewables Inc.[1]	**N/A**	25
	19	76

(1) 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. Subsequent to Oct. 5, 2023, no non-controlling interest exists for TransAlta Renewables. Prior to Oct 5, 2023, financial information related to the 17 per cent non-controlling interest in Kent Hills Wind LP was included in the financial information disclosed for TransAlta Renewables.

As at	March 31, 2024	Dec. 31, 2023
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**(75)**	(79)
Kent Hills Wind LP	**(49)**	(48)
	(124)	(127)
Non-controlling interests (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
Kent Hills Wind LP	**17.00**	17.00

8. Trade and Other Receivables and Accounts Payable

	March 31, 2024	Dec. 31, 2023
Trade accounts receivable	**467**	600
Collateral provided (Note 10)	**171**	145
Current portion of finance lease receivables (Note 11)	**21**	19
Loan receivable	**1**	1
Income taxes receivable	**30**	42
Trade and other receivables	**690**	807

	March 31, 2024	Dec. 31, 2023
Accounts payable and accrued liabilities	**603**	772
Interest payable	**21**	16
Collateral held (Note 10)	**50**	9
Accounts payable and accrued liabilities	**674**	797

9. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.

B. Fair Value of Financial Instruments

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy utilized by the Company are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. The Level III classification is the lowest level classification in the fair value hierarchy.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Company's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Company uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

There were no changes in the Company's valuation processes, valuation techniques and types of inputs used in the fair value measurements during the period. For additional information, please refer to Note 14 of the 2023 audited annual consolidated financial statements.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at March 31, 2024, are as follows: Level I – $5 million net liability (Dec. 31, 2023 – $13 million net liability), Level II – $94 million net liability (Dec. 31, 2023 – $244 million net liability) and Level III – $80 million net liability (Dec. 31, 2023 – $147 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2024, are primarily attributable to contract settlements and volatility in market prices across multiple markets on both existing contracts and new contracts.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the three months ended March 31, 2024 and 2023, respectively:

	3 months ended March 31, 2024			3 months ended March 31, 2023		
	Hedge[1]	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	**(147)**	**(147)**	(347)	(435)	(782)
Changes attributable to:						
Market price changes on existing contracts	—	**62**	**62**	(26)	106	80
Market price changes on new contracts	—	**3**	**3**	—	(4)	(4)
Contracts settled	—	**(3)**	**(3)**	118	135	253
Change in foreign exchange rates	—	**5**	**5**	1	—	1
Transfers out of Level III	—	—	—	—	11	11
Net risk management liabilities at end of period	—	**(80)**	**(80)**	(254)	(187)	(441)
Additional Level III information:						
Losses recognized in other comprehensive loss	—	—	—	(25)	—	(25)
Total gains (losses) included in earnings before income taxes	—	**70**	**70**	(118)	102	(16)
Unrealized gains included in earnings before income taxes relating to net liabilities held at period end	—	**67**	**67**	—	237	237

(1) The Company has a long-term fixed price power sale contract in the US for delivery of power. The fair value of this instrument was transferred out of Level III to Level II as at Dec. 31, 2023 as the forward price curve is now based on observable market prices for the remaining duration of the contract.

As at March 31, 2024, the total Level III risk management asset balance was $82 million (Dec. 31, 2023 – $56 million) and Level III risk management liability balance was $162 million (Dec. 31, 2023 – $203 million). The net risk management liabilities decreased mainly due to market price changes and settled contracts.

The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table.

These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

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

As at		March 31, 2024		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity**[1]
Coal transportation – US	Numerical derivative valuation	Volatility	80% to 120%	**+4**
		Rail rate escalation	zero to 10%	**-3**
Full requirements – Eastern US	Scenario analysis	Volume	98% to 108%	**+2**
		Cost of supply	Decrease of $3.20 per MWh or increase of $1.90 per MWh	**-2**
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	**+25**
		Illiquid future REC prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 9% increase	**-29**
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$68 or increase of C$5	**+49**
		Wind discounts	14% decrease or 5% increase	**-19**
Long-term wind energy sale - Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$1 or increase of US$2	**+67**
		Wind discounts	6% decrease or 2% increase	**-34**

(1) Sensitivity represents the total increase or decrease in recognized fair value that could arise from the use of the reasonably possible changes of all unobservable inputs.

As at		Dec. 31, 2023		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity**[1]
Coal transportation – US	Numerical derivative valuation	Volatility	80% to 120%	+6
		Rail rate escalation	zero to 10%	-4
Full requirements - Eastern US	Scenario analysis	Volume	96% to 104%	+3
		Cost of supply	Decrease of $2.30 per MWh or increase of $2.40 per MWh	-3
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+24
		Illiquid future REC prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 9% increase	-28
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$81 or increase of C$5	+65
		Wind discounts	16% decrease or 5% increase	-23
Long-term wind energy sale – Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease US$1 or increase of US$2	+81
		Wind discounts	5% decrease or 2% increase	-36

(1) Sensitivity represents the total increase or decrease in recognized fair value that would arise from the use of the reasonably possible changes of all unobservable inputs.

a. Coal Transportation – US

The Company has a coal rail transport agreement that includes an upside sharing mechanism until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the agreement.

b. Full Requirements – Eastern US

The Company has a portfolio of full requirement service contracts, whereby the Company agrees to supply specific utility customer needs with a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits ("RECs") and independent system operator costs. The contracts expire at the end of May 2025.

c. Long-Term Wind Energy Sale – Eastern US

The Company is party to a long-term contract for differences ("CFD") for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price, the customer pays the Company the difference and if the market price is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract matures in December 2034. The contract is accounted for as a derivative. Changes in fair value are presented in revenue.

d. Long-Term Wind Energy Sale – Canada

The Company is party to two Virtual Power Purchase Agreements ("VPPAs") for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind facility. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price the customer pays the Company the difference and if the pool price is higher than the fixed contract price the Company refunds the difference to the customer. The customers are also entitled to the physical delivery of environmental attributes. Both VPPAs commenced on commercial operation of the facility which was achieved in August 2023, and extend for a weighted average of approximately 17 years.

The energy components of these contracts are accounted for as derivatives. Changes in fair value are presented in revenue.

e. Long-Term Wind Energy Sale – Central US

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects. The VPPAs, together with the sale of electricity generated into the US Southwest Power Pool ("SPP") market at the relevant price nodes, achieve the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commenced on commercial operation of the facilities which was achieved on Jan. 1, 2024 for White Rock West and April 22, 2024 for White Rock East.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind power project. The VPPA, together with the sale of electricity generated into the SPP market at the relevant price node, achieve the fixed contract price per MWh. Under the VPPA, if the SPP pricing is lower than the fixed contract price, the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPA commences on commercial operation of the facility.

The energy components of these contracts are accounted for as derivatives. Changes in fair value are presented in revenue.

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net liability fair value of $3 million as at March 31, 2024 (Dec. 31, 2023 – $19 million net asset) are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value(1)		Total carrying value(1)
	Level II	Total	
Exchangeable securities — March 31, 2024	**720**	**720**	**745**
Long-term debt — March 31, 2024	**3,064**	**3,064**	**3,312**
Loan receivable — March 31, 2024	**26**	**26**	**26**
Exchangeable securities — Dec. 31, 2023	718	718	744
Long-term debt — Dec. 31, 2023	3,104	3,104	3,323
Loan receivable — Dec. 31, 2023	26	26	26

(1) Includes current portion.

The fair values of the Company's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 9 above for the fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions are identified that are substantially the same, or a valuation technique is identified that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss) and a reconciliation of changes is as follows:

3 months ended March 31	2024	2023
Unamortized net gain (loss) at beginning of period	**3**	(213)
New inception gains	**4**	2
Change in foreign exchange rates	**(1)**	—
Amortization recorded in net earnings during the period	**8**	(7)
Unamortized net gain (loss) at end of period	**14**	(218)

10. Risk Management Activities

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and its risk tolerance. For additional information on the Company's Risk Management Activities please refer to Note 15 of the 2023 audited annual consolidated financial statements.

B. Net Risk Management Assets and Liabilities

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

As at March 31, 2024

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**(58)**	**23**	**(35)**
Long-term	**(43)**	**(101)**	**(144)**
Net commodity risk management liabilities	**(101)**	**(78)**	**(179)**
Other			
Current	**—**	**(2)**	**(2)**
Long-term	**—**	**(1)**	**(1)**
Net other risk management liabilities	**—**	**(3)**	**(3)**
Total net risk management liabilities	**(101)**	**(81)**	**(182)**

As at Dec. 31, 2023

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	(125)	(53)	(178)
Long-term	(80)	(146)	(226)
Net commodity risk management liabilities	(205)	(199)	(404)
Other			
Current	—	15	15
Long-term	—	4	4
Net other risk management assets	—	19	19
Total net risk management liabilities	(205)	(180)	(385)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk Management – Proprietary Trading

The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

A Value at Risk ("VaR") measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at March 31, 2024, associated with the Company's proprietary trading activities was $3 million (Dec. 31, 2023 – $4 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Company's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Company's reported net earnings.

VaR at March 31, 2024, associated with the Company's commodity derivative instruments used in generation hedging activities was $15 million (Dec. 31, 2023 – $23 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at March 31, 2024, associated with these transactions was $17 million (Dec. 31, 2023 – $16 million). For the market risk related to long-term wind energy sales, which are backed by physical assets to effectively reduce our market risk, refer to the Level III measurements table and the related unobservable inputs and sensitivities in Note 9(B)(II).

II. Credit Risk

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at March 31, 2024:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables[1]	92	8	100	**690**
Long-term finance lease receivable	100	—	100	**211**
Risk management assets[1]	61	39	100	**375**
Loans receivable[2]	—	100	100	**26**
Total				**1,302**

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

(2) Includes $26 million loans receivable included within other assets with counterparties that have no external credit rating.

The Company did not have material expected credit losses as at March 31, 2024. The Company's maximum exposure to credit risk at March 31, 2024, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the condensed consolidated statements of financial position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at March 31, 2024, was $33 million (Dec. 31, 2023 – $23 million).

III. Liquidity Risk

The Company has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for September 2024. Our highly diversified asset portfolio, by both fuel type and operating region, and our long-term contracted asset base provide stability in our cash flows.

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes.

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

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Bank overdraft	2	—	—	—	—	—	2
Accounts payable and accrued liabilities	674	—	—	—	—	—	674
Long-term debt[1]	496	141	142	152	161	2,257	3,349
Exchangeable securities[2]	—	—	—	—	—	750	750
Commodity risk management liabilities	8	90	2	6	6	67	179
Other risk management liabilities	2	1	—	—	—	—	3
Lease liabilities	3	4	4	4	4	126	145
Interest on long-term debt and lease liabilities[3]	152	168	161	154	145	727	1,507
Interest on exchangeable securities[2][3]	40	53	53	53	53	11	263
Dividends payable	18	—	—	—	—	—	18
Total	**1,395**	**457**	**362**	**369**	**369**	**3,938**	**6,890**

(1) Excludes impact of hedge accounting and derivatives.

(2) Cash payment may occur after Dec. 31, 2028 if exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). TransAlta has the right after Dec. 31, 2028, to redeem for cash all or any portion of the exchangeable securities for the original subscription price, plus any accrued but unpaid interest or dividends payable, provided the minimum proceeds to Brookfield for each redemption (other than the final redemption) is not less than $100 million and provided all exchangeable securities must be redeemed within 36 months of the first optional redemption. The exchangeable securities are classified as current as they can be exchanged at Brookfield's option, at the earliest, on Jan. 1, 2025, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. Refer to Note 2 for more details.

(3) Not recognized as a financial liability on the condensed consolidated statements of financial position.

D. Collateral

I. Financial Assets Provided as Collateral

At March 31, 2024, the Company provided $171 million (Dec. 31, 2023 – $145 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included within trade and other receivables in the condensed consolidated statements of financial position. At March 31, 2024, the Company provided $20 million (Dec. 31, 2023 - $19 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At March 31, 2024, the Company held $50 million (Dec. 31, 2023 – $9 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the condensed consolidated statements of financial position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At March 31, 2024, the Company had posted collateral of $458 million (Dec. 31, 2023 – $392 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $126 million (Dec. 31, 2023 – $154 million) of collateral to its counterparties.

11. Finance Lease Receivables

Amounts receivable under the Company's finance leases include the Mount Keith 132kV expansion (2024), Northern Goldfields solar facilities (2024 and 2023), the Poplar Creek cogeneration facility (2024 and 2023), and are as follows:

	March 31, 2024		Dec. 31, 2023	
As at	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**34**	**33**	28	28
Second to fifth years inclusive	**135**	**116**	112	98
More than five years	**168**	**83**	117	64
	337	**232**	257	190
Less: unearned finance lease income	**105**	**—**	67	—
Total finance lease receivables	**232**	**232**	190	190

Included in the condensed consolidated statements of financial position as:		
Current portion of finance lease receivables (Note 8)	**21**	19
Long-term portion of finance lease receivables	**211**	171
Total finance lease receivables	**232**	190

In the first quarter of 2024, the Mount Keith 132kV expansion was completed. As a result, the Company derecognized assets under construction and recognized a finance lease receivable of $48 million.

12. Property, Plant and Equipment

During the three months ended March 31, 2024, the Company had additions of $68 million, mainly related to assets under construction for the White Rock wind projects, the Horizon Hill wind project and planned major maintenance. As outlined in Note 11, $48 million related to the Mount Keith 132kV expansion was derecognized from assets under construction and recognized as a finance lease receivable.

During the three months ended March 31, 2024, the Company capitalized $14 million (March 31, 2023 – $13 million) of interest to property, plant and equipment at a weighted average rate of 6.5 per cent (March 31, 2023 – 6.1 per cent).

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

A. Amounts Outstanding Related to Credit Facilities

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

As at March 31, 2024		Utilized			
Credit Facilities	**Facility size**	**Outstanding letters of credit[(1)]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
TransAlta syndicated credit facility	1,950	492	—	1,458	Q2 2027
TransAlta bilateral credit facilities	240	181	—	59	Q2 2025
TransAlta Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**673**	**400**	**1,517**	
Non-Committed					
TransAlta demand facilities	400	201	—	199	N/A
Total Non-Committed	**400**	**201**	**—**	**199**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At March 31, 2024, TransAlta provided cash collateral of $171 million.

The credit facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business. The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. $201 million letters of credit are issued from non-committed demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities. In addition to the net $1.3 billion of committed capacity available under the credit facilities, the Company also had $417 million of available cash and cash equivalents, net of bank overdraft.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at March 31, 2024, the Company was in compliance with all debt covenants.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd and Windrise Wind LP non-recourse bonds and the TransAlta OCP LP bond, with a total carrying value of $1.6 billion as at March 31, 2024 (Dec. 31, 2023 – $1.7 billion) are subject to customary financing conditions and covenants that may restrict the Company’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the first quarter of 2024, with the exception of Kent Hills Wind LP. Kent Hills Wind LP cannot make any distributions to its partners until the independent engineer's report has been finalized and the the debt service coverage ratio is met. The funds in the entities will remain restricted until the next debt service coverage test can be performed in the second quarter of 2024. At March 31, 2024, $88 million (Dec. 31, 2023 – $79 million) of cash was subject to these financial restrictions.

At March 31, 2024, $4 million (AU$4 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.

C. Restricted Cash

As at March 31, 2024, the Company had nil (Dec. 31, 2023 – $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund scheduled future debt repayments. The Company also had $46 million (Dec. 31, 2023 – $52 million) of restricted cash related to the TEC Hedland Pty Ltd bond. These cash reserves are required to be held under commercial arrangements and for debt service, which may be replaced by letters of credit in the future. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

14. Common Shares

A. Issued and Outstanding

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

	2024		2023	
3 months ended March 31	**Common shares (millions)**	**Amount**	**Common shares (millions)**	**Amount**
Issued and outstanding, beginning of period	**306.9**	**3,285**	268.1	2,863
Reversal (provision) for repurchase of common shares under ASPP	**1.7**	**19**	—	—
Purchased and cancelled under the NCIB[1]	**(3.5)**	**(37)**	(3.2)	(34)
Share-based payment plans	**0.7**	**10**	0.8	5
Stock options exercised	**0.7**	**3**	0.3	2
Issued and outstanding, end of period, prior to ASPP	**306.5**	**3,280**	266.0	2,836
Provision for repurchase of common shares under ASPP	**(2.5)**	**(22)**	(3.0)	(37)
Issued and outstanding, end of period	**304.0**	**3,258**	263.0	2,799

(1) Shares purchased by the Corporation under the NCIB (as defined below) are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings (deficit).

B. Normal Course Issuer Bid ("NCIB") Program

The effects of the Company's purchase and cancellation of common shares during the period are as follows:

3 months ended March 31	**2024**	**2023**
Total shares purchased[1]	**3,460,300**	3,169,300
Average purchase price per share	**9.36**	11.23
Total cost (millions)	**32**	36
Book value of shares cancelled	**37**	34
Amount recorded in deficit	**5**	(2)

(1) The three months ended March 31, 2024 include 300,000 shares (March 31, 2023 - 312,400 shares) that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. As a result, $2 million (2023 - $2 million) was paid subsequent to period end.

On March 19, 2024, the Company entered into an Automatic Share Purchase Plan ("ASPP") which permits an independent broker to repurchase shares under the NCIB during the first quarter blackout period through to the end of the ASPP. The Company has recognized a provision of $22 million for the repurchase of 2.5 million common shares under the ASPP within accounts payable and accrued liabilities as at March 31, 2024, as an estimate of the maximum number of shares that could be repurchased during the blackout period.

C. Dividends

On April 24, 2024, the Company declared a quarterly dividend of $0.06 per common share, payable on July 1, 2024.

There have been no other transactions involving common shares between the reporting date and the date of completion of these condensed consolidated financial statements.

15. Preferred Shares

A. Issued and Outstanding

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

	March 31, 2024		Dec. 31, 2023	
Series[1]	**Number of shares (millions)**	**Amount**	**Number of shares (millions)**	**Amount**
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	10.0	243
Series D	**1.0**	**26**	1.0	26
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of period	**38.6**	**942**	38.6	942

(1) The Series I Preferred Shares are accounted for as long-term debt and the exchangeable preferred share dividends are reported as interest expense.

B. Dividends

On April 24, 2024, the Company declared a quarterly dividend of \$0.17981 per share on the Series A preferred shares, \$0.43579 per share on the Series B preferred shares, \$0.36588 per share on the Series C preferred shares, \$0.50230 per share on the Series D preferred shares, \$0.43088 per share on the Series E preferred shares and \$0.31175 per share on the Series G preferred shares, payable on June 30, 2024.

16. Commitments and Contingencies

Commitments

The Company has not incurred any additional contractual commitments in the three months ended March 31, 2024, either directly or through its interests in joint operations and joint ventures. Refer to the commitments disclosed elsewhere in the financial statements and those in Note 36 of the 2023 audited annual consolidated 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.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required. 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 three months ended March 31, 2024.

17. Segment Disclosures

A. Description of Reportable Segments

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM"), reviews the Company's segments to make operating decisions and assess performance. The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings (loss) reported under IFRS.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

3 months ended March 31, 2024	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	112	139	433	217	52	—	953	(6)	—	947
Reclassifications and adjustments:										
Unrealized mark-to-market gain	(5)	(21)	(91)	(6)	(3)	—	(126)	—	126	—
Realized gain (loss) on closed exchange positions	—	—	8	(1)	(19)	—	(12)	—	12	—
Decrease in finance lease receivable	—	1	4	—	—	—	5	—	(5)	—
Finance lease income	—	1	1	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	107	120	354	210	30	—	821	(6)	132	947
Fuel and purchased power	6	9	142	166	—	—	323	—	—	323
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	6	9	141	166	—	—	322	—	1	323
Carbon compliance	—	—	40	—	—	—	40	—	—	40
Gross margin	101	111	173	44	30	—	459	(6)	131	584
OM&A	13	20	46	18	10	28	135	(1)	—	134
Taxes, other than income taxes	1	4	3	—	—	—	8	—	—	8
Net other operating income	—	(2)	(10)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA[2]	87	89	134	26	20	(28)	328			
Equity income										1
Finance lease income										2
Depreciation and amortization										(124)
Asset impairment charges										(1)
Interest income										7
Interest expense										(69)
Foreign exchange loss and other										(3)
Earnings before income taxes										267

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

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

3 months ended March 31, 2023	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	125	115	495	267	92	—	1,094	(5)	—	1,089
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(1)	—	(64)	(14)	16	—	(63)	—	63	—
Realized gain (loss) on closed exchange positions	—	—	(13)	—	(55)	—	(68)	—	68	—
Decrease in finance lease receivable	—	—	13	—	—	—	13	—	(13)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	124	115	435	253	53	—	980	(5)	114	1,089
Fuel and purchased power	5	9	130	181	—	—	325	—	—	325
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	9	129	181	—	—	324	—	1	325
Carbon compliance	—	—	32	—	—	—	32	—	—	32
Gross margin	119	106	274	72	53	—	624	(5)	113	732
OM&A	12	17	41	17	14	24	125	(1)	—	124
Taxes, other than income taxes	1	3	4	1	—	—	9	—	—	9
Net other operating income	—	(2)	(11)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA[2]	106	88	240	54	39	(24)	503			
Equity income										2
Finance lease income										4
Depreciation and amortization										(176)
Asset impairment reversals										3
Interest income										15
Interest expense										(74)
Foreign exchange loss										(3)
Earnings before income taxes										383

(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.

18. Related-Party Transactions

Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the Investment Agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company and, as such, they are considered associates of the Company.

The Company may, in the normal course of operations, enter into transactions on market terms with associates that have been measured at exchange value and recognized in the condensed consolidated financial statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate. Refer to Note 25 and 35 of the 2023 audited annual consolidated financial statements.

Transactions with Brookfield include the following:

	3 months ended March 31	
	2024	**2023**
Power sales	**21**	42
Purchased power	**3**	1

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. authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets

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

Alberta Thermal

The business segment previously disclosed as Canadian Coal has been renamed to reflect the ongoing conversion of the boilers to burn gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale Mine.

Ancillary Services

As defined by the *Electric Utilities Act*, 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.

Disclosure Controls and Procedures (DC&P)

Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Company or submitted under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Dispatch optimization

Purchasing power to fulfill contractual obligations, when economical.

Economic Dispatch

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

Emissions Performance Standards (EPS)

Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

EPCs

Emission Performance Credits.

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.

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.