TRANSALTA CORPORATION

Management's Discussion and Analysis

Third Quarter Report for 2023

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

Table of Contents

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2023 and 2022, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A ("2022 Annual MD&A") contained within our 2022 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refers to TransAlta Corporation and its subsidiaries. Our unaudited interim condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") 34 Interim Financial Reporting for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Sept. 30, 2023. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Nov. 6, 2023. Additional information respecting TransAlta, including our Annual Information Form ("AIF") for the year ended Dec. 31, 2022, 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 ("US") securities laws, including the United States 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 assumptions were 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 that 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 acquisition of Heartland (as defined below) and its entire business operations in Alberta and British Columbia, including the ability to obtain regulatory approval and the timing thereof; the annual average EBITDA to be generated from the Heartland acquisition and other benefits expected to arise from such transaction; the rehabilitation of the Kent Hills 1 and 2 wind facilities, including, the timing and cost of such rehabilitation; the seasonality of wind and hydro resources; the Company’s 2023 Outlook, including Adjusted EBITDA, free cash flow, annualized dividend per share, sustaining capital and energy marketing gross margin; our Clean Electricity Growth Plan and ability to achieve the target of 2 gigawatts ("GW") of incremental clean electricity capacity with an estimated capital investment of $3.6 billion that is expected to deliver incremental average annual EBITDA of $315 million; the expansion of the Company's early stage development pipeline to 5 GW; the 418 MW of advanced-stage projects, including the target completion date, estimated spend and estimated average annual EBITDA; the Company's projects under construction, including capital costs, the timing of commercial operations, expected annual EBITDA, including in respect of the Horizon Hill wind project, the White Rock wind projects, Northern Goldfields solar project, and the Mount Keith 132kV transmission expansion; the development of the early-stage Tent Mountain Renewable Energy Complex; the proportion of EBITDA to be generated from renewable sources by the end of 2025; 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; regulatory developments and their expected impact on the Company; expectations regarding refinancing debt; 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 Alberta spot prices of $150 to $170 per MWh in 2023, Mid-Columbia spot prices of US$90 to US$100 per MWh in 2023, and AECO gas prices of $2.50 per GJ in 2023; hedged volumes and prices in 2023; sustaining capital of $140 million - $170 million in 2023; Energy Marketing gross margin of $130 million - $150 million in 2023; no significant changes to gas commodity prices and transport costs; no significant changes to the 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; operational risks involving Heartland's facilities; supply chain disruptions impacting major maintenance and growth projects; failure to obtain necessary regulatory approvals in a timely fashion, or at all; inability to economically or technologically advance the Battle River Carbon Hub Project to final investment decision or commercial operation; 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 as it pertains to increased capital costs, permitting, 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; impact of energy transition on our business; impairments and/or write-downs 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; 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, including as it applies to the rehabilitation and replacement of turbine foundations of the Kent Hills 1 and 2 wind facilities; general economic conditions globally, including deterioration of equity markets, increasing interest rates or rising inflation; failure to meet financial expectations; general domestic and international economic and political developments; armed hostilities, including the war in Ukraine and Israel and associated impacts; the threat of terrorism; adverse diplomatic developments or other similar events that could adversely affect our business; 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 our 2022 Annual MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2022.

Readers are urged to consider these factors carefully in 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

Portfolio of Assets

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 112 years of operating experience. We own, operate and manage a geographically diversified portfolio of assets utilizing a broad range of input resources that includes water, wind, solar, natural gas and thermal coal. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.

During the third quarter of 2023, the Garden Plain wind facility was commissioned. The completion of the Garden Plain wind facility added 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation and PepsiCo Canada, with a weighted average contract life of approximately 17 years.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of Sept. 30, 2023:

As at Sept. 30, 2023		Hydro	Wind and Solar	Gas	Energy Transition	Total
Alberta	Gross installed capacity (MW)(1)	834	766	1,960	—	3,560
	Number of facilities	17	14	7	—	38
	Weighted average contract life (years)(2)(3)(4)	—	8	1	—	2
Canada, Excluding Alberta	Gross installed capacity (MW)(1)	88	751	645	—	1,484
	Number of facilities	7	9	3	—	19
	Weighted average contract life (years)(3)	11	11	9	—	10
US	Gross installed capacity (MW)	—	519	29	671	1,219
	Number of facilities	—	7	1	2	10
	Weighted average contract life (years)(3)	—	10	2	2	6
Australia	Gross installed capacity (MW)	—	—	450	—	450
	Number of facilities	—	—	6	—	6
	Weighted average contract life (years)(3)	—	—	15	—	15
Total	**Gross installed capacity (MW)**	922	2,036	3,084	671	6,713
	Number of facilities	24	30	17	2	73
	Weighted average contract life (years)(3)	1	10	5	2	5

(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; Gas segment includes 100 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.*

(2) *The weighted average contract life for Hydro and certain gas and wind assets in Alberta are nil as they are operating primarily on a merchant basis in the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for more information.*

(3) *For power generated under long-term power purchase agreements ("PPAs"), power hedge contracts and short-term and long-term industrial contracts, the PPAs have a weighted-average remaining contract life based on long-term average gross installed capacity.*

(4) *The weighted-average remaining contract life is related to the contract period for Garden Plain (130 MW), McBride Lake (38 MW), Windrise (206 MW), Poplar Creek (115 MW) and Fort Saskatchewan (71 MW), with the remaining wind and gas facilities operated on a merchant basis in the Alberta market.*

TransAlta fully consolidates TransAlta Renewables as a subsidiary of the Company as TransAlta has control through its majority ownership (60.1 per cent) of TransAlta Renewables. The table above includes the facilities owned by TransAlta Renewables and reflects the gross installed capacity and weighted average contract life of those facilities as if TransAlta directly owned these facilities. The acquisition of TransAlta Renewables, that occurred in the fourth quarter of 2023, will have no impact to the consolidated information presented in the table above; however, the acquisition will increase TransAlta's proportional ownership interest of the assets by approximately 1.2 GW of wind, solar and gas.

Highlights

Consolidated Financial Highlights

(in millions of Canadian dollars except where noted)	3 months ended Sept. 30 2023	3 months ended Sept. 30 2022	9 months ended Sept. 30 2023	9 months ended Sept. 30 2022
Adjusted availability (%)	**91.9**	93.8	**89.4**	90.1
Production (GWh)	**5,678**	5,432	**16,246**	15,253
Revenues	**1,017**	929	**2,731**	2,122
Fuel and purchased power	**269**	348	**782**	817
Carbon compliance	**28**	23	**85**	51
Operations, maintenance and administration	**131**	135	**389**	364
Adjusted EBITDA(1)	**453**	555	**1,343**	1,093
Earnings before income taxes	**453**	126	**915**	346
Net earnings attributable to common shareholders	**372**	61	**728**	167
Cash flow from operating activities	**681**	204	**1,154**	526
Funds from operations(1)	**357**	488	**1,122**	887
Free cash flow(1)	**228**	393	**769**	646
Net earnings per share attributable to common shareholders, basic and diluted	**1.41**	0.23	**2.75**	0.62
Dividends declared per common share(2)	**0.0550**	0.0500	**0.1100**	0.1000
Dividends declared per preferred share(2)	**0.3316**	0.2896	**0.6627**	0.5453
Funds from operations per share(1)(3)	**1.36**	1.80	**4.23**	3.27
Free cash flow per share(1)(3)	**0.87**	1.45	**2.90**	2.38

As at	Sept. 30, 2023	Dec. 31, 2022
Total assets	**9,520**	10,741
Total consolidated net debt(1)(4)	**2,651**	2,854
Total long-term liabilities	**5,230**	5,864
Total liabilities	**6,857**	8,752

(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) Weighted average of the Series A, B, C, D, E and G preferred share dividends declared. Dividends declared vary period over period due to timing of dividend declarations and quarterly floating rates.

(3) 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. The weighted average number of common shares outstanding for the three and nine months ended Sept. 30, 2023, was 263 million shares and 265 million shares, respectively (Sept. 30, 2022 – 271 million for both periods). Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(4) Total consolidated net debt includes long-term debt, including the current portion, amounts due under credit facilities, exchangeable debentures, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash on our subsidiary TransAlta OCP LP ("TransAlta OCP") and the fair value of economic hedging instruments on debt. Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

During the third quarter of 2023, the Company continued to demonstrate strong performance in its Alberta Electricity Portfolio, led by the Alberta Gas and Hydro segments, which continue to benefit from higher than expected energy and ancillary service pricing in the Alberta market, lower than expected natural gas prices and favourable hedging impacts resulting in higher than expected gross margins.

For the three months ended Sept. 30, 2023, the Company's results were lower than compared to the same period in 2022, but higher than expected. For the three months ended Sept. 30, 2022, the Company experienced above normal temperatures increasing the demand for electricity, periods of significant planned and unplanned thermal and transmission outages, both of which created stronger than normal spot market conditions in the Alberta energy and ancillary market.

For the nine months ended Sept. 30, 2023, the Company demonstrated stronger performance compared to the same period in 2022, mainly due to the continued strong market conditions in Alberta, higher hedged prices, higher hedged volumes and lower realized gas prices in the Gas segment and higher merchant pricing and production in the Energy Transition segment, partially offset by lower wind resources. For the three and nine months ended Sept. 30, 2023, the Energy Marketing segment's performance was lower compared to the same periods in 2022 due to timing of realized settlements, but in line with segment expectations.

Adjusted availability for the three and nine months ended Sept. 30, 2023, was 91.9 per cent and 89.4 per cent, respectively, compared to 93.8 per cent and 90.1 per cent, respectively, for the same periods in 2022. Adjusted availability for the three months ended Sept. 30, 2023 decreased primarily due to planned outages in the Gas segment and unplanned outages in the Energy Transition segment, partially offset by the partial return to service of the Kent Hills facilities. Adjusted availability for the nine months ended Sept. 30, 2023, was further impacted by planned outages in the Hydro segment.

Production for the three months ended Sept. 30, 2023, was 5,678 gigawatt hours ("GWh") compared to 5,432 GWh for the same period in 2022. The increase in production was primarily due to higher dispatch in Alberta and higher production in Ontario for the Gas segment. Hydro production for the three months ended was lower compared to the same period in 2022 due to higher water resource from delayed spring runoff in the third quarter of 2022 and lower than average water resource in the third quarter of 2023. Production for the nine months ended Sept. 30, 2023, was 16,246 GWh compared to 15,253 GWh for the same period in 2022. The increase in production was primarily due to stronger market conditions in Alberta and the Pacific Northwest in the Gas and Energy Transition segments, partially offset by lower production in the Wind and Solar segments due to lower wind and solar resources in all regions. Both the three and nine months ended Sept. 30, 2023, benefited from the addition of the Garden Plain wind facility.

Revenues for the three and nine months ended Sept. 30, 2023, increased by $88 million and $609 million, respectively, compared to the same periods in 2022. Revenues for the three months ended Sept. 30, 2023, increased mainly as a result of stronger market conditions with higher dispatch from our Alberta merchant gas assets and higher unrealized mark-to-market gains across the segments, partially offset by lower realized energy prices within the Alberta electricity market, lower realized ancillary service prices, lower ancillary service volumes and a decrease in production within the Hydro segment. For the nine months ended, Sept. 30, 2023, revenues were favourably impacted by the higher production from our gas assets and higher merchant pricing and higher production in the Energy Transition segment. For both the three and nine months ended Sept. 30, 2023, Energy Marketing revenues were higher mainly due to short-term trading of both physical and financial power and gas products across all North American deregulated markets.

Fuel and purchased power costs for the three and nine months ended Sept. 30, 2023, decreased by $79 million and $35 million, respectively, compared to the same periods in 2022, benefiting from lower natural gas commodity prices and higher hedged gas volumes in the Gas segment partially offset by higher fuel usage in the Gas and Energy Transition segments. The three months ended Sept. 30, 2023, further benefited from lower purchased power costs while the nine months ended Sept. 30, 2023, experienced higher purchased power costs incurred to meet contractual obligations during unplanned outages in the Energy Transition segment.

Carbon compliance costs for the three and nine months ended Sept. 30, 2023, increased by $5 million and $34 million, respectively, compared to the same periods in 2022, primarily due to an increase in the carbon price per tonne and higher production in the Gas segment. Carbon compliance costs for the nine months ended Sept. 30, 2023, increased compared to the same period in 2022, as a result of the utilization of emission credits in the the second quarter of 2022 to settle a portion of our GHG obligation.

Operations, maintenance and administration ("OM&A") expenses for the three months ended Sept. 30, 2023, decreased by $4 million compared to the same period in 2022, primarily due to incentive accruals adjustments, partially offset by higher spending on strategic and growth initiatives, increased costs due to inflationary pressures, and higher insurance costs. OM&A expenses for the nine months ended Sept. 30, 2023, increased by $25 million compared to the same period in 2022, primarily due to higher spending on strategic and growth initiatives, increased costs due to inflationary pressures, higher insurance costs and higher performance-related incentive accruals.

Adjusted EBITDA for the three months ended Sept. 30, 2023, exceeded our expectations for the period; however, decreased by $102 million compared to the same period in 2022. Energy prices and ancillary service prices for three months ended Sept. 30, 2023 were higher than our revised expected full year financial guidance provided in the second quarter of 2023. They were, however, lower than the comparative period due to the exceptional prices experienced in 2022 impacting adjusted EBITDA in both the Gas and Hydro segments. The Hydro segment's adjusted EBITDA was further impacted by higher production due to higher water resource in 2022 from a delayed spring runoff. These decreases to adjusted EBITDA were further impacted by lower results in the Energy Marketing segment due to adjustments to revenues to account for the timing of realized gains and losses on closed exchange positions and unrealized mark-to-market gains and losses and lower merchant pricing in the Energy Transition segments, partially offset by the higher production in the Gas segment. For the nine months ended Sept. 30, 2023, adjusted EBITDA increased by $250 million, compared to the same period in 2022, largely due to higher realized prices and production from the gas facilities, lower natural gas prices and higher revenue in the Energy Transition segment due to higher merchant pricing and higher production. These increases were partially offset by higher carbon compliance costs in the Gas segment, higher OM&A and lower revenues in the Wind and Solar and Energy Marketing segments. Changes in segmented adjusted EBITDA are discussed in the Segmented Financial Performance and Operating Results section of this MD&A.

Earnings before income taxes for the three and nine months ended Sept. 30, 2023, increased by $327 million and $569 million, respectively, compared to the same periods in 2022. **Net earnings attributable to common shareholders** for the three and nine months ended Sept. 30, 2023, were $372 million and $728 million compared to $61 million and $167 million for the same periods in 2022. For the three and nine months ended Sept. 30, 2023, the Company benefited from higher revenues net of unrealized gains and losses from risk management activities and lower natural gas commodity prices, partially offset by higher carbon compliance costs. The Company also benefited from higher asset impairment reversals and lower net interest expense, partially offset by higher net earnings allocated to non-controlling interests. Depreciation decreased in the three months ended Sept. 30, 2023, due to the extension of useful lives on certain facilities, but was higher for the nine months ended Sept. 30, 2023, compared to the same period in 2022, due to the acceleration of useful lives on certain facilities in the prior period. The nine months ended Sept. 30, 2023, also benefited from lower income tax expense, partially offset by higher OM&A expenses.

Cash flow from operating activities for the three and nine months ended Sept. 30, 2023, increased by $477 million and $628 million, respectively, compared with the same periods in 2022, primarily due to higher revenues net of unrealized gains and losses from risk management activities, lower fuel and purchased power and favourable changes in working capital. This was partially offset by higher carbon compliance costs and for the nine months ended Sept. 30, 2023, higher OM&A.

FCF, one of the Company's key financial metrics, totaled $228 million and $769 million, respectively, for the three and nine months ended Sept. 30, 2023 compared to $393 million and $646 million, respectively, in the same periods in 2022. For the three months ended Sept. 30, 2023, this represented a decrease of $165 million, primarily due to lower adjusted EBITDA, higher current income tax expense, higher distributions paid to subsidiaries' non-controlling interests and higher sustaining capital expenditures. For the nine months ended Sept. 30, 2023, FCF increased by $123 million, primarily due to higher adjusted EBITDA, lower interest expense mainly driven by higher interest income due to higher interest rates and higher interest capitalized on construction capital expenditures. This was partially offset by higher distributions paid to subsidiaries' non-controlling interests, higher sustaining capital expenditures and higher current income tax expense compared to 2022.

Significant and Subsequent Events

TransAlta to Acquire Heartland Generation from Energy Capital Partners

On Nov. 2, 2023, the Company announced that it had entered into a definitive share purchase agreement with an affiliate of Energy Capital Partners, the parent of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, "Heartland"), pursuant to which TransAlta will acquire Heartland and its entire business operations in Alberta and British Columbia. The acquisition will add 10 facilities to TransAlta’s fleet, totalling 1,844 MW of new capacity. Heartland owns and operates generation assets consisting of 507 MW of cogeneration, 387 MW of contracted and merchant peaking generation, 950 MW of gas-fired thermal generation, transmission capacity and a development pipeline that includes the 400 MW Battle River Carbon Hub. The transaction is expected to close in the first half of 2024, subject to customary closing conditions, including receipt of regulatory approvals.

The purchase price for the acquisition is $390 million, subject to working capital and other adjustments, as well as the assumption of $268 million of low-cost debt. The Company will finance the transaction using cash on hand and draws on its credit facilities.

The assets are expected to add approximately $115 million of average annual EBITDA including synergies. Approximately, 55 per cent of revenues are under contract with high creditworthy counterparties, which have a weighted-average remaining contract life of 16 years. Corporate pre-tax synergies are expected to exceed $20 million annually.

The acquisition will competitively position the Company in response to the changing dynamics in Alberta given the expected significant increase in renewables and other large baseload generation coming online in the next several years in the highly dynamic and shifting electricity landscape in the province. The Clean Electricity Growth Plan continues to be at the heart of our strategy and is dedicated to meeting the future needs of our customers with clean electricity solutions.

TransAlta Corporation Completes Acquisition of TransAlta Renewables Inc.

On Oct. 5, 2023, the Company announced the completion of the acquisition of TransAlta Renewables pursuant to the terms of the previously announced arrangement agreement between the parties ("the Arrangement"). TransAlta acquired all of the outstanding common shares of TransAlta Renewables ("RNW Shares") not already owned, directly or indirectly, by TransAlta and certain of its affiliates, resulting in TransAlta Renewables becoming a wholly owned subsidiary of the Company. Prior to the Arrangement, TransAlta and its affiliates collectively held 160,398,217 RNW Shares, representing 60.1 per cent of the issued and outstanding RNW Shares, with the remaining 106,510,884 RNW Shares held by TransAlta Renewables shareholders ("RNW Shareholders") other than TransAlta and its affiliates.

The Arrangement was approved by RNW Shareholders at a special meeting of shareholders held on Sept. 26, 2023, and by the Court of King’s Bench of Alberta on Oct. 4, 2023. The consideration paid totaled $1.3 billion which consisted of $800 million of cash and approximately 46 million common shares of the Company.

The closing of the acquisition of TransAlta Renewables represents a key milestone for the Company and the simplified and unified corporate structure positions it well for future success. The combined company will unify our assets, capital, and capabilities to enhance cash flow predictability while enhancing our ability to realize future growth.

The RNW Shares were delisted from the Toronto Stock Exchange ("TSX"). Common shares of the Company will continue to trade on both the New York Stock Exchange ("NYSE") and the TSX under the symbols "TAC" and "TA", respectively.

TransAlta Tops List of Newsweek's World's Most Trustworthy Companies for 2023

On Sept. 14, 2023, the Company announced that it ranked first on Newsweek's inaugural “World's Most Trustworthy Companies 2023” list for the Energy and Utilities category. The list identifies the top 1,000 companies in 21 countries and across 23 industries. Newsweek’s 2023 World’s Most Trustworthy Companies have been chosen based on a holistic approach to evaluating trust across three pillars of public trust – customer, investor and employee. The list was compiled based on an extensive survey of over 70,000 participants, gathering 269,000 evaluations of companies that people trust as a customer, as an investor and as an employee.

Garden Plain Wind Facility Reaches Commercial Operations

In August 2023, the Garden Plain wind facility was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation and PepsiCo Canada, with a weighted average contract life of approximately 17 years.

Normal Course Issuer Bid

On May 26, 2023, the TSX accepted the notice filed by the Company to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.29 per cent of its public float of common shares as at May 17, 2023. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2023 and ends on May 30, 2024, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Company's election.

The NCIB provides the Company with a capital allocation alternative with a view to ensuring long-term shareholder value. TransAlta's Board of Directors and management believe that, from time to time, the market price of the common shares might not be reflective of the underlying value and purchases of common shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

Annual Shareholder Meeting

On April 28, 2023, the Company held its annual meeting of shareholders. All director nominees were elected to the Board, including Candace MacGibbon, a new member to the Board. The Company also received strong support on all other items of business, including say-on-pay and an amendment to the Company's Share Unit Plan.

Tent Mountain Pumped Hydro Development Project

On April 24, 2023, the Company acquired a 50 per cent interest in the Tent Mountain Renewable Energy Complex ("Tent Mountain"), an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, from Evolve Power Ltd. ("Evolve"), formerly known as Montem Resources Limited. The acquisition includes the land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company paid Evolve approximately $8 million on closing of the transaction. Additional contingent payments of up to $17 million may become payable to Evolve based on the achievement of specific development and commercial milestones. The Company and Evolve own the Tent Mountain project within a special purpose partnership that is jointly managed, with the Company acting as project developer. The partnership is actively seeking an offtake agreement for the energy and environmental attributes generated by the facility.

Automatic Share Purchase Plan

On March 27, 2023, the Company entered into an automatic share purchase plan ("ASPP") in order to facilitate repurchases of TransAlta's common shares under its previously announced NCIB. Under the ASPP, the Company's broker purchased 2,943,600 common shares. The ASPP terminated on May 30, 2023. All common shares acquired pursuant to the ASPP were cancelled.

During the nine months ended Sept. 30, 2023, the Company purchased and cancelled a total of 6,112,900 common shares, including those purchased under the ASPP, at an average price of $11.62 per common share, for a total cost of $71 million.

Refer to the audited annual 2022 consolidated financial statements within our 2022 Annual Integrated Report and our unaudited interim condensed consolidated financial statements for the three and nine months ended Sept. 30, 2023, for significant events impacting both prior and current year results.

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 generation and summary financial information on a consolidated basis for each of our segments:

	LTA generation (GWh)[1]		Actual production (GWh)[2]		Adjusted EBITDA[3]	
3 months ended Sept. 30	**2023**	2022	**2023**	2022	**2023**	2022
Hydro	**573**	576	**521**	738	**150**	245
Wind and Solar	**1,246**	930	**708**	685	**37**	42
Renewables	**1,819**	1,506	**1,229**	1,423	**187**	287
Gas			**3,294**	2,842	**254**	195
Energy Transition			**1,155**	1,167	**29**	51
Energy Marketing					**13**	53
Corporate					**(30)**	(31)
Total			**5,678**	5,432	**453**	555
Earnings before income taxes					**453**	126

	LTA generation (GWh)[1]		Actual production (GWh)[2]		Adjusted EBITDA[3]	
9 months ended Sept. 30	**2023**	2022	**2023**	2022	**2023**	2022
Hydro	**1,568**	1,580	**1,443**	1,644	**403**	394
Wind and Solar	**3,766**	3,451	**2,764**	3,026	**175**	219
Renewables	**5,334**	5,031	**4,207**	4,670	**578**	613
Gas			**8,981**	8,073	**660**	365
Energy Transition			**3,058**	2,510	**96**	67
Energy Marketing					**95**	120
Corporate					**(86)**	(72)
Total			**16,246**	15,253	**1,343**	1,093
Earnings before income taxes					**915**	346

(1) *Long-term average production ("LTA Generation (GWh)") is calculated based on our portfolio as at Sept. 30, 2023, 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 (GWh) for Energy Transition is not considered as we are currently transitioning these units with the expectation that they will retire by the end of 2025 and the LTA Generation (GWh) for Gas is not considered as it is largely dependent on market conditions and merchant demand. Wind and Solar LTA Generation (GWh) for the three and nine months ended Sept. 30, 2023, excluding the Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 1,165 GWh and 3,491 GWh.*

(2) *Actual production levels are compared against the long-term average to highlight the impact of an important factor that affects the variability in our business results. In the short-term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next and over time facilities will continue to produce in line with their long-term averages, which has proven to be a reliable indicator of performance.*

(3) *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 Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Gross installed capacity (MW)[1]	**922**	925	**922**	925
LTA generation (GWh)[2]	**573**	576	**1,568**	1,580
Availability (%)	**97.8**	97.7	**95.6**	96.6
Production				
Contract production (GWh)	**87**	125	**229**	292
Merchant production (GWh)	**434**	613	**1,214**	1,352
Total energy production (GWh)	**521**	738	**1,443**	1,644
Ancillary service volumes (GWh)[3]	**659**	797	**1,872**	2,324
Alberta Hydro Assets revenues[4][5]	**92**	151	**258**	240
Other Hydro Assets and other revenues[4][6]	**17**	12	**41**	34
Alberta Hydro ancillary services revenues[3]	**54**	102	**146**	172
Environmental attribute revenues	**—**	—	**9**	1
Revenues[7]	**163**	265	**454**	447
Fuel and purchased power	**4**	7	**14**	17
Gross margin[8]	**159**	258	**440**	430
OM&A	**9**	12	**35**	33
Taxes, other than income taxes	**—**	1	**2**	3
Adjusted EBITDA[8]	**150**	245	**403**	394
Supplemental Information:				
Gross revenues per MWh				
Alberta Hydro Assets energy ($/MWh)[4][5]	**226**	246	**222**	177
Alberta Hydro Assets ancillary ($/MWh)[3]	**82**	128	**78**	74
Sustaining capital	**11**	8	**25**	20

(1) In the fourth quarter of 2022, the Company closed the sale of two Hydro assets resulting in a reduction in capacity of 3 MW.
(2) 2022 LTA generation revised for consistency with calculation methodology used in 2023.
(3) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(4) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro assets includes our hydro facilities in BC and Ontario, hydro facilities in Alberta (other than the Alberta Hydro Assets) and transmission revenues.
(5) The Company entered into forward hedges for the first and third quarter of 2023 that are included in the Alberta Hydro Asset revenues.
(6) 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.
(7) 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.
(8) 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.

The Hydro fleet continues to perform above management's expectations for the segment and was in line with our revised expected full year financial guidance provided in the second quarter of 2023. Availability for the three months ended Sept. 30, 2023, was consistent with the same period in 2022. Availability for the nine months ended Sept. 30, 2023, decreased compared to the same period in 2022, primarily due to planned outages at our Alberta Hydro Assets.

Production decreased by 217 GWh and 201 GWh, respectively, compared to the same periods in 2022 and was slightly below segment expectations for the period due to lower than average water resource. Production was expected to be lower in the three-month period ended Sept. 30, 2023 as production in 2022 was positively impacted by a delayed spring runoff. For the nine months ended Sept. 30, 2023, production was negatively impacted by icing constraints and lower availability at the Alberta Hydro Assets, compared to the same period in 2022.

Ancillary services volumes for the three and nine months ended Sept. 30, 2023, exceeded our expectations, however, decreased by 138 GWh and 452 GWh, comparatively to the same periods in 2022 due to the AESO procuring lower volumes of ancillary services given its decision to reduce the cumulative volume of imports into Alberta via the British Columbia and Montana transmission interconnections and the Company managing variable hydrology conditions across the second and third quarters. In addition, ancillary service volumes for the three months ended Sept. 30, 2022 were positively impacted by a delayed spring runoff.

Adjusted EBITDA for the three and nine months ended exceeded our expectations for both the periods. Energy prices and ancillary service prices were higher than originally anticipated. Adjusted EBITDA for the three months ended Sept. 30, 2023, decreased by $95 million compared to the same period in 2022, as 2022 was exceptional and benefited from a delayed spring runoff in the third quarter of 2022 and exceptional energy and ancillary service pricing in the Alberta market. Adjusted EBITDA for the nine months ended Sept. 30, 2023, increased by $9 million, compared to the same period in 2022, primarily due to higher realized energy and ancillary services prices in the Alberta market, and higher sales of environmental attributes, partially offset by higher OM&A costs. OM&A for the nine months ended Sept. 30, 2023, increased primarily due to higher legal fees, higher insurance costs, salary escalations and incentive accruals. For the three and nine months ended Sept. 30, 2023, the Company captured revenue by forward hedging for the Alberta Hydro Assets and realized gains from the hedging strategy. For further discussion on the Alberta market conditions and pricing, refer to the Alberta Electricity Portfolio section of this MD&A.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2023, were higher by $3 million and $5 million, respectively, compared to the same periods in 2022 due to higher planned maintenance costs.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Gross installed capacity (MW)(1)	**2,036**	1,906	**2,036**	1,906
LTA generation (GWh)	**1,246**	930	**3,766**	3,451
Availability (%)	**87.0**	85.0	**85.7**	83.1
Contract production (GWh)	**520**	537	**2,022**	2,247
Merchant production (GWh)	**188**	148	**742**	779
Total production (GWh)	**708**	685	**2,764**	3,026
Wind and Solar revenues	**63**	64	**236**	253
Environmental attribute revenues	**3**	3	**23**	33
Revenues(2)	**66**	67	**259**	286
Fuel and purchased power	**6**	6	**22**	20
Carbon compliance	**—**	—	**—**	1
Gross margin(3)	**60**	61	**237**	265
OM&A	**20**	19	**55**	50
Taxes, other than income taxes	**4**	1	**11**	7
Net other operating income(2)	**(1)**	(1)	**(4)**	(11)
Adjusted EBITDA(3)	**37**	42	**175**	219
Supplemental information:				
Sustaining capital	**3**	5	**9**	12
Kent Hills wind rehabilitation expenditures(4)	**20**	31	**62**	41
Insurance proceeds - Kent Hills	**—**	—	**(1)**	(7)

(1) Gross installed capacity and availability as at Sept. 30, 2023 include the 130 MW Garden Plain wind facility. Commercial operation of the facility was achieved in August 2023.
(2) For details of the adjustments to revenues and net other operating income 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.
(4) The Kent Hills wind facilities rehabilitation capital expenditures are segregated from the sustaining capital expenditures due to the extraordinary nature of the expenditures and have been reflected separately.

Availability for the three and nine months ended Sept. 30, 2023, increased compared to the same periods in 2022, primarily due to the partial return to service of the Kent Hills facilities and the commissioning of the Garden Plain wind facility, partially offset by the lower performance of solar assets in the third quarter. For the nine months ended Sept. 30, 2023, the higher availability was partially offset by an extended forced outage at the Windrise facility in the first quarter of 2023 caused by a manufacturing defect on a transformer bushing that has since been repaired under warranty and resolved. The Kent Hills facilities are expected to fully return to service by the end of the fourth quarter of 2023. Availability adjusted for the Kent Hills extended outage for the three and nine months ended Sept. 30, 2023, was 92.5 per cent and 92.3 per cent, respectively, and 92.2 per cent and 90.3 per cent for the same periods in 2022.

Production for the three months ended Sept. 30, 2023, increased by 23 GWh compared to the same period in 2022 primarily due to the partial return to service of the Kent Hills facilities and the addition of the Garden Plain wind facility, partially offset by lower wind resources across all regions. Production for the nine months ended Sept. 30, 2023, decreased by 262 GWh, compared to the same period in 2022, primarily due to lower wind resources across all regions, partially offset by production from the Kent Hills and Garden Plain wind facilities.

Adjusted EBITDA for the three months ended Sept. 30, 2023, decreased by $5 million compared to the same period in 2022, primarily due to lower revenues driven by weaker wind resource across the operating fleet, partially offset by the addition of the Garden Plain wind facility and the partial return to service of the Kent Hills wind facilities. Adjusted EBITDA for the nine months ended Sept. 30, 2023, decreased by $44 million, compared to the same period in 2022, primarily due to lower production, weaker wind resource, lower environmental attribute revenues driven by a reduction to offsets and emission credit sales and lower liquidated damages recognized at the Windrise wind facility. OM&A in both periods increased due to salary escalations, higher insurance costs and long-term service agreement escalations.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2023, decreased by $2 million and $3 million, respectively, compared to the same periods in 2022, mainly due to lower maintenance costs at the wind facilities.

Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Gross installed capacity (MW)	**3,084**	3,084	**3,084**	3,084
Availability (%)	**94.6**	97.8	**92.3**	95.2
Contract production (GWh)	**951**	887	**2,859**	2,657
Merchant production (GWh)	**2,373**	1,974	**6,271**	5,460
Purchased power (GWh)	**(30)**	(19)	**(149)**	(44)
Total production (GWh)	**3,294**	2,842	**8,981**	8,073
Revenues(1)	**430**	431	**1,185**	984
Fuel and purchased power(1)	**110**	166	**323**	442
Carbon compliance	**28**	26	**85**	56
Gross margin(2)	**292**	239	**777**	486
OM&A	**45**	49	**136**	138
Taxes, other than income taxes	**3**	5	**11**	13
Net other operating income	**(10)**	(10)	**(30)**	(30)
Adjusted EBITDA(2)	**254**	195	**660**	365
Supplemental information:				
Sustaining capital:	**15**	8	**32**	16

(1) *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.*
(2) *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.*

The Gas fleet significantly exceeded management's expectations for the segment and performance is consistent with our revised expected full year financial guidance provided in the second quarter of 2023. Availability for the three and nine months ended Sept. 30, 2023, decreased in line with our expectations compared to the same periods in 2022 due to planned outages. Availability for the three months ended Sept. 30, 2023, was impacted by planned outages at Sundance Unit 6 and planned and unplanned outages at the Sarnia cogeneration facility. For the nine months ended Sept. 30, 2023, availability was impacted by planned outages at Sheerness Unit 1 and Keephills Unit 3.

Production for the three and nine months ended Sept. 30, 2023, increased by 452 GWh and 908 GWh, respectively, compared to the same periods in 2022, mainly due to stronger market conditions resulting in higher dispatch for our Alberta merchant gas assets and higher contract production in Ontario, partially offset by higher purchased power required to fulfill contractual obligations during planned outages and lower contract production from Australia gas assets due to constrained natural gas supply and from our US gas facility due to lower availability. For both the three and nine months ended Sept. 30, 2023, production was not impacted by the decrease in availability.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2023, increased by $59 million and $295 million, respectively, compared to the same periods in 2022, mainly due to higher production from stronger market conditions in Alberta, lower natural gas prices and higher hedged gas volumes, partially offset by lower thermal revenues due to reduced customer demand in Ontario. The nine months ended Sept. 30, 2023, further benefited from higher realized energy prices for our Alberta gas merchant assets, net of hedging, partially offset by higher carbon costs and fuel usage related to production.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2023, increased by $7 million and $16 million, respectively, compared to the same periods in 2022, mainly due to higher planned major maintenance costs at the gas facilities.

Energy Transition

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Gross installed capacity (MW)	**671**	671	**671**	671
Availability (%)	**86.2**	96.6	**79.8**	77.4
Adjusted availability (%)[1]	**86.2**	96.6	**79.8**	79.8
Contract sales volume (GWh)	**839**	839	**2,489**	2,489
Merchant sales volume (GWh)	**1,244**	1,251	**3,243**	2,780
Purchased power (GWh)[2]	**(928)**	(923)	**(2,674)**	(2,759)
Total production (GWh)	**1,155**	1,167	**3,058**	2,510
Revenues[3]	**193**	237	**564**	450
Fuel and purchased power	**148**	167	**419**	332
Carbon compliance	**—**	2	**—**	(1)
Gross margin[4]	**45**	68	**145**	119
OM&A	**15**	17	**46**	50
Taxes, other than income taxes	**1**	—	**3**	2
Adjusted EBITDA[4]	**29**	51	**96**	67
Supplemental information:				
Highvale mine reclamation spend	**3**	2	**9**	7
Centralia mine reclamation spend	**3**	4	**10**	11
Sustaining capital	**2**	2	**13**	18

(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.

Adjusted availability for the three months ended Sept. 30, 2023, decreased compared with the same period in 2022, due to higher unplanned outages at Centralia Unit 2. Adjusted availability for the nine months ended Sept. 30, 2023, was consistent compared to the same period in 2022. There were lower planned outages at Centralia Unit 2, offset by the retirement of Sundance Unit 4 in the first quarter of 2022.

Production decreased by 12 GWh for the three months ended Sept. 30, 2023, compared to the same period in 2022, primarily due to lower merchant sales volume. Production increased by 548 GWh for the nine months ended Sept. 30, 2023, compared to the same period in 2022, primarily due to higher dispatch related to higher merchant pricing and higher availability at Centralia.

Adjusted EBITDA decreased by $22 million for the three months ended Sept. 30, 2023, compared to the same period in 2022, primarily due to lower merchant prices, partially offset by lower purchased power costs. Adjusted EBITDA increased by $29 million for the nine months ended Sept. 30, 2023, compared to the same period in 2022, primarily due to higher merchant pricing and higher production, partially offset by higher purchased power costs required to fulfill contractual obligations during planned and unplanned outages. Lower OM&A expenses also favourably impacted the period due to the retirement of Sundance Unit 4 in the first quarter of 2022.

Mine reclamation spending for the Highvale and Centralia mines was consistent with 2022.

Sustaining capital expenditures for the three months ended Sept. 30, 2023, were consistent compared to the same period in 2022. Sustaining capital expenditures for the nine months ended Sept. 30, 2023, decreased by $5 million compared to the same period in 2022, due to a reduction in planned major maintenance.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Revenues(1)	**26**	62	**128**	143
OM&A	**13**	9	**33**	23
Adjusted EBITDA(2)	**13**	53	**95**	120

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

Adjusted EBITDA for the three and nine months ended Sept. 30, 2023, decreased by $40 million and $25 million, respectively, compared to the same periods in 2022. Gross margin for the three and nine months ended Sept. 30, 2023, was above segment expectations but adjusted EBITDA was lower period over period due to adjustments to revenues to account for the timing of realized gains and losses on closed exchange positions and unrealized mark-to-market gains and losses which are expected to be realized in future quarters. OM&A increased mainly due to higher incentives related to revenues before adjustments. The Company was able to capitalize on volatility in the trading of both physical and financial power and gas products across North American deregulated markets while maintaining the overall risk profile of the business unit.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
OM&A	**30**	30	**86**	71
Taxes, other than income taxes	**—**	1	**—**	1
Adjusted EBITDA(1)	**(30)**	(31)	**(86)**	(72)
Supplemental information:				
Sustaining capital:	**5**	4	**21**	9

(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 Sept. 30, 2023, was consistent compared to the same period in 2022. Adjusted EBITDA for the nine months ended Sept. 30, 2023, decreased by $14 million, compared to the same period in 2022, primarily due to higher incentive accruals reflecting the Company's performance, increased spending to support strategic and growth initiatives and increased costs due to inflationary pressures.

Sustaining capital expenditures for the three months ended Sept. 30, 2023, were consistent compared to the same period in 2022. For the nine months ended Sept. 30, 2023, sustaining capital expenditures increased by $12 million, compared to the same period in 2022, mainly due to higher spend on leasehold improvements and information technology associated with the relocation of the Company's head office.

Performance by Segment with Supplemental Geographical Information

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

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

3 months ended Sept. 30, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing(3)	Corporate	Total
Alberta	239	14	139	(6)	53	(31)	408
Canada, excluding Alberta	6	14	21	—	—	—	41
US	—	14	2	57	—	—	73
Australia	—	—	33	—	—	—	33
Adjusted EBITDA(1)	245	42	195	51	53	(31)	555
Earnings before income taxes							126

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

9 months ended Sept. 30, 2022	Hydro	Wind and Solar	Gas	Energy Transition(2)	Energy Marketing(3)	Corporate	Total
Alberta	382	85	194	(12)	120	(72)	697
Canada, excluding Alberta	12	70	64	—	—	—	146
US	—	64	6	79	—	—	149
Australia	—	—	101	—	—	—	101
Adjusted EBITDA(1)	394	219	365	67	120	(72)	1,093
Earnings before income taxes							346

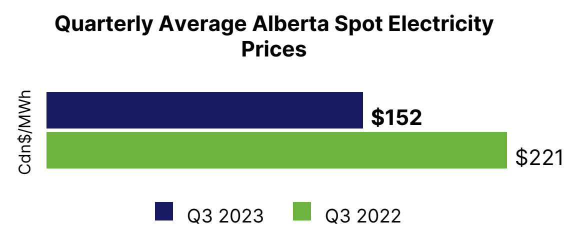
(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Presenting this from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance 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.
(2) The Sundance Unit 4 was retired March 31, 2022.
(3) The adjusted EBITDA for the Energy Marketing segment was reclassified to the Alberta region to reflect where the operations reside.

Alberta Electricity Portfolio

Generating capacity in Alberta is subject to market forces, rather than rate regulation. 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.

Approximately 53 per cent of our gross installed capacity is located in Alberta. Our portfolio of merchant assets in Alberta consists of hydro facilities, wind facilities, a battery storage facility, a cogeneration facility that is partially contracted and merchant and converted natural-gas-fired thermal facilities. Some of the wind and gas facilities within the Alberta electricity portfolio operate on long-term contracts. Optimization of portfolio performance is driven by the diversity of fuel types, which enables portfolio management and allows for the maximization of operating margins. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. A portion of the installed generation capacity in the portfolio has been hedged to provide cash flow certainty.

Alberta power prices for the third quarter of 2023 were lower compared to the same period in 2022 as a result of lower natural gas prices and higher renewable generation. Demand for the quarter was flat compared to the same period in 2022. The average pool price for the third quarter of 2023 decreased as a result of these factors from $221 per MWh in 2022 to $152 per MWh in 2023.



	2023					2022				
3 months ended Sept. 30	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind & Solar	Gas	Energy Transition	Total
Total production (GWh)	**434**	**323**	**2,335**	**—**	**3,092**	614	259	1,993	—	2,866
Contract production (GWh)	**—**	**135**	**137**	**—**	**272**	4	111	127	—	242
Merchant production (GWh)	**434**	**188**	**2,198**	**—**	**2,820**	610	148	1,866	—	2,624
Revenues(1)	**157**	**22**	**325**	**2**	**506**	256	25	290	(2)	569
Fuel and purchased power	**3**	**4**	**87**	**—**	**94**	6	3	110	—	119
Carbon compliance	**—**	**—**	**30**	**—**	**30**	—	1	23	2	26
Gross margin	**154**	**18**	**208**	**2**	**382**	250	21	157	(4)	424

	2023					2022				
9 months ended Sept. 30	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind & Solar	Gas	Energy Transition	Total
Total production (GWh)	**1,214**	**1,163**	**6,394**	**—**	**8,771**	1,356	1,211	5,537	19	8,123
Contract production (GWh)	**—**	**421**	**423**	**—**	**844**	4	433	385	—	822
Merchant production (GWh)	**1,214**	**742**	**5,971**	**—**	**7,927**	1,352	778	5,152	19	7,301
Revenues(1)	**438**	**92**	**862**	**4**	**1,396**	426	109	588	5	1,128
Fuel and purchased power	**12**	**15**	**255**	**—**	**282**	14	12	294	5	325
Carbon compliance	**—**	**—**	**81**	**—**	**81**	—	1	47	(1)	47
Gross margin	**426**	**77**	**526**	**4**	**1,033**	412	96	247	1	756

(1) Revenue has been adjusted to exclude the impact of unrealized mark-to-market gains or losses and realized gains and losses on closed exchange positions in order to depict revenue realized in the periods.

For the three and nine months ended Sept. 30, 2023, the Alberta electricity portfolio generated 3,092 GWh and 8,771 GWh of energy, respectively. This was an increase of 226 GWh and 648 GWh, respectively, compared to the same periods in 2022. Higher production in the three and nine months ended Sept. 30, 2023, was primarily due to higher dispatch and higher hedged gas volumes from our merchant gas assets, partially offset by lower water and wind resources in Alberta.

Gross margin for the three and nine months ended Sept. 30, 2023, was $382 million and $1,033 million, respectively, a decrease of $42 million and increase of $277 million, respectively, compared to the same periods in 2022. Lower gross margin in the three months ended Sept. 30, 2023, was a result of lower energy production, lower ancillary service prices, lower ancillary services volumes and lower realized energy prices from the Hydro assets, partially offset by higher dispatch from the Gas assets. Higher gross margin for the nine months ended Sept. 30, 2023, was primarily due to merchant revenues and higher realized energy prices for our Gas assets. In 2023, more gas fuel costs were hedged and the natural gas prices were lower compared to 2022.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Spot power price average per MWh	**$152**	$221	**$151**	$145
Natural gas price (AECO) per GJ	**$2.49**	$4.04	**$2.65**	$5.14
Carbon compliance price per tonne	**$65**	$50	**$65**	$50
Realized merchant power price per MWh(1)	**$179**	$253	**$176**	$164
Hydro energy spot power price per MWh	**$195**	$246	**$192**	$177
Hydro ancillary spot price per MWh	**$82**	$128	**$78**	$74
Wind energy spot power price per MWh	**$103**	$136	**$89**	$86
Gas and Energy Transition spot power price per MWh	**$173**	$264	**$174**	$171
Hedged volume (GWh)(2)	**2,086**	1,681	**5,800**	5,320
Hedged power price average per MWh	**$120**	$80	**$117**	$79
Fuel and purchased power per MWh(3)	**$40**	$60	**$44**	$58
Carbon compliance cost per MWh(3)	**$13**	$13	**$13**	$8

(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 (excluding assets under long-term contract and ancillary revenues) and portfolio optimization activities divided by total merchant GWh produced.
(2) Hedge volumes are for production volumes primarily from the Gas segment.
(3) 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, and carbon compliance cost per MWh may include emission credits to settle a portion of our GHG carbon pricing obligations.

For the three and nine months ended Sept. 30, 2023, the realized merchant power price per MWh of production decreased by $74 per MWh and increased by $12 per MWh, respectively, compared to the same periods in 2022. For the three months ended Sept. 30, 2023, realized merchant power price per MWh was strong but lower than the comparative period, primarily due to lower natural gas prices. For the nine months ended Sept. 30, 2023, higher realized merchant power pricing for energy across the portfolio was primarily due to higher market prices and optimization of our available capacity across all fuel types. The segment spot prices exclude gains and losses from hedging positions that are entered into in order to mitigate the impact of unfavourable market pricing.

For the three and nine months ended Sept. 30, 2023, the fuel and purchased power cost per MWh of production decreased by $20 per MWh and $14 per MWh, respectively, compared with the same periods in 2022 primarily due to lower natural gas prices.

For the three months ended Sept. 30, 2023, carbon compliance costs per MWh were consistent with the same period in 2022. For the nine months ended Sept. 30, 2023, carbon compliance costs per MWh of production increased by $5 per MWh, compared with the same period in 2022. In 2022, the Company utilized emission credits to settle a portion of the 2021 carbon compliance obligation resulting in a lower carbon cost per MWh. Carbon compliance prices increased from $50 per tonne in 2022 to $65 per tonne in 2023.

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.

	Q4 2022	Q1 2023	Q2 2023	Q3 2023
Revenues	854	1,089	625	**1,017**
Earnings before income taxes	7	383	79	**453**
Cash flow from operating activities	351	462	11	**681**
Net earnings (loss) attributable to common shareholders	(163)	294	62	**372**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(2)	(0.61)	1.10	0.23	**1.41**
	Q4 2021	**Q1 2022**	**Q2 2022**	**Q3 2022**
Revenues	610	735	458	929
Earnings (loss) before income taxes	(32)	242	(22)	126
Cash flow from (used in) operating activities(1)	54	451	(129)	204
Net earnings (loss) attributable to common shareholders	(78)	186	(80)	61
Net earnings (loss) per share attributable to common shareholders, basic and diluted(2)	(0.29)	0.69	(0.30)	0.23

(1) 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.

(2) 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.

Net earnings (loss) attributable to common shareholders over the prior eight quarters has also been impacted by the following variations and events:

- Higher revenues arising from higher overall availability during periods of peak pricing and higher power prices in Alberta in the second, third and fourth quarters of 2022 and the first and second quarters of 2023. In 2023, higher gas volumes were hedged yielding higher revenues compared to 2022;
- Lower natural gas pricing in 2023 and higher natural gas pricing in 2022. In 2023, a higher portion of gas fuel costs were hedged at lower pricing;
- Increased natural gas consumption in the first, third and fourth quarters of 2022 and in the first and third quarters of 2023 for the units that were converted to gas in 2021;
- Lower carbon costs in 2022 related to our transition off coal and the utilization of emission credits to settle a portion of our GHG obligation in the second quarter of 2022. Higher carbon costs in the first, second and third quarters of 2023 due to higher carbon costs per tonne and, in the first and third quarters of 2023, higher production and the settlement of the 2022 carbon compliance obligation with cash in the second quarter of 2023;
- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the fourth quarter of 2021 through to the third quarter of 2023. The facilities were partially returned to service in the third quarter of 2023. The extended outage will continue into the fourth quarter of 2023;
- The effects of asset impairment reversals recognized in the first, second and third quarters of 2023 and the effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning provisions for retired assets from changes in estimated cash flows and discount rates in all periods shown;
- Accelerated timing of decommissioning cash flows and changes in useful lives recognized in the third quarter of 2022. Decelerated timing of decommissioning cash flows and changes in useful lives recognized in the third quarter of 2023;
- Insurance proceeds for the single tower failure at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022 and $1 million in the third quarter of 2023;
- Liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility recorded in each quarter in 2022 and the first, second and third quarters of 2023;
- Keephills Unit 1 and Sundance Unit 5 being retired in the fourth quarter of 2021, and Sundance Unit 4 being retired in the first quarter of 2022;
- The acquisition of North Carolina Solar facility in the fourth quarter of 2021;
- Commissioning of the Windrise wind facility in the fourth quarter of 2021 and the Garden Plain wind facility in the third quarter of 2023;
- Gains relating to the sale of assets being recognized in the fourth quarter of 2022;
- Fluctuations in the Canadian dollar relative to the US dollar resulting in foreign exchange gains and losses on our US-denominated long-term debt balances not designated as hedges; and
- Fluctuations in current and future tax expense with earnings before tax across the quarters. Future tax expense decreased from 2022 mainly due to an adjustment in the US to mitigate cash tax relating to the Base Erosion and Anti-Avoidance Tax ("BEAT").

Financial Position

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2022, to Sept. 30, 2023:

	Sept. 30, 2023	Dec. 31, 2022	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**1,231**	1,134	97
Trade and other receivables	**834**	1,589	(755)
Risk management assets	**143**	709	(566)
Other current assets(1)	**302**	282	20
Total current assets	**2,510**	3,714	(1,204)
Non-current assets			
Risk management assets	**84**	161	(77)
Property, plant and equipment, net	**5,677**	5,556	121
Other non-current assets(2)	**1,249**	1,310	(61)
Total non-current assets	**7,010**	7,027	(17)
Total assets	**9,520**	10,741	(1,221)
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**687**	1,346	(659)
Risk management liabilities	**335**	1,129	(794)
Income taxes payable	**16**	73	(57)
Dividends payable	**15**	68	(53)
Credit facilities, long-term debt and lease liabilities	**529**	178	351
Other current liabilities(3)	**45**	94	(49)
Total current liabilities	**1,627**	2,888	(1,261)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,030**	3,475	(445)
Decommissioning and other provisions (long-term)	**614**	659	(45)
Risk management liabilities (long-term)	**222**	333	(111)
Defined benefit obligation and other long-term liabilities	**243**	294	(51)
Other non-current liabilities(4)	**1,121**	1,103	18
Total non-current liabilities	**5,230**	5,864	(634)
Total liabilities	**6,857**	8,752	(1,895)
Equity			
Equity attributable to shareholders	**1,892**	1,110	782
Non-controlling interests	**771**	879	(108)
Total equity	**2,663**	1,989	674
Total liabilities and equity	**9,520**	10,741	(1,221)

(1) Includes restricted cash, prepaid expenses, inventory and assets held for sale.
(2) Includes investments, long-term portion of finance lease receivables, 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 and current portion of contract liabilities.
(4) Includes exchangeable securities, deferred income tax liabilities and contract liabilities.

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

Working Capital

The excess of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $883 million as at Sept. 30, 2023 (Dec. 31, 2022 – $826 million).

Current assets decreased by $1,204 million to $2,510 million as at Sept. 30, 2023, from $3,714 million as at Dec. 31, 2022, primarily due to lower trade receivables related to collections from higher revenues recognized in the fourth quarter of 2022, lower receivables in the Energy Marketing segment and higher return of collateral previously posted. Risk management assets decreased mainly due to lower market prices and contract settlements since year end. These decreases were partially offset by higher cash and cash equivalents.

Current liabilities decreased by $1,261 million from $2,888 million as at Dec. 31, 2022, to $1,627 million as at Sept. 30, 2023, mainly due to the payment of year-end accounts payable and accrued liabilities including the settlement of the 2022 GHG obligation, return of collateral received, lower accruals and payables in the Energy Marketing segment, and lower income taxes payable. Additionally, risk management liabilities decreased due to lower market prices as well as contract settlements since year end. As at Sept. 30, 2023, the Company held nil (Dec. 31, 2022 – $260 million) of cash collateral received related to derivative instruments. The decrease was partially offset by the classification of the $400 million TransAlta Corporation Term Facility from long-term to current debt as a result of its scheduled maturity in the third quarter of 2024.

Non-Current Assets

Non-current assets as at Sept. 30, 2023, were $7,010 million, a decrease of $17 million from $7,027 million as at Dec. 31, 2022, primarily due to lower risk management assets due to changes in market pricing across multiple markets and contract settlements. This was partially offset by the increase in additions to property, plant and equipment ("PP&E") of $641 million, mainly related to the construction of the Garden Plain wind project, the White Rock wind projects, the Horizon Hill wind project, the Northern Goldfields solar project, the Mount Keith 132kv transmission expansion, the Kent Hills rehabilitation costs and other planned major maintenance, partially offset by depreciation of $460 million.

Non-Current Liabilities

Non-current liabilities as at Sept. 30, 2023, were $5,230 million, a decrease of $634 million from $5,864 million as at Dec. 31, 2022, mainly due to lower risk management liabilities of $111 million due to contract settlements and pricing, and a $445 million decrease in long-term debt and lease liabilities related to scheduled debt repayments, reclassification of the term facility to current liabilities and a $47 million favourable foreign exchange impact.

Total Equity

As at Sept. 30, 2023, the increase in total equity of $674 million was due to net earnings of $850 million and gains on derivatives from cash flow hedges of $120 million, partially offset by distributions to non-controlling interests of $179 million, share repurchases under the NCIB of $71 million and dividends declared on common and preferred shares of $56 million.

Financial Capital

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

Capital Structure

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

	Sept. 30, 2023		Dec. 31, 2022	
	$	%	$	%
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**4**	251	5
Recourse debt - US senior notes	**931**	**16**	934	18
Term Facilities	**476**	**8**	428	9
Other	**—**	**—**	1	—
Less: cash and cash equivalents(1)	**(1,231)**	**(21)**	(1,118)	(21)
Less: other cash and liquid assets(2)	**(20)**	**—**	(20)	—
Net senior unsecured debt	**407**	**7**	476	11
Other debt liabilities				
Exchangeable debentures	**343**	**6**	339	6
Non-recourse debt				
TAPC Holdings LP bond	**87**	**2**	94	2
OCP Bond	**217**	**4**	241	4
Pingston bond	**39**	**1**	45	1
Melancthon Wolfe Wind bond	**185**	**3**	202	4
New Richmond Wind bond	**107**	**2**	112	2
Kent Hills Wind bond	**197**	**3**	206	4
Windrise Wind bond	**166**	**3**	170	3
South Hedland non-recourse debt	**658**	**12**	711	14
US tax equity financing	**113**	**2**	123	2
Lease liabilities	**132**	**2**	135	2
Total consolidated net debt(3)(4)(5)	**2,651**	**47**	2,854	55
Non-controlling interests	**771**	**13**	879	17
Exchangeable preferred securities(5)	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**2,808**	**49**	2,863	54
Preferred shares	**942**	**16**	942	18
Contributed surplus, deficit and accumulated other comprehensive income	**(1,858)**	**(32)**	(2,695)	(51)
Total capital	**5,714**	**100**	5,243	100

(1) Cash and cash equivalents is net of bank overdraft.
(2) Includes principal portion of the TransAlta OCP restricted cash related to the TransAlta OCP non-recourse 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 2023 and 2025, we have $703 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 $0 million of exchangeable securities can be exchanged at the earliest on Jan. 1, 2025.

Pingston Bond Refinancing

On Sept. 14, 2023, the Company closed a non-recourse bond financing for approximately $39 million ("Pingston bond") as a replacement for the non-recourse bond that matured on May 8, 2023. The Pingston bond is secured by a first ranking charge over all the respective assets of the Company's subsidiaries that issued the bonds, amortizes and bears interest at a rate of 6.145 per cent per annum, payable semi-annually, and matures on May 8, 2043. The Pingston bond is subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facility's operations.

Credit Facilities

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

As at Sept. 30, 2023		Utilized			
Credit facilities	Facility size	Outstanding letters of credit[(1)]	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta Corporation syndicated credit facility	1,250	355	—	895	Q2 2027
TransAlta Renewables syndicated credit facility	700	3	81	616	Q2 2027
TransAlta Corporation bilateral credit facilities	240	171	—	69	Q2 2025
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**529**	**481**	**1,580**	
Non-Committed					
TransAlta Corporation demand facilities	250	88	—	162	N/A
TransAlta Renewables demand facility	150	102	—	48	N/A
Total Non-Committed	**400**	**190**	**—**	**210**	

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

In June 2023, the TransAlta syndicated credit facility and TransAlta Renewables syndicated credit facility were amended and maturity dates were extended from June 30, 2026 to June 30, 2027. The TransAlta bilateral credit facilities were also amended and maturity dates were extended from June 30, 2024 to June 30, 2025.

On Oct. 5, 2023, upon closing the TransAlta Renewables transaction, the syndicated credit facilities were amended to effectively consolidate the TransAlta Renewables syndicated credit facility and non-committed demand facility into the TransAlta credit facilities. The cash drawings on the TransAlta Renewables' syndicated credit facility were repaid and the outstanding letters of credit were transferred to the TransAlta non-committed demand facility. The TransAlta Renewables' credit facilities were then terminated. This resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion. See the Significant and Subsequent events section of this MD&A for more details.

Non-Recourse Debt

The Melancthon Wolfe Wind LP, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd, Windrise Wind LP and TransAlta OCP LP non-recourse bonds, are subject to customary financing conditions and covenants that may restrict the Company’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter of 2023, with the exception of Kent Hills Wind LP and TAPC Holdings LP. Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed and TAPC Holdings LP has been impacted by higher interest rates in 2023. The funds in these entities that have accumulated since the third quarter test will not be capable of being distributed until the next debt service coverage ratio is calculated in the fourth quarter of 2023. At Sept. 30, 2023, $74 million (Dec. 31, 2022 – $50 million) of cash was not capable of being distributed due to these financial restrictions. 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

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Interest on debt	**51**	42	**152**	123
Interest on exchangeable debentures	**7**	7	**22**	22
Interest on exchangeable preferred shares	**7**	7	**21**	21
Interest income	**(16)**	(7)	**(47)**	(14)
Capitalized interest	**(15)**	(4)	**(41)**	(8)
Interest on lease liabilities	**3**	1	**7**	4
Credit facility fees, bank charges and other interest	**6**	5	**17**	16
Tax shield on tax equity financing	**—**	(1)	**—**	(4)
Accretion of provisions	**10**	16	**37**	35
Net interest expense	**53**	66	**168**	195

Net interest expense for the three and nine months ended Sept. 30, 2023, was lower than the same periods in 2022, primarily due to higher capitalized interest resulting from higher capital expenditures on growth projects, and interest income due to higher cash balances and favourable interest rates. This was partially offset by higher interest on debt due to higher credit facility borrowings and unfavourable interest rates on variable rate debt.

Share Capital

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

	Number of shares *(millions)*		
As at	**Nov. 6, 2023**	**Sept. 30, 2023**	Dec. 31, 2022
Common shares issued and outstanding, end of period	**309.9**	**263.4**	268.1
Preferred shares			
Series A	9.6	9.6	9.6
Series B	2.4	2.4	2.4
Series C	10.0	10.0	10.0
Series D	1.0	1.0	1.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding in equity	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(1)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding	**39.0**	**39.0**	39.0

(1) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests

As at Sept. 30, 2023, the Company owned 60.1 per cent (Sept. 30, 2022 – 60.1 per cent) of TransAlta Renewables.

We also own 50.01 per cent TransAlta Cogeneration, LP ("TA Cogen") (Sept. 30, 2022 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and one natural-gas-fired facility (Sheerness).

Since we owned a controlling interest in TA Cogen and TransAlta Renewables as at Sept. 30, 2023, we consolidated the entire earnings, assets and liabilities in relation to those subsidiaries.

The reported net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2023, increased by $9 million and $41 million, respectively, compared to the same periods in 2022. TA Cogen net earnings attributable to non-controlling interests have increased by $3 million and $31 million, respectively, compared to the same periods in 2022, primarily due to higher merchant pricing in the Alberta market.

TransAlta Renewables net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2023, increased by $6 million and $10 million, respectively, compared to the same periods in 2022. The increase for the nine months ended Sept. 30, 2023 was primarily due to asset impairment reversals and lower depreciation, partially offset by lower revenues in the wind segment, lower liquidated damages at the Windrise wind facility, lower insurance recoveries and higher OM&A expenses. Finance income related to subsidiaries of TransAlta was higher due to higher dividends from Australia in the first quarter of the year compared to the prior year. Refer to Note 8 of the unaudited interim condensed consolidated financial statements for further details.

On Oct. 4, 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. See the Significant and Subsequent Events section of this MD&A for details.

Other Consolidated Analysis

Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in the 2022 annual audited financial statements, during 2023 the Company has incurred the following additional contractual commitments, either directly or through its interests in joint operations for the nine months ended, Sept. 30, 2023. Approximate future payments under these agreements are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Transmission	—	2	2	3	4	57	68
Total	**—**	**2**	**2**	**3**	**4**	**57**	**68**

Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed. The table above includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2022 audited annual consolidated financial statements.

Contingencies

For the current material outstanding contingencies, please refer to Note 37 of the 2022 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the *Carbon Competitiveness Incentive Regulation* and *Technology Innovation and Emissions Reduction Regulation* from 2018-2020 inclusive. The EPCs under dispute had no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement and this matter is now resolved.

Brazeau Facility - Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator ("AER") issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometers of the Brazeau Facility but permits hydraulic fracturing in all formations (except the Duvernay) within three-to-five kilometers of the Brazeau Facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licenses (which include hydraulic fracturing activities) within three-to-five kilometers of the Brazeau Facility. The regulatory hearing to consider these applications - Proceeding 379 - is scheduled to be heard from March 18 to March 29, 2024.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometers of the Brazeau Facility pose an unacceptable risk and that the applications should be denied.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within 5 km of the Brazeau Facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (ii) the Alberta Government is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau Facility. On Sept. 29, 2022, the Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the AER, and (ii) is out of time under the *Limitations Act* (Alberta). The trial has been scheduled for two weeks starting Feb. 26, 2024.

Garden Plain

Garden Plain I LP, a wholly owned subsidiary of the Company, retained a third party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction, and significant cost overruns, resulting in overdue deadlines and has asserted a claim for $49 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure.

Cash Flows

The following highlights significant changes in the Consolidated Statements of Cash Flows for the nine months ended Sept. 30, 2023 and Sept. 30, 2022:

	9 months ended Sept. 30		
	2023	2022	**Increase/ (decrease)**
Cash and cash equivalents, beginning of period	**1,134**	947	187
Provided by (used in):			
Operating activities	**1,154**	526	628
Investing activities	**(591)**	(341)	(250)
Financing activities	**(455)**	(315)	(140)
Translation of foreign currency cash	**(11)**	(1)	(10)
Cash and cash equivalents, end of period	**1,231**	816	415

Cash from operating activities for the nine months ended Sept. 30, 2023, increased compared with the same period in 2022, primarily due to higher revenues net of unrealized gains and losses from risk management activities, lower fuel and purchased power, lower net interest expense and favourable changes in working capital. This was partially offset by higher OM&A and higher carbon compliance costs.

Cash used in investing activities for the nine months ended Sept. 30, 2023, increased compared with the same period in 2022, largely due to higher cash spent on growth projects and Kent Hills rehabilitation construction activities in PP&E ($160 million) and an unfavourable change in non-cash working capital ($98 million).

Cash used in financing activities for the nine months ended Sept. 30, 2023, increased compared with the same period in 2022, largely due to:

- Increased distributions paid to subsidiaries' non-controlling interests ($78 million);
- Higher common share repurchases under the NCIB ($45 million);
- Higher repayments of long-term debt ($51 million); and
- Realized losses on financial instruments ($32 million),

partially offset by the issuance of long-term debt ($39 million) and higher net borrowings under the Company's credit facilities ($32 million).

Financial Instruments

Refer to Note 14 of the notes to the audited annual 2022 consolidated financial statements, and Note 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2023, for details on Financial Instruments.

We may enter into commodity transactions involving non-standard features for which observable market data is not available. These are defined under IFRS as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is therefore, developed using valuation models based upon internally developed assumptions or inputs. Our Level III fair values are determined using data such as unit availability, transmission congestion, or demand profiles. Fair values are validated every quarter by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the financial statements.

At Sept. 30, 2023, Level III instruments had a net liabilities carrying value of $330 million (Dec. 31, 2022 – net liabilities of $782 million). Our risk management profile has decreased in 2023 as most energy markets have moderated considerably from the extreme price and high volatility environment experienced for much of 2022. Our risk management practices have not changed materially from Dec. 31, 2022.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of earnings (loss) for the three and nine months ended Sept. 30, 2023 and 2022. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our audited annual 2022 consolidated financial statements and the unaudited interim condensed consolidated statements of earnings (loss) for the three and nine months ended Sept. 30, 2023, 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 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 net other operating income

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

Adjustments to earnings (loss) in addition to interest, taxes, depreciation and amortization

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

Funds From Operations ("FFO")

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FFO is a non-IFRS measure.

Adjustments to cash flow from operations

- FFO related to the Skookumchuck wind facility, which is treated as an equity-accounted investment under IFRS and equity income, net of distributions from joint ventures, is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for items included in cash from operations related to the decision in 2020 to accelerate being off-coal and the shutdown of the Highvale mine in 2021 ("Clean energy transition provisions and adjustments").
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity accounted joint venture.

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 Sept. 30, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	163	62	522	188	86	—	1,021	(4)	—	1,017
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	4	(112)	5	(67)	—	(170)	—	170	—
Realized gain on closed exchange positions	—	—	4	—	8	—	12	—	(12)	—
Decrease in finance lease receivable	—	—	14	—	—	—	14	—	(14)	—
Finance lease income	—	—	2	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	163	66	430	193	26	—	878	(4)	143	1,017
Fuel and purchased power	4	6	111	148	—	—	269	—	—	269
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	6	110	148	—	—	268	—	1	269
Carbon compliance	—	—	28	—	—	—	28	—	—	28
Gross margin	159	60	292	45	26	—	582	(4)	142	720
OM&A	9	20	45	15	13	30	132	(1)	—	131
Taxes, other than income taxes	—	4	3	1	—	—	8	—	—	8
Net other operating income	—	(1)	(10)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA[2]	150	37	254	29	13	(30)	453			
Finance lease income										2
Depreciation and amortization										(140)
Asset impairment reversals										58
Net interest expense										(53)
Foreign exchange loss										(5)
Loss on sale of assets and other										(1)
Earnings before income taxes										453

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

The following table reflects adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the three months ended Sept. 30, 2022:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	265	14	372	231	54	(4)	932	(3)	—	929
Reclassifications and adjustments:										
Unrealized mark-to-market loss	—	53	47	6	46	—	152	—	(152)	—
Realized loss on closed exchange positions	—	—	(4)	—	(38)	—	(42)	—	42	—
Decrease in finance lease receivable	—	—	12	—	—	—	12	—	(12)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	265	67	431	237	62	(4)	1,058	(3)	(126)	929
Fuel and purchased power	7	6	167	167	—	1	348	—	—	348
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	7	6	166	167	—	1	347	—	1	348
Carbon compliance	—	—	26	2	—	(5)	23	—	—	23
Gross margin	258	61	239	68	62	—	688	(3)	(127)	558
OM&A	12	19	49	17	9	30	136	(1)	—	135
Taxes, other than income taxes	1	1	5	—	—	1	8	—	—	8
Net other operating income	—	(1)	(10)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA[2]	245	42	195	51	53	(31)	555			
Equity income										1
Finance lease income										4
Depreciation and amortization										(179)
Asset impairment charges										(70)
Net interest expense										(66)
Foreign exchange gain										6
Gain on sale of assets and other										4
Earnings before income taxes										126

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

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

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	**456**	**263**	**1,268**	**576**	**181**	**1**	**2,745**	**(14)**	**—**	**2,731**
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	**(2)**	**(4)**	**(120)**	**(12)**	**42**	**—**	**(96)**	**—**	**96**	**—**
Realized loss on closed exchange positions	**—**	**—**	**(13)**	**—**	**(95)**	**—**	**(108)**	**—**	**108**	**—**
Decrease in finance lease receivable	**—**	**—**	**40**	**—**	**—**	**—**	**40**	**—**	**(40)**	**—**
Finance lease income	**—**	**—**	**10**	**—**	**—**	**—**	**10**	**—**	**(10)**	**—**
Adjusted revenues	**454**	**259**	**1,185**	**564**	**128**	**1**	**2,591**	**(14)**	**154**	**2,731**
Fuel and purchased power	**14**	**22**	**326**	**419**	**—**	**1**	**782**	**—**	**—**	**782**
Reclassifications and adjustments:										
Australian interest income	**—**	**—**	**(3)**	**—**	**—**	**—**	**(3)**	**—**	**3**	**—**
Adjusted fuel and purchased power	**14**	**22**	**323**	**419**	**—**	**1**	**779**	**—**	**3**	**782**
Carbon compliance	**—**	**—**	**85**	**—**	**—**	**—**	**85**	**—**	**—**	**85**
Gross margin	**440**	**237**	**777**	**145**	**128**	**—**	**1,727**	**(14)**	**151**	**1,864**
OM&A	**35**	**55**	**136**	**46**	**33**	**86**	**391**	**(2)**	**—**	**389**
Taxes, other than income taxes	**2**	**11**	**11**	**3**	**—**	**—**	**27**	**(1)**	**—**	**26**
Net other operating income	**—**	**(4)**	**(30)**	**—**	**—**	**—**	**(34)**	**—**	**—**	**(34)**
Adjusted EBITDA[2]	**403**	**175**	**660**	**96**	**95**	**(86)**	**1,343**			
Equity income										**1**
Finance lease income										**10**
Depreciation and amortization										**(489)**
Asset impairment reversals										**74**
Net interest expense										**(168)**
Gain on sale of assets and other										**4**
Earnings before income taxes										**915**

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

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the nine months ended Sept. 30, 2022:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	447	205	933	433	116	(2)	2,132	(10)	—	2,122
Reclassifications and adjustments:										
Unrealized mark-to-market loss	—	81	13	17	—	—	111	—	(111)	—
Realized gain (loss) on closed exchange positions	—	—	(11)	—	27	—	16	—	(16)	—
Decrease in finance lease receivable	—	—	34	—	—	—	34	—	(34)	—
Finance lease income	—	—	15	—	—	—	15	—	(15)	—
Adjusted revenues	447	286	984	450	143	(2)	2,308	(10)	(176)	2,122
Fuel and purchased power	17	20	445	332	—	3	817	—	—	817
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	17	20	442	332	—	3	814	—	3	817
Carbon compliance	—	1	56	(1)	—	(5)	51	—	—	51
Gross margin	430	265	486	119	143	—	1,443	(10)	(179)	1,254
OM&A	33	50	138	50	23	71	365	(1)	—	364
Taxes, other than income taxes	3	7	13	2	—	1	26	(1)	—	25
Net other operating income	—	(18)	(30)	—	—	—	(48)	—	—	(48)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(11)	(30)	—	—	—	(41)	—	(7)	(48)
Adjusted EBITDA[2]	394	219	365	67	120	(72)	1,093			
Equity income										5
Finance lease income										15
Depreciation and amortization										(411)
Asset impairment charges										(4)
Net interest expense										(195)
Foreign exchange gain										17
Gain on sale of assets and other										6
Earnings before income taxes										346

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

Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Cash flow from (used in) operating activities[1]	**681**	204	**1,154**	526
Change in non-cash operating working capital balances	**(355)**	276	**11**	252
Cash flow from operations before changes in working capital	**326**	480	**1,165**	778
Adjustments				
Share of adjusted FFO from joint venture[1]	**2**	2	**10**	7
Decrease in finance lease receivable	**14**	12	**40**	34
Clean energy transition provisions and adjustments[2]	**—**	27	**7**	35
Realized gain (loss) on closed exchanged positions	**12**	(42)	**(108)**	16
Other[3]	**3**	9	**8**	17
FFO[4]	**357**	488	**1,122**	887
Deduct:				
Sustaining capital[1]	**(36)**	(27)	**(100)**	(75)
Productivity capital	**(1)**	(1)	**(2)**	(3)
Dividends paid on preferred shares	**(14)**	(11)	**(39)**	(31)
Distributions paid to subsidiaries' non-controlling interests	**(75)**	(54)	**(204)**	(126)
Principal payments on lease liabilities	**(3)**	(2)	**(8)**	(6)
FCF[4]	**228**	393	**769**	646
Weighted average number of common shares outstanding in the period	**263**	271	**265**	271
FFO per share[4]	**1.36**	1.80	**4.23**	3.27
FCF per share[4]	**0.87**	1.45	**2.90**	2.38

(1) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(2) Includes amounts related to onerous contracts recognized in 2021.
(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.
(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Adjusted EBITDA(1)(3)	**453**	555	**1,343**	1,093
Provisions	**(4)**	(5)	**—**	5
Interest expense	**(40)**	(47)	**(123)**	(151)
Current income tax expense	**(37)**	(11)	**(55)**	(36)
Realized foreign exchange gain (loss)	**(7)**	3	**(13)**	18
Decommissioning and restoration costs settled	**(6)**	(9)	**(22)**	(23)
Other non-cash items	**(2)**	2	**(8)**	(19)
FFO(2)(3)	**357**	488	**1,122**	887
Deduct:				
Sustaining capital(3)	**(36)**	(27)	**(100)**	(75)
Productivity capital	**(1)**	(1)	**(2)**	(3)
Dividends paid on preferred shares	**(14)**	(11)	**(39)**	(31)
Distributions paid to subsidiaries' non-controlling interests	**(75)**	(54)	**(204)**	(126)
Principal payments on lease liabilities	**(3)**	(2)	**(8)**	(6)
FCF(3)	**228**	393	**769**	646

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

Key Non-IFRS Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted EBITDA

As at	Sept. 30, 2023	Dec. 31, 2022
Period-end long-term debt[(1)]	**3,559**	3,653
Exchangeable securities	**343**	339
Less: Cash and cash equivalents[(2)]	**(1,231)**	(1,118)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[(3)]	**671**	671
Other[(4)]	**(20)**	(20)
Adjusted net debt[(5)]	**3,322**	3,525
Adjusted EBITDA[(6)]	**1,884**	1,634
Adjusted net debt to adjusted EBITDA(times)	**1.8**	2.2

(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 consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including those classified as debt.
(4) Includes principal portion of TransAlta OCP restricted cash ($17 million for the period ended Sept. 30, 2023) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial Position).
(5) The tax equity financing for the Skookumchuck wind facility, an equity accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS. 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 internally and evaluated by management 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 3.5 times. Our adjusted net debt to adjusted EBITDA ratio for Sept. 30, 2023 was lower compared to Dec. 31, 2022, as a result of higher adjusted EBITDA, debt repayments and higher cash and cash equivalents.

2023 Outlook

Our annual outlook continues to highlight strong cash flow expectations for 2023 and, as a result, in the second quarter we revised our 2023 full year financial guidance upwards for both adjusted EBITDA and FCF to reflect stronger market conditions and solid operational performance. Our fleet remains well positioned to capture the ongoing strength that we see in the Alberta merchant market. The Company is focused on redeploying these cash flows towards growing our contracted clean electricity asset base.

The Company does not expect changes in our expectations of key financial targets and assumptions for 2023 as a result of the Arrangement where 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. Refer to the Significant and Subsequent Events section of this MD&A for more details.

The following table outlines our updated expectations on key financial targets and related assumptions for 2023 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	Updated Target 2023	Original Target 2023	2022 Actuals
Adjusted EBITDA(1)(2)	$1,700 million - $1,800 million	$1,200 million -$1,320 million	$1,634 million
FCF(1)(2)	$850 million - $950 million	$560 million - $660 million	$961 million
Dividend	no change	$0.22 per share annualized	$0.20 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.

(2) During the second quarter of 2023, the Company revised and increased our 2023 guidance for adjusted EBITDA and FCF based on the strong financial performance attained to date and our expectations for the balance of the year.

Range of key 2023 power and gas price assumptions

Market	Updated 2023 Assumptions	2023 Original Assumptions
Alberta Spot ($/MWh)	$150 to $170	$105 to $135
Mid-C Spot (US$/MWh)	US$90 to US$100	US$75 to US$85
AECO Gas Price ($/GJ)	$2.50	$4.60

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/- $1 million impact on adjusted EBITDA for 2023.

Other assumptions relevant to the 2023 outlook

	Updated 2023 Expectations	2023 Original Expectations
Sustaining capital	no change	$140 million - $170 million
Energy Marketing gross margin	$130 million - $150 million	$90 million - $110 million

Alberta Hedging

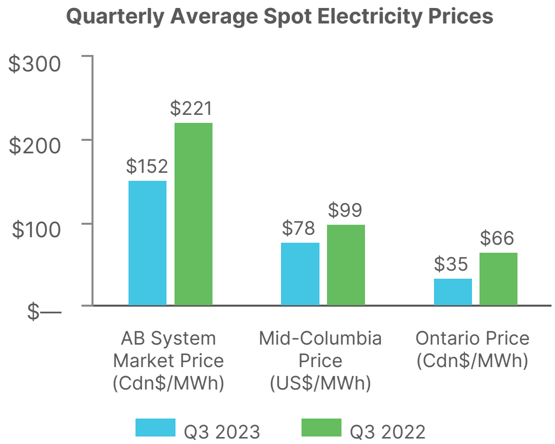
Range of hedging assumptions	Q4 2023	Full year 2024
Hedged production (GWh)	1,697	6,642
Hedge price ($/MWh)	$89	$84
Hedged gas volumes (GJ)	17 million	59 million
Hedge gas prices ($/GJ)	$2.34	$2.73

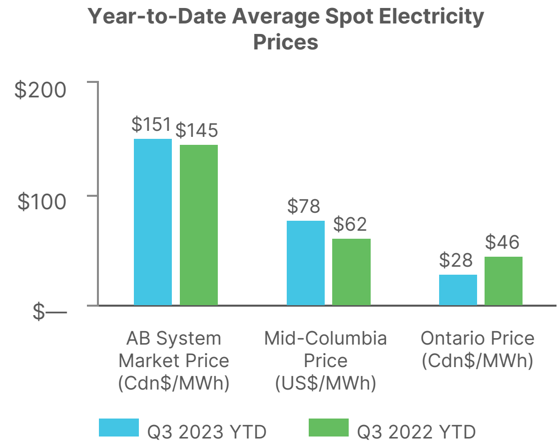
Refer to the 2023 Financial Outlook section in our 2022 Annual MD&A for further details relating to our Outlook and related assumptions.

Operations

The following provides an update to our assumptions included in the 2023 Outlook.

Market Pricing

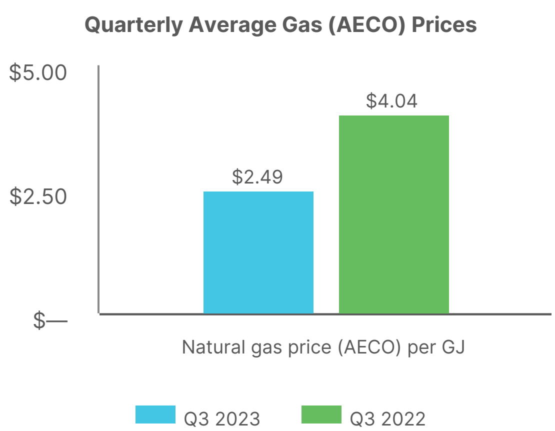


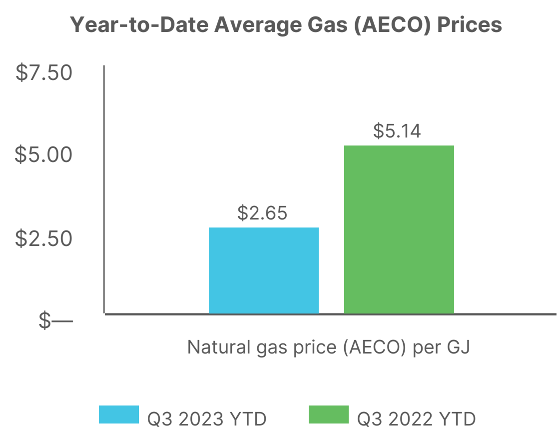


For the three months ended Sept. 30, 2023, spot electricity prices in Alberta and the Pacific Northwest were weaker compared to the same period in 2022 due to lower natural gas prices.

For the nine months ended Sept. 30, 2023, spot electricity prices in Alberta and the Pacific Northwest were higher compared to 2022. Higher prices in Alberta were due to tighter supply conditions from lower net electricity imports that resulted from stronger prices in adjacent markets and the reduction of import transmission capacity by the AESO. Stronger pricing in the Pacific Northwest has been driven by lower than normal hydrology for the region.

Ontario power prices for 2023 are expected to be lower than 2022 due to lower natural gas prices despite ongoing nuclear refurbishment outages.





AECO natural gas prices for the nine months ended Sept. 30, 2023, were lower than for the same periods in 2022 mainly due to improved production and storage levels in Alberta and North America.

The objective of our portfolio management strategy in Alberta is to balance opportunity and risk and to deliver optimization strategies that contribute to our total investment, which includes a return of and on invested capital. We can be more or less hedged in a given period, and we expect to realize our annual targets through a combination of forward hedging and selling generation into the spot market. The assets within the Alberta electricity portfolio are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind, energy storage and thermal facilities. Financial hedging is a key component of cash flow certainty and the hedges are primarily tied to our portfolio of gas assets and opportunistically allocated to our portfolio of hydro facilities rather than a single facility.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

	Spend for 3 months ended Sept. 30, 2023	9 months ended Sept. 30, 2023	Expected spend in 2023
Total sustaining capital	**36**	**100**	140-170

Total sustaining capital expenditures for the three and nine months ended Sept. 30, 2023, were $9 million and $25 million higher, respectively, compared to the same periods in 2022, mainly due to higher spending on leasehold improvements and information technology associated with the relocation of the Company's head office and planned major maintenance at the gas facilities.

The Kent Hills foundation rehabilitation capital expenditure has been segregated from our sustaining capital range due to the extraordinary and rare nature of this expenditure.

Kent Hills Rehabilitation

The Kent Hills 1 and 2 wind facilities were taken out of operation following the tower failure event that occurred in September 2021. This event resulted in approximately 150 MW of gross production being taken offline temporarily as the Company replaces all 50 turbine foundations. The extended outage is expected to result in foregone revenue of approximately $3 million per month on an annualized basis (to the extent all 50 turbines at the Kent Hills 1 and 2 wind facilities are offline), based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service.

Rehabilitation of the Kent Hills 1 and 2 wind facilities is well underway. All foundations have now been poured and all turbines have been fully reassembled. Turbines are being commissioned and returned to service as they are completed. To date 36 turbines have been placed back in operation and the remaining turbines are expected to return to service by the end of the fourth quarter of 2023. The current estimate of the total capital expenditures is approximately $157 million, inclusive of insurance proceeds. Capital expenditures include amounts for opportunistic blade repairs stemming from condition assessments enabled by the rehabilitation program.

During the first quarter of 2023, the Company filed and served a statement of claim in the New Brunswick Court of King’s Bench against certain defendants who the Company believes are responsible for, or contributed to, the failure of the turbine foundations at the Kent Hills 1 and 2 wind facilities. The claim seeks damages for lost profits, replacement costs, and other related costs to perform the remediation of Kent Hills 1 and 2, net of any insurance recoveries. The ability to recover any amounts is uncertain at this time.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. As at Sept. 30, 2023, we had access to $2.6 billion in liquidity, including $1.2 billion in cash; in excess of the funds required for committed growth, sustaining capital and productivity projects. On Oct. 5, 2023, $800 million of cash was used for the TransAlta Renewables transaction. Refer to the Significant and Subsequent Events section of this MD&A for more details.

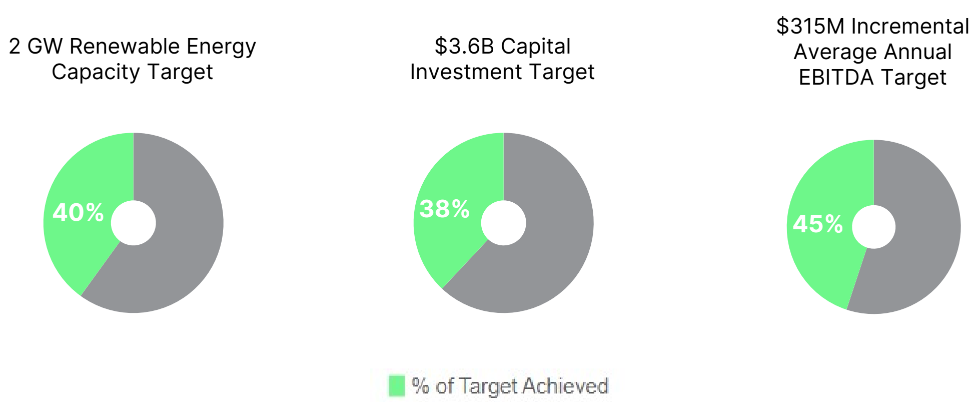
Strategy and Capability to Deliver Results

Our goal is to be a leading customer-centred electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high-quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customers' needs for clean, safe, low-cost, and reliable electricity and providing operational excellence and continuous improvement in everything we do.

The Company's focus remains on renewable generation and storage solutions for customers, which is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely by companies seeking to achieve their ESG ambitions. The Company also continues to evaluate and pursue natural gas generating assets to support reliability which will be required to facilitate the energy transition, including the Company's evaluation of the Pinnacle 1&2 project in Alberta as well contracted behind the fence generation opportunities in Australia to meet our customer electricity requirements. For additional information on regulatory developments, refer to the Regulatory Updates section of this MD&A.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind and solar technologies, to increase to 70 per cent by the end of 2025. The Company has a long-term decarbonization goal of net-zero by 2045 target. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and asset-level financing.

As of Nov. 6, 2023, we continue to make progress towards achieving the targets of the Clean Electricity Growth Plan.



Our progress towards achieving our strategic targets is summarized below:

Strategic Targets

Goals	Target	Results	Comments
Accelerate Growth in Customer-centered Renewables and Storage	Deliver 2 GW of renewable capacity with an estimated capital investment of $3.6 billion by the end of 2025.	On track	Construction projects for 548 MW of renewable capacity and transmission is currently underway and expected to reach commercial operations in the fourth quarter of 2023 and the first quarter of 2024. In August, the 130 MW Garden Plain facility reached commercial operations. The facility is fully contracted with Pembina Pipeline Corporation and PepsiCo Canada, with a weighted average contract life of approximately 17 years. The Company is currently advancing an additional 418 MW of advanced-stage projects towards final investment decision. In October, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, direct or indirectly, by the Company. The transaction provided economic contribution from an incremental 1.2 GW of generating capacity and increased the proportionate contractedness of the Company.
	Deliver incremental average annual EBITDA of $315 million.	On track	The cumulative progress towards our incremental EBITDA target is approximately $141 million. This comprises the acquisition of the North Carolina Solar project, the recently completed Garden Plain facility as well as the 548 MW of growth and transmission projects that are currently in the construction stage. The TransAlta Renewables acquisition will increase TransAlta's proportional EBITDA from renewables sources by an additional $100 million - $120 million that will be retained by TransAlta shareholders.
	Expand the Company's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet between 2025 and 2030.	On track	The Company is actively developing our pipeline. In the third quarter of 2023, the Company increased capacity at the Sunhills solar project by 55 MW and added 131 MW to its US and Australian list of prospects.
Take a Targeted Approach to Diversification	Grow our asset base in our core geographies of Canada, Australia and the US to realize diversification and value creation.	On track	The Company has successfully added new contracted renewable assets in each of its three core geographies and increased proportionate contractedness through the acquisition of the outstanding shares of TransAlta Renewables not owned, directly or indirectly, by TransAlta Renewables. We have diversified within the US market through our North Carolina Solar facility acquisition in 2021 and the new Oklahoma investments, which added three new investment-grade customers in 2022 and 2021.
Maintain Our Financial Strength and Capital Allocation Discipline	Deliver strong cash flow from our existing portfolio to allocate towards our funding priorities including growth, dividends and share buybacks.	On track	The Company had liquidity of $2.6 billion as at Sept. 30, 2023. The Company returned $71 million to shareholders through share buybacks in 2023 under our NCIB. The Company increased the annual common share dividend by 10 per cent to $0.22 per year effective Jan. 1, 2023.
Define the Next Generation of Energy Solutions and Technologies	Meet the needs of our customers and communities through the implementation of innovative energy solutions and parallel investments in new complementary sectors by the end of 2025.	On track	The Company established an Energy Innovation team to progress our goals in this area. The team has completed an equity investment in Ekona Power Inc., an early-stage hydrogen production company, in order to pursue commercialization of low cost, net-zero aligned hydrogen. The Company also committed to invest US$25 million over the next four years in the Energy Impact Partners Frontier Fund, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions. In total, the Company invested $15 million to this fund as at Sept. 30, 2023.

Strategic Targets

Goals	Target	Results	Comments
Lead in ESG Policy Development	Actively participate in policy development to ensure the electricity that we provide contributes to emissions reduction, grid reliability and competitive energy prices to enable the successful evolution of the markets in which we operate and compete.	On track	The Company is actively engaging the Government of Canada and Government of Alberta regarding the proposed federal Clean Electricity Regulations, as well as market and approval changes under review in Alberta. TransAlta continues to provide input regarding how to achieve emissions reductions while maintaining reliability and affordability. The Company continues to work with the Government of Canada on the design details of the investment tax credits and clean technology funding provided through the Government of Canada, as well as exploring funding opportunities through the Government of Alberta.

Growth

In August 2023, the Garden Plain wind facility was commissioned. The completion of the Garden Plain wind facility added 130 MW to our gross installed capacity. The facility is fully contracted. We anticipate that the Garden Plain wind facility will contribute approximately $13 - $14 million of average annual EBITDA.

In addition to the projects currently under construction, we continue to expand our pipeline of potential growth projects. Our pipeline includes 418 MW of advanced-stage development projects along with 4,377 MW to 5,477 MW of projects in earlier stages of development.

During the nine months ended Sept. 30, 2023, we expanded our pipeline of potential growth projects by 816 MW.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the US, along with acquisitions in markets in which we have existing operations.

Projects under Construction

The following projects have been approved by the Board of Directors, have executed PPAs and are currently under construction. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore project financing or tax equity as a long-term financing solution on an asset-by-asset basis.

We are continually monitoring the timing and costs on our projects under construction. Our US projects have seen delays and increase costs attributable to the complexity and completion of transmission interconnections. We continue to advance the interconnections and expect the interconnections to be completed by the end of 2023.

Project	Type	Region	MW	Total project (millions) Estimated spend		Spent to date	Target completion date	PPA Term(1)	Average annual EBITDA(2)	Status
United States										
White Rock	Wind	OK	300	US$510	— US$530	US$431	Q1 2024	—	US$53-US$57	• Long-term PPAs executed • All major equipment delivered • Construction activities are underway
Horizon Hill	Wind	OK	200	US$330	— US$340	US$277	Q1 2024	—	US$31-US$33	• Long-term PPA executed • All major equipment delivered • Turbine assembly is complete • Construction activities are underway
Australia										
Northern Goldfields	Hybrid Solar	WA	48	AU$69	— AU$73	AU$65	Q4 2023	16	AU$9 - AU$10	• Construction complete • Commissioning is now underway • Completion expected in the fourth quarter of 2023
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$54	— AU$57	AU$42	Q4 2023	15	AU$6 - AU$7	• Transmission line and transformer installation complete • Remaining construction activities are progressing • On track to be completed in the fourth quarter of 2023
Total(3)			**548**	**$1,228**	**— $1,274**	**1,225**			**$125 - $135**	

(1) The PPA term is confidential for the White Rock wind projects and 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 was converted using a Canadian dollar forward exchange rate for 2023. Spend to date was converted using the period end closing rate.

Advanced-Stage Development

These projects have detailed engineering, advanced position in the interconnection queue and are progressing offtake opportunities. The following table shows the pipeline of future growth projects currently under advanced-stage development:

Project[(1)]	Type	Region	Target completion date	MW	Estimated spend	Average annual EBITDA[(3)]
Tempest	Wind	Alberta	2026	100	$250-$270	$23-$25
SCE Capacity Expansion	Gas	Western Australia	2025	94	AU$210-AU$230	AU$28-AU$32
WaterCharger	Battery Storage	Alberta	2025	180	$150-$170[(2)]	$15-$17
Australia Transmission Expansion	Transmission	Western Australia	2025	n/a	AU$70-AU$75	AU$7-AU$8
Pinnacle 1 & 2	Gas	Alberta	2025	44	$60-$70	$12-$15
Total[(4)]				**418**	**$715 - $788**	**$82 - $93**

(1) Projects in advanced-stage development are progressing towards final investment decision and have not received final approval from the Board of Directors at time of reporting.
(2) Estimated spend is net of government funding and anticipated tax credits.
(3) 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.
(4) Total expected spending and average annual EBITDA was converted using a Canadian dollar forward exchange rate for 2023.

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 completion date (1)	MW
Canada				
Riplinger Wind	Wind	Alberta	2027	300
Red Rock	Wind	Alberta	2028	100
Willow Creek 1	Wind	Alberta	2028	70
Willow Creek 2	Wind	Alberta	2028	70
Sunhills Solar	Solar	Alberta	2027	170
McNeil Solar	Solar	Alberta	2026	57
Canadian Battery opportunity	Battery	New Brunswick	2026	10
Canadian Wind opportunities	Wind	Various	2027+	370
Tent Mountain Pumped Storage(2)	Hydro	Alberta	2028-2030	160
Brazeau Pumped Hydro	Hydro	Alberta	2037	300-900
Alberta Thermal Redevelopment	Various	Alberta	TBD	250-500
			Total	**1,857 - 2,707**
United States				
Old Town	Wind	Illinois	2026	185
Trapper Valley	Wind	Wyoming	2028	225
Monument Road	Wind	Nebraska	2025	152
Dos Rios	Wind	Oklahoma	2026	242
Canadian River	Wind	Oklahoma	2027	250
Prairie Violet	Wind	Illinois	2027	130
Big Timber	Wind	Pennsylvania	2027	50
Square Top Solar	Solar	Oklahoma	2027	195
Swan Creek	Wind	Nebraska	2026	126
Other Wind and Solar prospects	Wind and Solar	Various	2025+	430
Centralia site redevelopment	Various	Washington	TBD	250-500
			Total	**2,235 - 2,485**
Australia				
Australian prospects	Gas, Solar, Wind	Western Australia	2025+	235
South Hedland Solar	Solar	Western Australia	2026	50
			Total	**285**
Canada, United States and Australia			**Total**	**4,377 - 5,477**

(1) Potential completion date is to be determined ("TBD").
(2) This represents the Company's 50 per cent interest in Tent Mountain. See the Significant and Subsequent Events section of this MD&A for more details.

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. The following were material changes in estimates in the quarter:

Decommissioning and Restoration Provisions

The Company recognizes provisions for decommissioning obligations. Initial decommissioning provisions and subsequent changes thereto, are determined using the Company’s best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement.

In the nine months ended Sept. 30, 2023, the decommissioning and restoration provision decreased by $68 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Energy Transition assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work.Operating assets included in PP&E decreased by $15 million and $53 million was recognized as an impairment reversal in net earnings related to retired assets.

For the nine months ended Sept. 30, 2023, revisions in discount rates decreased the decommissioning and restoration provision by $11 million due to an increase in discount rates, largely driven by increases in long-term market benchmark rates. On average, discount rates increased with rates ranging from 7.3 to 10.0 per cent as at Sept. 30, 2023 from 7.0 to 9.7 per cent as at Dec. 31, 2022. This has resulted in a corresponding increase in PP&E of $4 million on operating assets and recognition of a $7 million impairment charge in net earnings related to retired assets. Refer to Note 15 of the unaudited condensed consolidated financial statements for the three and nine months ended Sept. 30, 2023.

Reversals of Impairment of PP&E

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

During the three and nine months ended Sept. 30, 2023, the Company recognized asset impairment charges, net of impairment reversals, of $6 million and asset impairment reversals, net of impairment charges, of $14 million, respectively. Refer to Note 5 of the unaudited condensed consolidated financial statements for the three and nine months ended Sept. 30, 2023.

Change in Estimate - Useful Lives

During the third quarter of 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes made based on future operating expectations of the assets. This resulted in a decrease of $46 million in depreciation expense recognized in the third quarter of 2023.

Accounting Changes

Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board (“IASB”) issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

Future Accounting Changes

Please refer to Note 3 of the audited annual consolidated financial statements for the future accounting policies impacting the Company. For the three and nine months ended Sept. 30, 2023, no additional future accounting policy changes impacting the Company were identified.

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 2022 Annual MD&A and Note 11 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2022.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2022 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 greenhouse gas ("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 were published in Canada Gazette Part I on Aug. 19, 2023. A seventy five day formal comment period closed on Nov. 2, 2023, and 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 a consultation to advance key budget priorities, including the Clean Technology ITC, Clean Manufacturing ITC and ITC for Carbon Capture Utilization and Storage. Legislation is expected to be finalized in 2024.

Alberta

On April 19, 2023, the Government of Alberta released the Emissions Reduction and Energy Development Plan, which commits to 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 Aug. 3, 2023, the Government of Alberta announced that the province will be pausing Alberta Utilities Commission approvals for new renewable energy development projects over one megawatt until Feb. 29, 2024. The pause will not impact the Tempest or WaterCharger projects, which have already secured AUC power plant approvals. Concurrently, the Alberta Utilities Commission was directed to conduct an inquiry on renewable development that will consider the impacts of renewable power generation on land use, system reliability, and reclamation. The Company will participate in the inquiry and in any associated consultations that will be held by the Government of Alberta in relation to renewable project developments in the province. In tandem, the AESO continues to proceed with the Market Pathways Initiative, that seeks to identify the key challenges that Alberta's electricity system will face in the future and make recommendations on changes to the market design to achieve reliability and affordability. This work will proceed through to the third quarter of 2024.

United States

On March 21, 2022, the U.S. Securities and Exchange Commission ("SEC") released proposed rules to enhance and standardize climate-related disclosure for investors. The proposed rules cover climate risk governance and risk management, disclosure of material impacts over all time horizons, impacts on business models, and the impact of climate-related events. Both the Canadian Securities Administrators and the SEC have signalled that they are expected to release their climate disclosure rules in 2023. The Company is prepared to assess our disclosures to ensure compliance once the new rules are in force.

On Aug. 16, 2022, the Inflation Reduction Act ("IRA") of 2022 was signed into law by President Biden. This Act will invest approximately US$369 billion in Energy Security and Climate Change programs over the next 10 years. The administration estimates this funding will help reduce national carbon emissions by approximately 40 per cent by 2030, lower energy costs and increase clean energy production. The Treasury Department released a roadmap on March 22, 2023, to provide additional certainty regarding the timing for remaining guidance on the various components of the renewables and hydrogen tax incentives in the IRA. Additional guidance on the IRA Energy Community Tax Credit Bonus (for ITC and PTC) for projects, facilities and technologies located in energy communities was released on April 4, 2023, helping to identify areas that may be eligible for the energy communities bonus. It includes areas that have significant employment or local tax revenues from fossil fuels and higher than average unemployment. On June 14, 2023, the Treasury Department released guidance relating to domestic content, direct pay and transferability of tax credits. The guidance for low-income communities and energy communities was released Aug. 10, 2023. As of the first anniversary of the IRA, Aug. 16, 2023, the Department of Treasury has Released 38 Guidance/Rules for the ITC/PTC cross-cutting bonus provisions.

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.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the three and nine months ended Sept. 30, 2023, the majority of our workforce supporting and executing our ICFR and DC&P continue to work on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with IFRS. Management has used the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) in order to assess the effectiveness of the Company's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under applicable securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and as such may not prevent or detect all misstatements and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Sept. 30, 2023, 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 Sept. 30		9 months ended Sept. 30	
Unaudited	**2023**	2022	**2023**	2022
Revenues (Note 3)	**1,017**	929	**2,731**	2,122
Fuel and purchased power (Note 4)	**269**	348	**782**	817
Carbon compliance (Note 12)	**28**	23	**85**	51
Gross margin	**720**	558	**1,864**	1,254
Operations, maintenance and administration (Note 4)	**131**	135	**389**	364
Depreciation and amortization (Note 14)	**140**	179	**489**	411
Asset impairment charges (reversals) (Note 5)	**(58)**	70	**(74)**	4
Taxes, other than income taxes	**8**	8	**26**	25
Net other operating income	**(11)**	(11)	**(34)**	(48)
Operating income	**510**	177	**1,068**	498
Equity income	**—**	1	**1**	5
Finance lease income	**2**	4	**10**	15
Net interest expense (Note 6)	**(53)**	(66)	**(168)**	(195)
Foreign exchange gain (loss)	**(5)**	6	**—**	17
Gain (loss) on sale of assets and other	**(1)**	4	**4**	6
Earnings before income taxes	**453**	126	**915**	346
Income tax expense (Note 7)	**34**	30	**65**	103
Net earnings	**419**	96	**850**	243
Net earnings attributable to:				
TransAlta shareholders	**386**	72	**754**	188
Non-controlling interests (Note 8)	**33**	24	**96**	55
	419	96	**850**	243
Net earnings attributable to TransAlta shareholders	**386**	72	**754**	188
Preferred share dividends (Note 18)	**14**	11	**26**	21
Net earnings attributable to common shareholders	**372**	61	**728**	167
Weighted average number of common shares outstanding in the period *(millions)*	**263**	271	**265**	271
Net earnings per share attributable to common shareholders, basic and diluted (Note 17)	**1.41**	0.23	**2.75**	0.62

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2023**	2022	**2023**	2022
Net earnings	**419**	96	**850**	243
Other comprehensive income (loss)				
Net actuarial gains on defined benefit plans, net of tax[1]	**12**	—	**15**	36
Fair value loss on third-party investments, net of tax	**—**	(1)	**—**	(1)
Total items that will not be reclassified subsequently to net earnings (loss)	**12**	(1)	**15**	35
Gains (losses) on translating net assets of foreign operations, net of tax	**4**	24	**(9)**	18
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**(7)**	(25)	**2**	(28)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[3]	**20**	(100)	**72**	(251)
Reclassification of losses on derivatives designated as cash flow hedges to net earnings, net of tax[4]	**16**	39	**48**	21
Total items that will be reclassified subsequently to net earnings (loss)	**33**	(62)	**113**	(240)
Other comprehensive income (loss)	**45**	(63)	**128**	(205)
Total comprehensive income	**464**	33	**978**	38
Total comprehensive income attributable to:				
TransAlta shareholders	**441**	—	**907**	44
Non-controlling interests (Note 8)	**23**	33	**71**	(6)
	464	33	**978**	38

(1) Net of income tax expense of $5 million for the three and nine months ended Sept. 30, 2023 (Sept. 30, 2022 – nil and $11 million expense).

(2) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2023 (Sept. 30, 2022 – $3 million and $4 million recovery).

(3) Net of income tax expense of $4 million and $19 million for the three and nine months ended Sept. 30, 2023 (Sept. 30, 2022 – $29 million and $72 million recovery).

(4) Net of reclassification of income tax expense of $4 million and $14 million for the three and nine months ended Sept. 30, 2023 (Sept. 30, 2022 – $10 million and $5 million recovery).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	Sept. 30, 2023	Dec. 31, 2022
Current assets		
Cash and cash equivalents	**1,231**	1,134
Restricted cash (Note 16)	**63**	70
Trade and other receivables (Note 9)	**834**	1,589
Prepaid expenses (Note 22)	**59**	33
Risk management assets (Note 10 and 11)	**143**	709
Inventory (Note 12)	**180**	157
Assets held for sale	**—**	22
	2,510	3,714
Non-current assets		
Investments (Note 13)	**137**	129
Long-term portion of finance lease receivables	**116**	129
Risk management assets (Note 10 and 11)	**84**	161
Property, plant and equipment (Note 14)		
Cost	**14,505**	14,012
Accumulated depreciation	**(8,828)**	(8,456)
	5,677	5,556
Right-of-use assets	**120**	126
Intangible assets	**228**	252
Goodwill	**464**	464
Deferred income tax assets	**19**	50
Other assets	**165**	160
Total assets	**9,520**	10,741
Current liabilities		
Bank overdraft	**—**	16
Accounts payable and accrued liabilities (Note 9)	**687**	1,346
Current portion of decommissioning and other provisions (Note 15)	**39**	70
Risk management liabilities (Note 10 and 11)	**335**	1,129
Current portion of contract liabilities	**6**	8
Income taxes payable	**16**	73
Dividends payable (Note 17 and 18)	**15**	68
Current portion of long-term debt and lease liabilities (Note 16)	**529**	178
	1,627	2,888
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 16)	**3,030**	3,475
Exchangeable securities	**743**	739
Decommissioning and other provisions (Note 15)	**614**	659
Deferred income tax liabilities	**367**	352
Risk management liabilities (Note 10 and 11)	**222**	333
Contract liabilities	**11**	12
Defined benefit obligation and other long-term liabilities	**243**	294
Equity		
Common shares (Note 17)	**2,808**	2,863
Preferred shares (Note 18)	**942**	942
Contributed surplus	**33**	41
Deficit	**(1,822)**	(2,514)
Accumulated other comprehensive loss	**(69)**	(222)
Equity attributable to shareholders	**1,892**	1,110
Non-controlling interests (Note 8)	**771**	879
Total equity	**2,663**	1,989
Total liabilities and equity	**9,520**	10,741

Commitments and contingencies (Note 19)
Subsequent events (Note 22)
See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited **9 months ended Sept. 30, 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	**—**	**—**	**—**	**754**	**—**	**754**	**96**	**850**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(7)**	**(7)**	**—**	**(7)**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**120**	**120**	**—**	**120**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**15**	**15**	**—**	**15**
Intercompany and third-party FVTOCI investments	**—**	**—**	**—**	**—**	**25**	**25**	**(25)**	**—**
Total comprehensive income	**—**	**—**	**—**	**754**	**153**	**907**	**71**	**978**
Common share dividends (Note 17)	**—**	**—**	**—**	**(30)**	**—**	**(30)**	**—**	**(30)**
Preferred share dividends (Note 18)	**—**	**—**	**—**	**(26)**	**—**	**(26)**	**—**	**(26)**
Shares purchased under normal course issuer bid ("NCIB") (Note 17)	**(65)**	**—**	**—**	**(6)**	**—**	**(71)**	**—**	**(71)**
Effect of share-based payment plans	**10**	**—**	**(8)**	**—**	**—**	**2**	**—**	**2**
Distributions declared to non-controlling interests (Note 8)	**—**	**—**	**—**	**—**	**—**	**—**	**(179)**	**(179)**
Balance, Sept. 30, 2023	**2,808**	**942**	**33**	**(1,822)**	**(69)**	**1,892**	**771**	**2,663**

9 months ended Sept. 30, 2022	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2021	2,901	942	46	(2,453)	146	1,582	1,011	2,593
Net earnings	—	—	—	188	—	188	55	243
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(10)	(10)	—	(10)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(230)	(230)	—	(230)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	36	36	—	36
FVOCI investments	—	—	—	—	60	60	(61)	(1)
Total comprehensive income (loss)	—	—	—	188	(144)	44	(6)	38
Common share dividends paid	—	—	—	(27)	—	(27)	—	(27)
Preferred share dividends paid	—	—	—	(21)	—	(21)	—	(21)
Shares purchased under NCIB program (Note 17)	(29)	—	—	(5)	—	(34)	—	(34)
Effect of share-based payment plans	7	—	(13)	—	—	(6)	—	(6)
Distributions declared to non-controlling interests (Note 8)	—	—	—	—	—	—	(126)	(126)
Balance, Sept. 30, 2022	2,879	942	33	(2,318)	2	1,538	879	2,417

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2023**	2022	**2023**	2022
Operating activities				
Net earnings	**419**	96	**850**	243
Depreciation and amortization	**140**	179	**489**	411
Gain (loss) on sale of assets and other	**1**	(4)	**(3)**	(5)
Accretion of provisions (Note 6 and 15)	**10**	16	**37**	35
Decommissioning and restoration costs settled (Note 15)	**(6)**	(9)	**(22)**	(23)
Deferred income tax expense (recovery) (Note 7)	**(3)**	20	**10**	68
Unrealized loss (gain) from risk management activities	**(174)**	151	**(87)**	111
Unrealized foreign exchange (gain) loss	**(30)**	6	**(28)**	7
Provisions	**(3)**	(8)	**(3)**	(4)
Asset impairment charges (reversals) (Note 5)	**(58)**	70	**(74)**	4
Equity (income) loss, net of distributions from investments	**3**	—	**5**	(2)
Other non-cash items	**27**	(37)	**(9)**	(67)
Cash flow from operations before changes in working capital	**326**	480	**1,165**	778
Change in non-cash operating working capital balances	**355**	(276)	**(11)**	(252)
Cash flow from operating activities	**681**	204	**1,154**	526
Investing activities				
Additions to property, plant and equipment (Note 14)	**(165)**	(280)	**(641)**	(481)
Additions to intangible assets	**(3)**	(4)	**(9)**	(27)
Restricted cash (Note 16)	**(22)**	(22)	**5**	3
Repayment from loan receivable	**3**	4	**8**	14
Investments (Note 13)	**—**	—	**(10)**	—
Proceeds on sale of property, plant and equipment	**1**	10	**28**	12
Realized gain on financial instruments	**5**	9	**18**	8
Decrease in finance lease receivable	**14**	12	**40**	34
Other	**(7)**	6	**(15)**	13
Change in non-cash investing working capital balances	**(50)**	90	**(15)**	83
Cash flow used in investing activities	**(224)**	(175)	**(591)**	(341)
Financing activities				
Net increase (decrease) in borrowings under credit facilities (Note 16)	**(55)**	—	**32**	—
Repayment of long-term debt (Note 16)	**(22)**	(21)	**(131)**	(80)
Issuance of long-term debt (Note 16)	**39**	—	**39**	—
Dividends paid on common shares (Note 17)	**(14)**	(14)	**(44)**	(41)
Dividends paid on preferred shares (Note 18)	**(14)**	(11)	**(39)**	(31)
Repurchase of common shares under NCIB (Note 17)	**—**	(10)	**(73)**	(28)
Proceeds on issuance of common shares	**—**	—	**4**	1
Realized loss on financial instruments	**(32)**	—	**(32)**	—
Distributions paid to subsidiaries' non-controlling interests (Note 8)	**(75)**	(54)	**(204)**	(126)
Decrease in lease liabilities	**(3)**	(2)	**(8)**	(6)
Financing fees and other	**1**	(2)	**1**	(4)
Cash flow used in financing activities	**(175)**	(114)	**(455)**	(315)
Cash flow from (used in) operating, investing and financing activities	**282**	(85)	**108**	(130)
Effect of translation on foreign currency cash	**(3)**	3	**(11)**	(1)
Increase (decrease) in cash and cash equivalents	**279**	(82)	**97**	(131)
Cash and cash equivalents, beginning of period	**952**	898	**1,134**	947
Cash and cash equivalents, end of period	**1,231**	816	**1,231**	816
Cash taxes paid	**1**	10	**71**	53
Cash interest paid	**61**	52	**200**	159

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.sedar.com 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 Nov. 6, 2023.

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 the three and nine months ended Sept. 30, 2023, there were changes in estimates relating to asset impairment charges (reversals) (Note 5), useful lives (Note 14), and decommissioning and restoration provisions (Note 15).

Refer to Note 2(P) of the Company's 2022 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, 2022, except for the adoption of new standards effective as of Jan. 1, 2023.

A. Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board ("IASB") issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

B. Future Accounting Changes

Please refer to Note 3 of the audited annual consolidated financial statements for the future accounting policies impacting the Company. For the three and nine months ended Sept. 30, 2023, no additional future accounting policy changes impacting the Company were identified.

3. Revenue

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 Sept. 30, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	8	30	89	5	—	—	132
Environmental attributes(1)	—	3	—	—	—	—	3
Revenue from contracts with customers	8	33	89	5	—	—	135
Revenue from leases(2)	—	—	10	—	—	—	10
Revenue from derivatives and other trading activities(3)	12	(2)	26	60	86	—	182
Revenue from merchant sales	139	25	395	123	—	—	682
Other(4)	4	2	2	—	—	—	8
Total revenue	163	58	522	188	86	—	1,017
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	3	—	4	—	—	7
Over time	8	30	89	1	—	—	128
Total revenue from contracts with customers	8	33	89	5	—	—	135

(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 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 Sept. 30, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	11	37	124	—	—	—	172
Environmental attributes[1]	—	3	—	—	—	—	3
Revenue from contracts with customers	11	40	124	—	—	—	175
Revenue from leases[2]	—	—	12	—	—	—	12
Revenue from derivatives and other trading activities[3]	—	(57)	(286)	60	54	1	(228)
Revenue from merchant sales	252	25	518	171	—	—	966
Other[4]	2	3	4	—	—	(5)	4
Total revenue	265	11	372	231	54	(4)	929
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	3	—	2	—	—	5
Over time	11	37	124	(2)	—	—	170
Total revenue from contracts with customers	11	40	124	—	—	—	175

(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 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.

9 months ended Sept. 30, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	**24**	**141**	**282**	**10**	**—**	**—**	**457**
Environmental attributes[1]	**9**	**23**	**—**	**—**	**—**	**—**	**32**
Revenue from contracts with customers	**33**	**164**	**282**	**10**	**—**	**—**	**489**
Revenue from leases[2]	**—**	**—**	**27**	**—**	**—**	**—**	**27**
Revenue from derivatives and other trading activities[3]	**37**	**(2)**	**(132)**	**190**	**181**	**1**	**275**
Revenue from merchant sales	**378**	**76**	**1,085**	**376**	**—**	**—**	**1,915**
Other[4]	**8**	**11**	**6**	**—**	**—**	**—**	**25**
Total revenue	**456**	**249**	**1,268**	**576**	**181**	**1**	**2,731**
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	**9**	**23**	**—**	**9**	**—**	**—**	**41**
Over time	**24**	**141**	**282**	**1**	**—**	**—**	**448**
Total revenue from contracts with customers	**33**	**164**	**282**	**10**	**—**	**—**	**489**

(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 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.

9 months ended Sept. 30, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	29	155	340	6	—	—	530
Environmental attributes[1]	1	33	—	—	—	—	34
Revenue from contracts with customers	30	188	340	6	—	—	564
Revenue from leases[2]	—	—	20	—	—	—	20
Revenue from derivatives and other trading activities[3]	—	(91)	(359)	174	116	3	(157)
Revenue from merchant sales	411	83	925	253	—	—	1,672
Other[4]	6	15	7	—	—	(5)	23
Total revenue	447	195	933	433	116	(2)	2,122
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	1	33	—	8	—	—	42
Over time	29	155	340	(2)	—	—	522
Total revenue from contracts with customers	30	188	340	6	—	—	564

(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 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 classified by nature are as follows:

	3 months ended Sept. 30				**9 months ended Sept. 30**			
	2023		2022		**2023**		2022	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	**Fuel and purchased power**	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs	**89**	**—**	152	—	**270**	**—**	409	—
Coal fuel costs	**48**	**—**	49	—	**130**	**—**	100	—
Royalty, land lease, other direct costs	**5**	**—**	6	—	**19**	**—**	18	—
Purchased power	**127**	**—**	141	—	**363**	**—**	290	—
Salaries and benefits	**—**	**61**	—	66	**—**	**191**		180
Other operating expenses	**—**	**70**	—	69	**—**	**198**	—	184
Total	**269**	**131**	348	135	**782**	**389**	817	364

5. Asset Impairment Charges (Reversals)

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Segments:				
Hydro	**—**	15	**(10)**	21
Wind and Solar	**6**	14	**(4)**	35
Changes in decommissioning and restoration provisions on retired assets	**(64)**	41	**(60)**	(52)
Asset impairment charges (reversals)	**(58)**	70	**(74)**	4

Hydro

During the second quarter of 2023, internal valuations indicated the fair value less costs of disposal for two hydro facilities exceeded the carrying value due to a contract extension and changes in power price assumptions, which favourably impacted estimated future cash flows and resulted in a full recoverability test. As a result of the recoverability test an impairment reversal of $10 million was recognized. The recoverable amounts of $70 million in total were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement. The discount rate used in the fair value measurements was 6.32 per cent.

During the three and nine months ended Sept. 30, 2022, the Company recorded net impairment charges of $15 million and $21 million, respectively. During the second quarter of 2022, an impairment of $6 million was recorded on one of the hydro facilities primarily from an increase in discount rates. During the third quarter of 2022, two additional hydro facilities were impaired as a result of changes in key assumptions including significant increases in discount rates and changes in estimated future cash flows and pricing. The recoverable amounts of $89 million in total for these three assets were estimated based on fair value less cost of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement.

Wind and Solar

During the three and nine months ended Sept. 30, 2023, the Company recorded net impairment charges of $6 million and net impairment reversals of $4 million, respectively. During the first quarter of 2023, internal valuations indicated the fair value less costs of disposal of the assets exceeded the carrying value due to changes in power price assumptions for two wind facilities, which favourably impacted estimated future cash flows and resulted in a full recoverability test. As a result of the recoverability test an impairment reversal of $10 million was recognized.

During the third quarter of 2023, two wind facilities were impaired primarily due to unfavourable power price assumptions and changes in estimated future cash flows. An impairment charge of $13 million was recognized for these facilities. The recoverable amount of $130 million for these two assets was estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 6.89 to 7.03 per cent.

Also during the third quarter of 2023, an asset impairment reversal of $7 million was recognized for one wind facility, which was favourably impacted by changes in pricing and changes in estimated future cash flows. The recoverable amount of $287 million was estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement. The discount rate used in the fair value measurements was 6.80 per cent.

During the three and nine months ended Sept. 30, 2022, the Company recorded net impairment charges of $14 million and $35 million, respectively. During the second quarter of 2022, three wind facilities were impaired primarily as a result of an increase in discount rates. During the third quarter of 2022, two additional wind facilities and one solar facility were impaired as a result of changes in key assumptions including significant increases in discount rates and changes in estimated future cash flows. The recoverable amounts of $607 million for these six assets were estimated based on fair value less cost of disposal utilizing a discounted cash flow approach and is categorized as a Level III fair value measurement.

Changes in Decommissioning and Restoration Provisions

During 2023, the Company adjusted the expected timing on decommissioning and restoration for certain Gas and Energy Transition assets to optimize and maximize efficiencies by staging required reclamation work. This resulted in a decrease in the decommissioning and restoration provision related to retired assets of $53 million and a corresponding impairment reversal recognized for the nine months ended Sept. 30, 2023. In addition, there were increases in discount rates resulting in an impairment reversal of $7 million. Refer to Note 15 for further details.

6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Interest on debt	**51**	42	**152**	123
Interest on exchangeable debentures	**7**	7	**22**	22
Interest on exchangeable preferred shares[(1)]	**7**	7	**21**	21
Interest income	**(16)**	(7)	**(47)**	(14)
Capitalized interest (Note 14)	**(15)**	(4)	**(41)**	(8)
Interest on lease liabilities	**3**	1	**7**	4
Credit facility fees, bank charges and other interest	**6**	5	**17**	16
Tax shield on tax equity financing	**—**	(1)	**—**	(4)
Accretion of provisions (Note 15)	**10**	16	**37**	35
Net interest expense	**53**	66	**168**	195

(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 long-term debt and the exchangeable preferred share dividends are reported as interest expense. On Oct. 27, 2023, the Company declared a dividend of $7 million in aggregate on the Series I Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on Nov. 30, 2023.

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Current income tax expense	**37**	10	**55**	35
Deferred income tax expense related to the origination and reversal of temporary differences	**80**	20	**190**	168
Deferred income tax expense (recovery) related to temporary difference on investment in subsidiary	**—**	—	**1**	(7)
Deferred income tax recovery arising from unrecognized deferred income tax assets(1)	**(83)**	—	**(181)**	(93)
Income tax expense	**34**	30	**65**	103
Current income tax expense	**37**	10	**55**	35
Deferred income tax expense (recovery)	**(3)**	20	**10**	68
Income tax expense	**34**	30	**65**	103

(1) The Company's deferred income tax assets mainly relate to the tax benefits of losses associated with the Company's directly owned Canadian and US operations and other deductible differences. The Company undertakes an analysis of the recoverability of its tax assets on an ongoing basis. Adjustments to recognize or write-off deferred income tax assets arise from the Company's assessment of whether it is probable, or not, that sufficient future taxable income will be available to utilize the underlying tax losses. During the third quarter of 2023, the Company recorded a reversal of the write-down of deferred income tax asset related to certain Canadian operations as it is considered probable that sufficient future taxable income will be available to utilize the underlying tax losses.

8. Non-Controlling Interests

The Company’s subsidiaries with significant non-controlling interests are TransAlta Renewables Inc. ("TransAlta Renewables") and TransAlta Cogeneration L.P. The net earnings, distributions and equity attributable to TransAlta Renewables’ non-controlling interests include the 17 per cent non-controlling interest in Kent Hills Wind LP, which owns the 167 MW Kent Hills wind farm located in New Brunswick.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Net earnings (loss)				
TransAlta Cogeneration L.P.	**35**	32	**76**	45
TransAlta Renewables	**(2)**	(8)	**20**	10
	33	24	**96**	55
Total comprehensive income (loss)				
TransAlta Cogeneration L.P.	**35**	32	**76**	45
TransAlta Renewables	**(12)**	1	**(5)**	(51)
	23	33	**71**	(6)
Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**50**	29	**129**	51
TransAlta Renewables	**25**	25	**75**	75
	75	54	**204**	126

As at	Sept. 30, 2023	Dec. 31, 2022
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**93**	147
TransAlta Renewables	**678**	732
	771	879
Non-controlling interests (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

On Oct. 4, 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. See Note 22 Subsequent Events for more details.

9. Trade and Other Receivables and Accounts Payable

As at	Sept. 30, 2023	Dec. 31, 2022
Trade accounts receivable	**617**	1,165
Collateral provided (Note 11)	**170**	304
Current portion of finance lease receivables	**24**	52
Loan receivable	**—**	4
Income taxes receivable	**23**	64
Trade and other receivables	**834**	1,589

As at	Sept. 30, 2023	Dec. 31, 2022
Accounts payable and accrued liabilities	**666**	1,069
Interest payable	**21**	17
Collateral held (Note 11)	**—**	260
Accounts payable and accrued liabilities	**687**	1,346

10. 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 2022 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 Sept. 30, 2023, are as follows: Level I – $25 million net liability (Dec. 31, 2022 – $23 million net asset), Level II – $18 million net asset (Dec. 31, 2022 – $173 million net asset) and Level III – $330 million net liability (Dec. 31, 2022 – $782 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2023, 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 nine months ended Sept. 30, 2023 and 2022, respectively:

	9 months ended Sept. 30, 2023			9 months ended Sept. 30, 2022		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**(347)**	**(435)**	**(782)**	285	(126)	159
Changes attributable to:						
Market price changes on existing contracts	**(53)**	**59**	**6**	(346)	(371)	(717)
Change resulting from amended contract and market price changes on new contracts	**—**	**(24)**	**(24)**	—	(114)	(114)
Contracts settled	**214**	**253**	**467**	(37)	82	45
Change in foreign exchange rates	**2**	**1**	**3**	20	(6)	14
Transfers into (out of) Level III	**—**	**—**	**—**	—	2	2
Net risk management assets (liabilities) at end of period	**(184)**	**(146)**	**(330)**	(78)	(533)	(611)
Additional Level III information:						
Losses recognized in other comprehensive loss	**(51)**	**—**	**(51)**	(326)	—	(326)
Total gains (losses) included in earnings before income taxes	**(214)**	**36**	**(178)**	37	(491)	(454)
Unrealized gains (losses) included in earnings before income taxes relating to net assets (liabilities) held at period end	**—**	**289**	**289**	—	(409)	(409)

As at Sept. 30, 2023, the total Level III risk management asset balance was $111 million (Dec. 31, 2022 – $31 million) and Level III risk management liability balance was $441 million (Dec. 31, 2022 – $813 million).

The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table. These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

As at		Sept. 30, 2023		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity**
Long-term power sale – US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$40	**+4**
				-30
Coal transportation – US	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$40	**+8**
		Volatility	80% to 120%	
		Rail rate escalation	zero to 10%	**-8**
Full requirements – Eastern US	Scenario analysis	Volume	96% to 104%	**+4**
		Cost of supply	Decrease of $2.20 per MWh or increase of $2.40 per MWh	**-4**
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	**+23**
		Illiquid future REC prices (per unit)	Price decrease of US$3 or increase of US$6	**-23**
		Wind discounts	zero to 5%	
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$65 or increase of C$5	**+49**
		Wind discounts	11% decrease or 5% increase	**-21**
Long-term wind energy sale - Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or increase of US$2	**+88**
		Wind discounts	3% decrease or 2% increase	**-32**
Others				**+14**
				-15

As at		Dec. 31, 2022		
Description	Valuation technique	Unobservable input	Reasonably possible change	Sensitivity
Long-term power sale – US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$55	+15
				-163
Coal transportation – US	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$55	+14
		Volatility	80% to 120%	
		Rail rate escalation	zero to 10%	-13
Full requirements – Eastern US	Scenario analysis	Volume	96% to 104%	+3
		Cost of supply	Decrease of US$0.50 per MWh or increase of US$3.30 per MWh	-21
Long-term wind energy sale – Eastern US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+22
		Illiquid future REC prices (per unit)	Price decrease or increase of US$2	-18
		Wind discounts	0% decrease or 5% increase	
Long-term wind energy sale – Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$85 or increase of C$5	+47
		Wind discounts	28% decrease or 5% increase	-25
Long-term wind energy sale – Central US	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$2	+74
		Wind discounts	2% decrease or 5% increase	-28
Others				+18
				-19

i. Long-Term Power Sale – US
The Company has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

The contract is denominated in US dollars. The US dollar relative to the Canadian dollar did not change significantly from Dec. 31, 2022 to Sept. 30, 2023 and did not have a significant impact on the base fair value or sensitivity values.

ii. 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.

iii. Full Requirements – Eastern US
The Company has a portfolio of full requirement service contracts, whereby the Company agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits ("RECs") and independent system operator costs.

iv. 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.

v. 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 component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue.

vi. 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 customers pay the Company the difference and if the SPP pricing is higher than the fixed contract price the Company refunds the difference to the customers. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commence on commercial operation of the facilities, which is expected during the first quarter of 2024.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 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 revised fixed contract price the customer pays the Company the difference and if the SPP pricing is higher than the revised fixed contract price the Company refunds the difference to the customer. The customer remains entitled to the physical delivery of environmental attributes. During the second quarter of 2023, the Company and the customer for the Horizon Hill wind project amended the associated VPPA. The VPPA commences on commercial operation of the facility, which is expected during the first quarter of 2024.

The energy component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue. The amendments to the Horizon Hill VPPA did not change the nature of the contract and the energy component continues to be accounted for as a derivative.

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 asset fair value of $7 million as at Sept. 30, 2023 (Dec. 31, 2022 – $6 million net liability) 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 I	Level II	Level III	Total	
Exchangeable securities — Sept. 30, 2023	**—**	**690**	**—**	**690**	**743**
Long-term debt — Sept. 30, 2023	**—**	**3,068**	**—**	**3,068**	**3,427**
Loan receivable — Sept. 30, 2023	**—**	**29**	**—**	**29**	**29**
Exchangeable securities — Dec. 31, 2022	—	685	—	685	739
Long-term debt — Dec. 31, 2022	—	3,200	—	3,200	3,518
Loan receivable — Dec. 31, 2022	—	37	—	37	37

(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 10 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. 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:

	9 months ended Sept. 30	
	2023	2022
Unamortized net loss at beginning of period	**(213)**	(131)
New inception gains (losses)	**35**	(40)
Change resulting from amended contract	**28**	—
Change in foreign exchange rates	**1**	(11)
Amortization recorded in net earnings during the period	**(23)**	(21)
Unamortized net loss at end of period	**(172)**	(203)

11. Risk Management Activities

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 2022 audited annual consolidated financial statements.

A. Net Risk Management Assets and Liabilities

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

As at Sept. 30, 2023	**Cash flow hedges**	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**(117)**	**(81)**	**(198)**
Long-term	**(67)**	**(72)**	**(139)**
Net commodity risk management liabilities	**(184)**	**(153)**	**(337)**
Other			
Current	**—**	**6**	**6**
Long-term	**—**	**1**	**1**
Net other risk management assets	**—**	**7**	**7**
Total net risk management liabilities	**(184)**	**(146)**	**(330)**

As at Dec. 31, 2022	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	(271)	(143)	(414)
Long-term	(76)	(96)	(172)
Net commodity risk management liabilities	(347)	(239)	(586)
Other			
Current	—	(6)	(6)
Long-term	—	—	—
Net other risk management liabilities	—	(6)	(6)
Total net risk management liabilities	(347)	(245)	(592)

B. 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.

Value at Risk ("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 Sept. 30, 2023, associated with the Company's proprietary trading activities was $3 million (Dec. 31, 2022 – $4 million).

ii. Commodity Price Risk – Generation

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

VaR at Sept. 30, 2023, associated with the Company's commodity derivative instruments used in generation hedging activities was $27 million (Dec. 31, 2022 – $97 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2023, associated with these transactions was $23 million (Dec. 31, 2022 – $54 million), of which $21 million related to VPPAs (Dec. 31, 2022 – $26 million).

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 Sept. 30, 2023:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[(1)]	85	15	100	**834**
Long-term finance lease receivable	100	—	100	**116**
Risk management assets[(1)]	70	30	100	**227**
Loan receivable[(2)]	—	100	100	**29**
Total				**1,206**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $29 million loan receivable included within other assets with a counterparty that has no external credit rating.

The Company did not have significant expected credit losses as at Sept. 30, 2023.

The Company's maximum exposure to credit risk at Sept. 30, 2023, 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 Sept. 30, 2023, was $24 million (Dec. 31, 2022 – $64 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:

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Accounts payable and accrued liabilities	687	—	—	—	—	—	687
Long-term debt(1)	36	526	141	143	233	2,392	3,471
Exchangeable securities(2)	—	—	—	—	—	750	750
Commodity risk management liabilities	55	151	61	8	13	49	337
Other risk management assets	(3)	(3)	—	—	—	(1)	(7)
Lease liabilities(3)	(11)	3	3	4	4	129	132
Interest on long-term debt and lease liabilities(4)	62	192	172	164	154	858	1,602
Interest on exchangeable securities(2)(4)	13	60	—	—	—	—	73
Dividends payable	15	—	—	—	—	—	15
Total	**854**	**929**	**377**	**319**	**404**	**4,177**	**7,060**

(1) Excludes impact of hedge accounting and derivatives.
(2) Cash payment could occur after Dec. 31, 2028 if exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). At Brookfield's option, the exchangeable securities can be exchanged, at the earliest, on Jan. 1, 2025.
(3) Lease liabilities are net of a lease incentive of $12 million expected to be received in 2023.
(4) Not recognized as a financial liability on the condensed consolidated statements of financial position.

C. Collateral

I. Financial Assets Provided as Collateral

At Sept. 30, 2023, the Company provided $170 million (Dec. 31, 2022 – $304 million) in cash and cash equivalents as collateral to regulated clearing agents and certain utility customers as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. The utility customers are obligated to pay interest on the outstanding balances. Collateral provided is included within trade and other receivables in the condensed consolidated statements of Financial Position.

II. Financial Assets Held as Collateral

At Sept. 30, 2023, the Company held nil (Dec. 31, 2022 – $260 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 Sept. 30, 2023, the Company had posted collateral of $345 million (Dec. 31, 2022 – $820 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 $138 million (Dec. 31, 2022 – $656 million) of collateral to its counterparties.

12. Inventory

The components of inventory are as follows:

As at	Sept. 30, 2023	Dec. 31, 2022
Parts, materials and supplies	**86**	83
Coal	**37**	43
Emission credits	**55**	27
Natural gas	**2**	4
Total	**180**	157

No inventory is pledged as security for liabilities.

As at Sept. 30, 2023, the Company holds 982,862 emission credits in inventory that were purchased externally with a recorded book value of $55 million (Dec. 31, 2022 – 963,068 emission credits with a recorded book value of $27 million). The Company also has 2,885,423 (Dec. 31, 2022 – 3,619,450) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments which have no recorded book value. This includes the eligible emission performance credits earned by the Alberta Hydro facilities formerly under dispute that has now been resolved. Refer to Note 19 for details.

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 June 2023, the Company settled the 2022 carbon compliance obligation in cash. The compliance price of carbon for the 2022 obligation settled was $50 per tonne. It has increased to $65 per tonne in the current year.

13. Investments

Tent Mountain Pumped Hydro Development Project

On April 24, 2023, the Company acquired a 50 per cent interest in the Tent Mountain Renewable Energy Complex (“Tent Mountain”), an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, from Evolve Power Ltd. ("Evolve"), formerly known as Montem Resources Limited. The acquisition included land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company paid Evolve approximately $8 million on closing. Additional contingent payments of up to $17 million may become payable to Evolve based on the achievement of specific development and commercial milestones. The Company and Evolve jointly control Tent Mountain, with the result that the Company accounts for its interest in the joint venture as an investment using the equity method.

14. Property, Plant and Equipment

During the three and nine months ended Sept. 30, 2023, the Company had additions of $146 million and $580 million, respectively, mainly related to the Garden Plain wind facility and assets under construction for the White Rock wind project, the Horizon Hill wind project, the Northern Goldfields solar project, the Mount Keith 132kv transmission expansion and planned major maintenance. The Company also continued its rehabilitation plan for the Kent Hills wind facilities and capitalized additions of $19 million and $61 million, respectively, in the three and nine months ended Sept. 30, 2023.

During the three and nine months ended Sept. 30, 2023, the Company capitalized $15 million and $41 million, respectively (Sept. 30, 2022 — $4 million and $8 million) of interest incurred during construction to property, plant and equipment ("PP&E") at a weighted average rate of 6.3 per cent (Sept. 30, 2022 — 6.0 per cent).

Change in Estimate - Decommissioning Provision

During 2023, the Company adjusted the expected timing on decommissioning and restoration for certain Gas and Energy Transition assets to optimize and maximize efficiencies by staging required reclamation work. This resulted in a decrease in the decommissioning and restoration provision related to operating assets of $15 million and a corresponding decrease in the PP&E carrying value recognized for the nine months ended Sept. 30, 2023. In addition, there were changes in discount rates resulting in an adjustment of $4 million. Refer to Note 15 for further details.

Change in Estimate - Useful Lives

During the third quarter of 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes made based on future operating expectations of the assets. This resulted in a decrease of $46 million in depreciation expense that was recognized in the Condensed Consolidated Statement of Earnings in the third quarter of 2023.

15. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2022	688	41	729
Liabilities incurred	**1**	**4**	**5**
Liabilities settled	**(22)**	**(13)**	**(35)**
Accretion (Note 6)	**37**	**—**	**37**
Revisions in estimated cash flows	**(68)**	**—**	**(68)**
Revisions in discount rates	**(11)**	**—**	**(11)**
Change in foreign exchange rates	**(4)**	**—**	**(4)**
Balance, Sept. 30, 2023	**621**	**32**	**653**

Included in the condensed consolidated statements of financial position as:		
As at	**Sept. 30, 2023**	Dec. 31, 2022
Current portion	**39**	70
Non-current portion	**614**	659
Total Decommissioning and other provisions	**653**	729

A. Decommissioning and Restoration

In the nine months ended Sept. 30, 2023, the decommissioning and restoration provision decreased by $68 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Energy Transition assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E decreased by $15 million and $53 million was recognized as an impairment reversal in net earnings related to retired assets.

For the nine months ended Sept. 30, 2023, revisions in discount rates decreased the decommissioning and restoration provision by $11 million due to an increase in discount rates, largely driven by increases in long-term market benchmark rates. On average, discount rates increased with rates ranging from 7.3 to 10.0 per cent as at Sept. 30, 2023 from 7.0 to 9.7 per cent as at Dec. 31, 2022. This has resulted in a corresponding increase in PP&E of $4 million on operating assets and recognition of a $7 million impairment reversal in net earnings related to retired assets.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions. The onerous contract provisions occurred as a result of decisions to no longer operate on coal in Canada. Payments related to coal contracts for Sheerness are required until 2025. At Sept. 30, 2023, the remaining balance of the provision for the onerous coal contract was $8 million.

16. 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 Sept. 30, 2023		Utilized			
Credit Facilities	Facility size	Outstanding letters of credit(1)	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta Corporation syndicated credit facility	1,250	355	—	895	Q2 2027
TransAlta Renewables syndicated credit facility	700	3	81	616	Q2 2027
TransAlta Corporation bilateral credit facilities	240	171	—	69	Q2 2025
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**529**	**481**	**1,580**	
Non-Committed					
TransAlta Corporation demand facilities	250	88	—	162	N/A
TransAlta Renewables demand facility	150	102	—	48	N/A
Total Non-Committed	**400**	**190**	**—**	**210**	

(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 Sept. 30, 2023, TransAlta provided cash collateral of $170 million.*

These facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business. In June 2023, the TransAlta syndicated credit facility and TransAlta Renewables syndicated credit facility were amended and maturity dates were extended from June 30, 2026 to June 30, 2027. The TransAlta bilateral credit facilities were also amended and maturity dates were extended from June 30, 2024 to June 30, 2025.

On Oct. 5, 2023, upon closing the TransAlta Renewables transaction, as described in Note 22, the syndicated credit facilities were amended to effectively consolidate the TransAlta Renewables syndicated credit facility and non-committed demand facility into the TransAlta credit facilities. The cash drawings on the TransAlta Renewables' syndicated credit facility were repaid and the outstanding letters of credit were transferred to the TransAlta non-committed demand facility. The TransAlta Renewables' credit facilities were then terminated. This resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion.

The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. The $190 million letters of credit are issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities. In addition to the $1.4 billion of committed capacity available under the credit facilities, the Company also had $1.2 billion of available cash and cash equivalents. On Oct. 5, 2023, $800 million of cash was used for the TransAlta Renewables transaction. Refer to the Note 22 for more details.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Sept. 30, 2023, the Company was in compliance with all debt covenants.

B. Repayments

On May 8, 2023, the Pingston Power Inc. non-recourse bond matured with a total aggregate repayment of $46 million, consisting of accrued interest and principal.

C. Issuances

On Sept. 14, 2023, the Company closed a non-recourse bond financing for approximately $39 million ("Pingston bond") as a replacement for the non-recourse bond that matured on May 8, 2023. The Pingston bond is secured by a first ranking charge over all the respective assets of the Company's subsidiaries that issued the bonds, amortizes and bears interest at a rate of 6.145 per cent per annum, payable semi-annually, and matures on May 8, 2043. The Pingston bond is subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facility's operations.

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

The Melancthon Wolfe Wind LP, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds are subject to customary financing conditions and covenants that may restrict the Company’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter of 2023, with the exception of Kent Hills Wind LP and TAPC Holdings LP. Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed and TAPC Holdings LP has been impacted by higher interest rates in 2023. The funds in these entities will remain there until the next debt service coverage ratio is calculated in the fourth quarter of 2023. At Sept. 30, 2023, $74 million (Dec. 31, 2022 – $50 million) of cash was not capable of being distributed due to these financial restrictions. For Kent Hills Wind LP, a foundation replacement reserve account has been set up in accordance with the supplemental indenture, with funds in the account being used to pay foundation replacement costs. The account was funded quarterly with the last planned funding requirement received on March 31, 2023. Subsequent supplemental funding of the account occurs on an as needed basis. The balance in the account is $5 million as at Sept. 30, 2023 (Dec. 31, 2022 – $65 million).

As at Sept. 30, 2023, the Company had $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 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 reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

17. Common Shares

A. Issued and Outstanding

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

	9 months ended Sept. 30			
	2023		2022	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**268.1**	**2,863**	271.0	2,901
Purchased and cancelled under the NCIB(1)	**(6.1)**	**(65)**	(2.7)	(29)
Effects of share-based payment plans	**0.8**	**6**	0.9	6
Stock options exercised	**0.6**	**4**	0.2	1
Issued and outstanding, end of period(2)	**263.4**	**2,808**	269.4	2,879

(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).*

(2) *In October 2023, additional common shares were issued related to the TransAlta Renewables transaction. See Note 22 Subsequent Events for more details.*

On Oct. 5, 2023, the Company issued approximately 46 million shares as partial consideration for its acquisition of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by the Company.

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

On March 27, 2023, the Company entered into an Automatic Share Purchase Plan which permitted an independent broker to repurchase shares under the NCIB during the first quarter blackout period through to May 30, 2023. The number of shares repurchased during the blackout period was 2,943,600.

On May 26, 2023, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement a NCIB for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 Common Shares. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2023 and ends on May 30, 2024.

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

	Sept. 30, 2023	Dec. 31, 2022
Total shares purchased[1]	**6,112,900**	4,342,300
Average purchase price per share	**11.62**	12.48
Total cost (millions)	**71**	54
Book value of shares cancelled	**65**	46
Amount recorded in deficit	**(6)**	(8)

(1) At Dec. 31, 2022, 164,300 shares were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. The Company paid $52 million in 2022 and the remaining amount was paid subsequent to the year end.

C. Dividends

On July 26, 2023, the Company declared a quarterly dividend of $0.055 per common share, payable on Oct. 1, 2023.

On Oct. 27, 2023, the Company declared a quarterly dividend of $0.055 per common share, payable on Jan. 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, except as disclosed in Note 22 Subsequent Events.

18. Preferred Shares

A. Issued and Outstanding

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

	Sept. 30, 2023		Dec. 31, 2022	
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) On Oct. 30, 2020, Brookfield invested $400 million in exchange for redeemable, retractable first preferred shares (Series I). 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 Jul. 26, 2023, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.41545 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.48287 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 Sept. 30, 2023.

On Oct. 27, 2023, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.45288 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.52030 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 Dec. 31, 2023.

19. Commitments and Contingencies

Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in Note 37 of the 2022 audited annual consolidated financial statements, the Company has incurred the following additional contractual commitments in the nine months ended Sept. 30, 2023, either directly or through its interests in joint operations and joint ventures.

Approximate future payments under these agreements are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Transmission	—	2	2	3	4	57	68
Total	**—**	**2**	**2**	**3**	**4**	**57**	**68**

Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed. The table above includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2022 audited annual consolidated financial statements.

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 37 of the 2022 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the *Carbon Competitiveness Incentive Regulation* and *Technology Innovation and Emissions Reduction Regulation* from 2018-2020 inclusive. The EPCs under dispute had no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement and this matter is now resolved.

Brazeau Facility - Well License Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator ("AER") issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometers of the Brazeau Facility but permits hydraulic fracturing in all formations (except the Duvernay) within three-to-five kilometers of the Brazeau Facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licenses (which include hydraulic fracturing activities) within three-to-five kilometers of the Brazeau Facility. The regulatory hearing to consider these applications - Proceeding 379 - is scheduled to be heard from March 18 to March 29, 2024.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometers of the Brazeau Facility pose an unacceptable risk and that the applications should be denied.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within 5 km of the Brazeau Facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (ii) the Alberta Government is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau Facility. On Sept. 29, 2022, the Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the AER, and (ii) is out of time under the *Limitations Act* (Alberta). The trial has been scheduled for two weeks starting Feb. 26, 2024.

Garden Plain

Garden Plain I LP, a wholly owned subsidiary of the Company, retained a third party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction, and significant cost overruns, resulting in overdue deadlines and has asserted a claim for $49 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure.

20. 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 (Loss) before Income Tax

3 months ended Sept. 30, 2023	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	163	62	522	188	86	—	1,021	(4)	—	1,017
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	4	(112)	5	(67)	—	(170)	—	170	—
Realized gain on closed exchange positions	—	—	4	—	8	—	12	—	(12)	—
Decrease in finance lease receivable	—	—	14	—	—	—	14	—	(14)	—
Finance lease income	—	—	2	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	163	66	430	193	26	—	878	(4)	143	1,017
Fuel and purchased power	4	6	111	148	—	—	269	—	—	269
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	6	110	148	—	—	268	—	1	269
Carbon compliance	—	—	28	—	—	—	28	—	—	28
Gross margin	159	60	292	45	26	—	582	(4)	142	720
OM&A	9	20	45	15	13	30	132	(1)	—	131
Taxes, other than income taxes	—	4	3	1	—	—	8	—	—	8
Net other operating income	—	(1)	(10)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA(2)	150	37	254	29	13	(30)	453			
Finance lease income										2
Depreciation and amortization										(140)
Asset impairment reversals										58
Net interest expense										(53)
Foreign exchange loss										(5)
Loss on sale of assets and other										(1)
Earnings before income taxes										453

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

3 months ended Sept. 30, 2022	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	265	14	372	231	54	(4)	932	(3)	—	929
Reclassifications and adjustments:										
Unrealized mark-to-market loss	—	53	47	6	46	—	152	—	(152)	—
Realized loss on closed exchange positions	—	—	(4)	—	(38)	—	(42)	—	42	—
Decrease in finance lease receivable	—	—	12	—	—	—	12	—	(12)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	265	67	431	237	62	(4)	1,058	(3)	(126)	929
Fuel and purchased power	7	6	167	167	—	1	348	—	—	348
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	7	6	166	167	—	1	347	—	1	348
Carbon compliance	—	—	26	2	—	(5)	23	—	—	23
Gross margin	258	61	239	68	62	—	688	(3)	(127)	558
OM&A	12	19	49	17	9	30	136	(1)	—	135
Taxes, other than income taxes	1	1	5	—	—	1	8	—	—	8
Net other operating income	—	(1)	(10)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA[2]	245	42	195	51	53	(31)	555			
Equity income										1
Finance lease income										4
Depreciation and amortization										(179)
Asset impairment charges										(70)
Net interest expense										(66)
Foreign exchange gain										6
Gain on sale of assets and other										4
Loss before income taxes										126

(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 have no standardized meaning under IFRS.

9 months ended Sept. 30, 2023	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	456	263	1,268	576	181	1	2,745	(14)	—	2,731
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(2)	(4)	(120)	(12)	42	—	(96)	—	96	—
Realized loss on closed exchange positions	—	—	(13)	—	(95)	—	(108)	—	108	—
Decrease in finance lease receivable	—	—	40	—	—	—	40	—	(40)	—
Finance lease income	—	—	10	—	—	—	10	—	(10)	—
Adjusted revenues	454	259	1,185	564	128	1	2,591	(14)	154	2,731
Fuel and purchased power	14	22	326	419	—	1	782	—	—	782
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	14	22	323	419	—	1	779	—	3	782
Carbon compliance	—	—	85	—	—	—	85	—	—	85
Gross margin	440	237	777	145	128	—	1,727	(14)	151	1,864
OM&A	35	55	136	46	33	86	391	(2)	—	389
Taxes, other than income taxes	2	11	11	3	—	—	27	(1)	—	26
Net other operating income	—	(4)	(30)	—	—	—	(34)	—	—	(34)
Adjusted EBITDA[2]	403	175	660	96	95	(86)	1,343			
Equity income										1
Finance lease income										10
Depreciation and amortization										(489)
Asset impairment reversals										74
Net interest expense										(168)
Gain on sale of assets and other										4
Earnings before income taxes										915

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

9 months ended Sept. 30, 2022	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	447	205	933	433	116	(2)	2,132	(10)	—	2,122
Reclassifications and adjustments:										
Unrealized mark-to-market loss	—	81	13	17	—	—	111	—	(111)	—
Realized gain (loss) on closed exchange positions	—	—	(11)	—	27	—	16	—	(16)	—
Decrease in finance lease receivable	—	—	34	—	—	—	34	—	(34)	—
Finance lease income	—	—	15	—	—	—	15	—	(15)	—
Adjusted revenues	447	286	984	450	143	(2)	2,308	(10)	(176)	2,122
Fuel and purchased power	17	20	445	332	—	3	817	—	—	817
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	17	20	442	332	—	3	814	—	3	817
Carbon compliance	—	1	56	(1)	—	(5)	51	—	—	51
Gross margin	430	265	486	119	143	—	1,443	(10)	(179)	1,254
OM&A	33	50	138	50	23	71	365	(1)	—	364
Taxes, other than income taxes	3	7	13	2	—	1	26	(1)	—	25
Net other operating income	—	(18)	(30)	—	—	—	(48)	—	—	(48)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(11)	(30)	—	—	—	(41)	—	(7)	(48)
Adjusted EBITDA(2)	394	219	365	67	120	(72)	1,093			
Equity income										5
Finance lease income										15
Depreciation and amortization										(411)
Asset impairment charges										(4)
Net interest expense										(195)
Foreign exchange gain										17
Gain on sale of assets and other										6
Earnings before income taxes										346

(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.

21. 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. 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 related parties that have been measured at exchange value and recognized in the consolidated financial statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate. Refer to Note 26 and 36 of the 2022 audited annual consolidated financial statements.

Transactions with Brookfield include the following:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2023	2022	**2023**	2022
Power sales	**37**	45	**111**	86

22. Subsequent Events

TransAlta to Acquire Heartland Generation

On Nov. 2, 2023, the Company announced that it has entered into a definitive share purchase agreement (the "Agreement") with an affiliate of Energy Capital Partners, the parent of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, "Heartland"), pursuant to which TransAlta will acquire Heartland and its entire business operations in Alberta and British Columbia. The purchase price for the acquisition is $390 million, subject to working capital and other adjustments, as well as the assumption of $268 million of low-cost debt, for a total cost of $658 million. The Company will finance the transaction using cash on hand and draws on its credit facilities. The closing of the transaction remains subject to regulatory approval which is expected to be obtained in the first half of 2024.

TransAlta Corporation Acquires TransAlta Renewables Inc.

On Oct. 5, 2023, the Company announced the completion of the previously announced acquisition of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by the Company. The consideration paid totaled $1.3 billion, comprising $800 million of cash and approximately 46 million common shares of the Company valued at $514 million, based on an $11.06 closing price of the Company's shares on the Toronto Stock Exchange on Oct. 4, 2023. Since the Company retained control of TransAlta Renewables, the acquisition will be accounted for as an equity transaction. The consideration paid reduced Cash and Cash Equivalents by $800 million and increased Common Shares by $514 million, with the additional impact being a reallocation of amounts from Non-controlling Interests to Equity Attributable to Shareholders. Transaction costs of $10 million incurred to effect the acquisition, recognized as Prepaid Expenses as at Sept. 30, 2023, will be reclassified against Common Shares and Deficit on closing of the acquisition in the fourth quarter of 2023.

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.

Balancing Pool

The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Its current obligations and responsibilities are governed by the *Electric Utilities Act* (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

Capacity

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

Cogeneration

A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

Derate

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

Disclosure Controls and Procedures (DC&P)

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

Dispatch optimization

Purchasing power to fulfill contractual obligations, when economical.

Emissions Performance Standards (EPS)

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

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.

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

Phone
403.267.7110

Website
www.transalta.com

Transfer Agent
Computershare Trust Company of Canada
Suite 600, 530 - 8th Avenue SW
Calgary, Alberta T2P 3S8

Phone
Toll-free in North America: 1.800.564.6253
Outside North America: 514.982.7555

Website
www.computershare.com

FOR MORE INFORMATION

Investor Inquiries

Phone
Toll-free in North America: 1.800.387.3598
Calgary or Outside North America: 403.267.2520

E-mail
investor_relations@transalta.com

Media Inquiries

Phone
Toll-free 1.855.255.9184
or 403.267.2540

E-mail
TA_Media_Relations@transalta.com