TRANSALTA CORPORATION
Management's Discussion and Analysis

Third Quarter Report for 2022

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

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This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2022 and 2021, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A ("2021 Annual MD&A") contained within our 2021 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, 2022. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Nov. 7, 2022. Additional information respecting TransAlta, including our Annual Information Form ("AIF") for the year ended Dec. 31, 2021, is available on SEDAR at **www.sedar.com**, 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 US 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: our Clean Electricity Growth Plan and ability to achieve the target of 2 gigawatts ("GW") of incremental renewables capacity with an estimated capital investment of $3 billion that is expected to deliver incremental average annual EBITDA of $250 million; the Company's projects under construction, including the timing of commercial operations, expected annual EBITDA and associated costs, including the Horizon Hill wind project ("Horizon Hill wind project"), the White Rock East and White Rock West wind power projects ("White Rock wind projects"), Northern Goldfields solar project, Garden Plain wind project and the Mount Keith 132kV transmission expansion; the execution of the Company's early and advanced stage development pipeline, including the size, cost and expected EBITDA from such projects; the expansion of the Company's early stage development pipeline to 5 GW; the proportion of EBITDA to be generated from renewable sources by the end of 2025; the 2022 Financial Outlook (defined below), including adjusted EBITDA and free cash flow; the Company's ability to enhance shareholder value through its NCIB (as defined below); the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the remediation of the Kent Hills 1 and 2 wind facilities, including, the timing and cost of such remediation, the resulting impact of such remediation on the Company's revenues and the potential battery storage project at and repowering of, the Kent Hills facilities; the expected impact and quantum of carbon compliance costs; the ability to realize future growth opportunities with BHP (as defined below); regulatory developments and their expected impact on the Company, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing and increased funding for clean technology), the proposed new Clean Electricity Regulation, the Clean Fuel Regulations and Canadian Greenhouse Gas Offset Credit System Regulations and the ability of the Company to realize benefits from Canadian, United States and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; sustaining and productivity capital in 2022; expected power prices in Alberta, Ontario and the Pacific Northwest; AECO gas price assumptions; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; and the Company continuing to maintain a strong financial position and significant liquidity without any significant impact from the current economic environment.

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 the long-term investment and credit markets; no significant changes to power price and hedging assumptions including, Alberta spot prices of $125/MWh to $150/MWh in 2022 and Mid-Columbia spot prices of US$55/MWh to US$65/MWh in 2022; AECO gas prices of between $5.00/GJ and $6.00/GJ; sustaining capital of $145 million to $155 million; Energy Marketing adjusted gross margin of $145 to $160 million; no significant changes to gas commodity prices and transport costs; the Company's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; and the impacts arising from COVID-19 not becoming significantly more onerous on the Company.

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: increased force majeure claims; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment; our ability to obtain regulatory and any other third party approvals on the expected timelines or at all in respect of our growth projects; risks associated with development and construction projects, including as it pertains to increased capital costs, permitting, labour and engineering risks and potential delays in the construction or commissioning of such projects; restricted access to capital and increased borrowing costs; changes in short-term and long-term electricity supply and demand; fluctuations in market prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; a higher rate of losses on our accounts receivable; impairments and/or write-downs of assets; adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats; commodity risk management and energy trading risks, including the effectiveness of the Company's risk management tools associated with hedging and trading procedures to protect against significant losses; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and 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, 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 remediation and replacement of turbine foundations of the Kent Hills 1 and 2 wind facilities; general economic risks, 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 associated impacts; the threat of terrorism; adverse diplomatic developments or other similar events that could adversely affect our business; industry risk and competition; fluctuations in the value of foreign currencies; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; our provision for income taxes and any risk of reassessment; legal, regulatory and contractual disputes and proceedings involving the Company; reliance on key personnel; labour relations matters; and the impact of COVID-19. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our 2021 Annual MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2021.

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 111 years of operating experience. We own, operate and manage a geographically diversified portfolio of assets utilizing a broad range of fuels that includes water, wind, solar, natural gas and battery storage.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as at Sept. 30, 2022:

As at Sept. 30, 2022		Hydro	Wind and Solar	Gas(5)	Energy Transition(6)	Total
Alberta	Gross installed capacity (MW)(1)	834	636	1,960	—	**3,430**
	Number of facilities	17	13	7	—	**37**
	Weighted average contract life(2)(3)(4)	—	6	1	—	**2**
Canada, Excl. Alberta	Gross installed capacity (MW)(1)	91	751	645	—	**1,487**
	Number of facilities	9	9	3	—	**21**
	Weighted average contract life(3)	6	12	10	—	**9**
United States	Gross installed capacity (MW)(1)	—	519	29	671	**1,219**
	Number of facilities	—	7	1	2	**10**
	Weighted average contract life(3)	—	11	3	3	**7**
Australia	Gross installed capacity (MW)(1)	—	—	450	—	**450**
	Number of facilities	—	—	6	—	**6**
	Weighted average contract life(3)	—	—	16	—	**16**
Total	**Gross installed capacity (MW)(1)**	**925**	**1,906**	**3,084**	**671**	**6,586**
	Number of facilities	**26**	**29**	**17**	**2**	**74**
	Weighted average contract life(3)	**1**	**10**	**5**	**3**	**6**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for Wind and Solar includes 100 per cent of the Kent Hills wind facilities; Gas 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 for more information.
(3) For power generated under long-term power purchase agreements ("PPA"), 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 McBride Lake (38 MW), Windrise Wind (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.
(5) The Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal-fired generation assets converted to gas from the segment previously known as Alberta Thermal.
(6) The Energy Transition segment includes Centralia Unit 2 and the Skookumchuck dam.

The Company has retired all coal-fired generating assets located in Alberta within the Energy Transition segment. Effective Dec. 31, 2021, Keephills Unit 1 was retired and Sundance Unit 4 was retired from service effective March 31, 2022, resulting in a reduction in capacity of 801 MW within the Energy Transition segment from Dec. 31, 2021.

Highlights

Unaudited Interim Condensed Consolidated Financial Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Adjusted availability (%)	**93.8**	89.2	**90.1**	87.5
Production (GWh)	**5,432**	6,053	**15,253**	16,282
Revenues	**929**	850	**2,122**	2,111
Fuel and purchased power(1)	**348**	328	**817**	788
Carbon compliance	**23**	47	**51**	139
Operations, maintenance and administration(1)	**135**	130	**364**	381
Adjusted EBITDA(2)	**555**	402	**1,093**	1,043
Earnings (loss) before income taxes	**126**	(441)	**346**	(348)
Net earnings (loss) attributable to common shareholders	**61**	(456)	**167**	(498)
Cash flow from operating activities	**204**	610	**526**	947
Funds from operations(2)	**488**	318	**887**	808
Free cash flow(2)	**393**	210	**646**	506
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.23**	(1.68)	**0.62**	(1.84)
Dividends declared per common share(3)	**0.050**	0.045	**0.100**	0.090
Dividends declared per preferred share(3)	**0.2896**	0.2484	**0.5453**	0.5075
Funds from operations per share(2)(4)	**1.80**	1.17	**3.27**	2.98
Free cash flow per share(2)(4)	**1.45**	0.77	**2.38**	1.87

As at	**Sept. 30, 2022**	Dec. 31, 2021
Total assets	**10,045**	9,226
Total consolidated net debt(5)	**2,700**	2,636
Total long-term liabilities	**4,668**	4,702
Total liabilities	**7,628**	6,633

(1) During the three and nine months ended Sept. 30, 2021, $1 million and $6 million, respectively, related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(2) 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. Please 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. Please see also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) Weighted average of the Series A, B, C, D, E and G preferred share dividends declared. Dividends declared vary period over period due to the timing of dividend declarations and quarterly floating rates.
(4) 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, 2022, was 271 million shares (Sept. 30, 2021 - 271 million for both periods). Please refer to the Additional IFRS Measures and Non-IFRS Measures section in this MD&A for the purpose of these non-IFRS ratios.
(5) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, 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. Please refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

For the three and nine months ended Sept. 30, 2022, we have generated exceptional performance from our Alberta Electricity Portfolio, driving overall strong performance for the Company. Both the Hydro and the Gas segments had high availability during periods of peak pricing. Higher power prices were mainly due to above normal temperatures increasing the demand for electricity, higher power prices in adjacent markets reducing electricity imports, and periods of significant planned and unplanned thermal and transmission outages. The Alberta merchant portfolio was positioned to capture opportunities from the strong spot market conditions through both energy and ancillary services revenues. Subsequent to the third quarter, we revised and increased our guidance for adjusted EBITDA and FCF based on the strong financial performance attained to date and our expectations for the balance of year. Please refer to the 2022 Financial Outlook section of this MD&A for more details on our updated guidance.

Adjusted availability for the three and nine months ended Sept. 30, 2022, was 93.8 per cent and 90.1 per cent, respectively, compared to 89.2 per cent and 87.5 per cent for the same periods in 2021. The increase was primarily due to lower planned outages within the Gas segment with the completion of the coal-to-gas conversions in 2021, and lower planned and unplanned outages at our Alberta Hydro Assets, partially offset by the extended outage at the Kent Hills 1 and 2 wind facilities. In addition, adjusted availability for the nine months ended Sept. 30, 2022, was further offset by the early-stage operational issues associated with the commissioning of the Windrise wind facility in the Wind and Solar segment.

Production for the three and nine months ended Sept. 30, 2022, was 5,432 gigawatt hours ("GWh") and 15,253 gigawatt hours, respectively, compared to 6,053 GWh and 16,282 GWh in the same periods in 2021. The decrease in production was primarily due to the retirement of Keephills Unit 1 and Sundance Unit 4, portfolio optimization activities and the extended outage at the Kent Hills 1 and 2 wind facilities. This was partially offset by an increase in production from the addition of the Windrise wind facility commissioned in the fourth quarter of 2021 and North Carolina Solar facility acquired in the fourth quarter of 2021 in our Wind and Solar segment. Production for the three months ended Sept. 30, 2022, was also impacted by higher water resources and lower wind resources across North America driven by higher than average temperatures. Production for the nine months ended Sept. 30, 2022, was impacted by higher water resources and lower availability at the Windrise wind facility.

Revenues increased by $79 million and $11 million, respectively, for the three and nine months ended Sept. 30, 2022, compared to the same periods in 2021, mainly as a result of capturing higher realized energy prices within the Alberta electricity market through our optimization and operating activities and higher realized ancillary services prices and volumes in the Hydro segment. Revenues also increased due to higher merchant prices at Centralia partially offset by lower production. In addition, revenues during the third quarter of 2022, were partially offset by lower environmental credit sales. During the second quarter of 2021, the Company experienced unfavourable adjustments for unplanned steam supply outages and steam reconciliation adjustments that did not reoccur within the current period within the Gas segment.

Fuel and purchased power costs increased by $20 million and $29 million, respectively, for the three and nine months ended Sept. 30, 2022, compared to the same periods in 2021. Fuel and purchased power costs increased compared to 2021 due to higher natural gas prices and increased natural gas consumption for our converted units in 2022, partially offset by our hedged positions on gas, lower coal costs and no mine depreciation due to the termination of all coal-mining activities in Canada as of Dec. 31, 2021.

Carbon compliance costs decreased by $24 million and $88 million, respectively, for the three and nine months ended Sept. 30, 2022, compared to the same periods in 2021, primarily due to reductions in greenhouse gas ("GHG") emissions, lower production and utilization of our compliance credits to settle a portion of the GHG obligation, partially offset by an increase in the carbon price per tonne. Lower GHG emissions were a direct result of operating exclusively on natural gas in Alberta rather than coal, resulting in changes in the fuel mix ratio.

Operations, maintenance and administration ("OM&A") expenses increased by $5 million for the three months ended Sept. 30, 2022, compared to the same period in 2021. For the three months ended Sept. 30, 2021, the Company recorded a write-down of $5 million on parts and material inventory related to the Highvale mine and coal operations at our converted gas facilities. Excluding the impact of this write-down, OM&A increased by $10 million in 2022, mainly due to higher contractor costs, higher incentive accruals reflecting the Company's performance, OM&A related to the addition of the Windrise wind and North Carolina Solar facilities and higher general operating expenses.

For the nine months ended Sept. 30, 2022, OM&A decreased by $17 million. For the nine months ended Sept. 30, 2021, the Company recorded a write-down of $30 million on parts and material inventory related to the retirement of the Highvale mine and coal operations at our converted gas facilities. In addition, during the first quarter of 2021, the Company recognized the Canada Emergency Wage Subsidy ("CEWS") proceeds of $8 million. Excluding the impact of the write-downs and the CEWS funding, OM&A expenses were higher by $5 million in 2022, mainly due to higher contractor costs, higher incentive accruals reflecting Company's performance, OM&A related to the addition of the Windrise wind and North Carolina Solar facilities and higher general operating expenses.

Adjusted EBITDA increased by $153 million for the three months ended Sept. 30, 2022, compared to the same period in 2021, largely due to strong performance from our Alberta Electricity Portfolio, driven primarily by the Hydro and Gas segments as a result of strong weather-adjusted demand and higher power prices. This was partially offset by lower adjusted EBITDA from the retirement of units in the Energy Transition segment, lower production and lower revenues in the Wind and Solar segment, lower gross margin in Energy Marketing and higher corporate expenses.

Adjusted EBITDA increased by $50 million for the nine months ended Sept. 30, 2022, compared to the same period in 2021, largely due to higher adjusted EBITDA from higher production and merchant power pricing in the Hydro segment, continuing strong performance and contribution from the Gas segment for Alberta, incremental production from new facilities, liquidated damages related to turbine availability at the Windrise wind facility, higher environmental credit sales in the Wind and Solar segment and lower carbon compliance costs in both the Gas and Energy Transition segments. This was partially offset from lower production from the Gas and Energy Transition segments, higher fuel and purchased power costs within the Gas segment. On a year-to-date basis, the Energy Marketing segment results were lower but in line with expectations compared with the exceptional results in the prior period. Significant changes in segmented adjusted EBITDA are highlighted in the Segmented Financial Performance and Operating Results section of this MD&A.

Earnings (loss) before income taxes increased by $567 million and $694 million, respectively, for the three and nine months ended Sept. 30, 2022, compared to the same periods in 2021. **Net earnings attributable to common shareholders** for the three and nine months ended Sept. 30, 2022, increased by $517 million and $665 million, respectively, to net earnings of $61 million and $167 million, respectively, compared to a net loss of $456 million and $498 million, respectively, for the same period in 2021. Net earnings attributable to common shareholders in 2021 were significantly impacted by asset impairment charges resulting from the Company's decisions to shut down the Highvale mine, suspend the Sundance Unit 5 repowering project, and retire Sundance Unit 4 and Keephills Unit 1. The Company benefited from higher revenues and lower carbon compliance costs, partially offset by higher fuel and purchased power, higher depreciation due to the acceleration of useful lives on certain facilities and higher tax expense. In addition, during the nine months ended Sept. 30, 2022, the Company recognized liquidated damages payable to the Company related to turbine availability at the Windrise wind facility and insurance proceeds related to the replacement costs for a tower at the Kent Hills facility. During the nine months ended Sept. 30, 2021, the Company recognized a gain on the sale of the Pioneer Pipeline.

Cash flow from operating activities decreased by $406 million and $421 million, respectively, for the three and nine months ended Sept. 30, 2022, compared to the same periods in 2021, mainly due to unfavourable changes in working capital from higher accounts receivable and movements in the collateral accounts related to high commodity prices and volatility in the markets.

FCF, one of the Company's key financial metrics, for the three and nine months ended Sept. 30, 2022, totaled $393 million and $646 million, respectively, compared to $210 million and $506 million, respectively, for the same periods in 2021. This represents an increase to FCF of $183 million and $140 million, respectively, driven primarily by higher adjusted EBITDA, higher realized foreign exchange gains, lower current income tax expenses and a decrease in sustaining capital spending related to fewer planned maintenance turnarounds.

Significant and Subsequent Events

Changes to the Board of Directors

On Sept. 30, 2022, Ms. Beverlee Park retired from TransAlta's Board of Directors. Ms. Park served on the Board of Directors since 2015 and as Chair of the Audit, Finance and Risk Committee from April 2018 to April 2022. The Company recognizes her for the many contributions made by Ms. Park to TransAlta and thanks her for the many years of service.

New Term Facility

During the third quarter of 2022, the Company closed a two year $400 million floating rate Term Facility with its banking syndicate with a maturity date of Sept. 7, 2024.

Conversion Results for Series E and F Preferred Shares

On Sept. 21, 2022, there were 89,945 Cumulative Redeemable Rate Reset First Preferred Shares, Series E ("Series E Shares") tendered for conversion, which was less than the one million shares required to give effect to conversions into Cumulative Redeemable Rate Reset First Preferred Shares, Series F ("Series F Shares"). As a result, the Series E Shares were not converted into Series F Shares.

Executed Contract Renewals with the IESO at Sarnia Cogeneration and Melancthon 1 Wind Facilities

On Aug. 23, 2022, TransAlta Renewables Inc., a subsidiary of the Company ("TransAlta Renewables") announced that it was awarded capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility from the Ontario Independent Electricity System Operator ("IESO") as part of the IESO's Medium-Term Capacity Procurement Request For Proposals (the "RFP"). The new capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility run from May 1, 2026 to April 30, 2031. The Company expects the gross margin from the Sarnia cogeneration facility to be reduced by approximately 30 per cent per year as a result of the IESO price cap under the new contract.

Sarnia Industrial Contract Extensions

During the second quarter of 2022, the Company executed contract extensions for the supply of electricity with three industrial customers, and steam with one of these customers, at the Sarnia cogeneration facility. These agreements will extend the delivery term from Dec. 31, 2022 to April 30, 2031, in one case, and to Dec. 31, 2032, for the other two.

TransAlta Debuts New Brand Reiterating Commitment to a Clean Energy Future

On June 20, 2022, the Company announced a new visual identity including logo and tagline, "Energizing the Future". The new visual identity encapsulates the TransAlta of today while reinforcing the Company's focus as a leader in creating a carbon-neutral future for our customers.

Conversion Results for Series C and D Preferred Shares

On June 16, 2022, the Company announced that 1,044,299 of its 11,000,000 currently outstanding Cumulative Redeemable Rate Reset First Preferred Shares, Series C ("Series C Shares") were tendered for conversion, on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D ("Series D Shares") after having taken into account all election notices.

Court of Appeal Upholds TransAlta's Favourable Force Majeure Arbitration Decision

On June 9, 2022, the Alberta Court of Appeal released a unanimous decision dismissing ENMAX Energy Corporation's ("ENMAX") and the Balancing Pool's application seeking to set aside an arbitration decision in favour of the Company. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills Unit 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta.

Keephills Unit 2 Stator Force Majeure Dispute Settled

After the Keephills Unit 1 stator force majeure outage in 2013, it was determined that Keephills Unit 2 could face a similar stator failure before the next planned outage. In response, the Company took Keephills Unit 2 offline between January 31, 2014 and March 15, 2014 to perform a full rewind of the generator stator and claimed force majeure. The Balancing Pool disputed this force majeure event but the dispute was held in abeyance pending the outcome of the Keephills Unit 1 stator force majeure dispute, which was recently concluded. The Company and the Balancing Pool recently settled this dispute and so both stator Force majeure claims have been resolved.

Kent Hills Wind Facilities Update

On June 2, 2022, TransAlta Renewables announced the rehabilitation plan for the Kent Hills 1 and 2 wind facilities together with the execution of amended and extended contracts with New Brunswick Power Corporation ("NB Power") in respect of each of the Kent Hills 1, 2 and 3 wind facilities providing for an additional 10-year contract term to December 2045 and an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033. In addition, both parties have agreed to work in good faith to evaluate the installation of a battery energy storage system at Kent Hills and to consider a potential repowering of Kent Hills at the end of life in 2045. A waiver for the Kent Hills wind non-recourse bonds ("KH Bonds") was also obtained from the project bond holders and a supplemental indenture was entered into with the bond holders that facilitates the rehabilitation of the Kent Hills 1 and 2 wind facilities. Refer to the Wind and Solar section and Financial Capital section of this MD&A for further details.

TSX Acceptance of Normal Course Issuer Bid

On May 24, 2022, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to renew its 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 7.16 per cent of its public float of common shares as at May 17, 2022. 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, 2022 and ends on May 30, 2023, 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 does not reflect their underlying value and purchases of common shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

During the nine months ended Sept. 30, 2022, the Company purchased and cancelled a total of 2.7 million common shares at an average price of $12.50 per common share, for a total cost of $34 million.

Mount Keith 132kV Transmission Expansion

On May 3, 2022, TransAlta Renewables exercised its option to acquire an economic interest in the expansion of the Mount Keith 132kV transmission system in Western Australia, to support the Northern Goldfields-based operations of BHP Nickel West ("BHP"). Total construction capital is estimated at between AU$50 million and AU$53 million. Southern Cross Energy, a subsidiary of the Company, has entered into an engineering, procurement and construction agreement for the expansion. The project is being developed under the existing PPA with BHP, which has a term of 15 years. It is expected to be completed in the second half of 2023 and will generate annual adjusted EBITDA in the range of AU$6 million and AU$7 million. The project will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase its competitiveness as a supplier of low-carbon nickel.

Executed Long-term PPA for the Remaining 30 MW at Garden Plain

During the second quarter of 2022, the Company entered into a long-term PPA for the remaining 30 MW of renewable electricity and environmental attributes for the Garden Plain wind project in Alberta with a new investment-grade globally-recognized customer. The 130 MW Garden Plain wind project, which was announced in May 2021 with a 100 MW PPA contracted to Pembina Pipeline Corporation ("Pembina"), is now fully contracted with a weighted average contract life of approximately 17 years. Construction is underway with a target commercial operation date in the fourth quarter of 2022.

Energy Impact Partners ("EIP") Investment

During the second quarter of 2022, the Company entered into a commitment to invest US$25 million over the next four years in EIP's Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). The Company invested US$6 million in May 2022. The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions.

Customer Update at White Rock Wind Projects

During the second quarter of 2022, TransAlta identified Amazon Energy LLC ("Amazon") as the customer for the 300 MW White Rock wind projects, to be located in Caddo County, Oklahoma. On Dec. 22, 2021, Amazon and TransAlta entered into two long-term PPAs for the supply of 100 per cent of the generation from the projects. Construction activities started in the fall of 2022 with a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facility.

MSCI Environmental, Social and Governance ("ESG") Rating Upgrade

During the second quarter of 2022, TransAlta's MSCI ESG Rating was upgraded to 'A' from 'BBB'. The upgrade reflects the Company's strong renewable energy growth compared to peers. In 2021, the Company grew its installed renewable energy capacity by 15 per cent through the acquisition and construction of solar and wind facilities and secured 600 MW in additional renewable energy projects. In line with its goal to reduce carbon emissions by 75 per cent from 2015 emissions levels by 2026, TransAlta also completed coal-to-gas conversions of its Canadian coal-fired facilities in 2021, nine years ahead of Alberta's coal phase-out plan.

Horizon Hill Wind Project and Fully Executed Corporate PPA with Meta

On April 5, 2022, TransAlta executed a long-term renewable energy PPA with a subsidiary of Meta Platforms Inc. ("Meta"), formerly known as Facebook, Inc., for 100 per cent of the generation from its 200 MW Horizon Hill wind project to be located in Logan County, Oklahoma. Under this agreement, Meta will receive both renewable electricity and environmental attributes from the Horizon Hill facility. The facility will consist of a total of 34 Vestas turbines. Construction commenced in the fall of 2022 with a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facility.

Refer to the audited annual 2021 consolidated financial statements within our 2021 Annual Integrated Report and our unaudited interim condensed consolidated financial statements for the three and nine months ended Sept. 30, 2022, for significant events impacting both prior and current year results.

Performance by Segment with Supplemental Geographical Information

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

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

3 months ended Sept. 30, 2021	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate and Other	Total
Alberta	78	21	94	18	79	(24)	266
Canada, excluding Alberta	4	21	22	—	—	—	47
United States	—	13	3	37	—	—	53
Australia	—	—	36	—	—	—	36
Adjusted EBITDA[(3)]	82	55	155	55	79	(24)	402
Loss before income taxes							(441)

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

9 months ended Sept. 30, 2021	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate and Other	Total
Alberta	245	41	227	33	177	(56)	667
Canada, excluding Alberta	10	92	51	—	—	—	153
United States	—	53	8	63	—	—	124
Australia	—	—	99	—	—	—	99
Adjusted EBITDA[(3)]	255	186	385	96	177	(56)	1,043
Loss before income taxes							(348)

(1) The Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal-fired generation assets converted to gas from the segment previously known as Alberta Thermal.
(2) The Energy Transition segment includes the segment previously known as Centralia and the coal-fired generation assets not converted to gas and the mining assets from the segment previously known as Alberta Thermal. Keephills Unit 1 was retired Dec. 31, 2021 and Sundance Unit 4 was retired March 31, 2022.
(3) 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. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Alberta Electricity Portfolio

Approximately 52 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, cogeneration facilities 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 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.

Generating energy in Alberta is subject to market forces, rather than rate regulation. Energy from commercial generation is cleared through a wholesale electricity market. Energy is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator ("AESO"), based upon offers by generators to sell energy in the real-time energy-only market. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell energy.

	2022					2021				
3 months ended Sept. 30	**Hydro**	**Wind and Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind and Solar	Gas	Energy Transition	Total
Total Production (GWh)[1]	**614**	**259**	**1,993**	**—**	**2,866**	513	259	2,025	600	3,397
Contract Production (GWh)	**4**	**111**	**127**	**—**	**242**	—	55	117	—	172
Merchant Production (GWh)	**610**	**148**	**1,866**	**—**	**2,624**	513	204	1,908	600	3,225
Revenues[2]	**256**	**25**	**290**	**(2)**	**569**	90	29	205	59	383
Fuel and purchased power[3]	**6**	**3**	**110**	**—**	**119**	3	2	68	17	90
Carbon compliance	**—**	**1**	**23**	**2**	**26**	—	—	27	15	42
Gross margin	**250**	**21**	**157**	**(4)**	**424**	87	27	110	27	251

	2022					2021				
9 months ended Sept. 30	**Hydro**	**Wind and Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind and Solar	Gas	Energy Transition	Total
Total Production (GWh)[1]	**1,356**	**1,211**	**5,537**	**19**	**8,123**	1,263	819	5,953	1,416	9,451
Contract Production (GWh)	**4**	**433**	**385**	**—**	**822**	—	108	367	—	475
Merchant Production (GWh)	**1,352**	**778**	**5,152**	**19**	**7,301**	1,263	711	5,586	1,416	8,976
Revenues[2]	**426**	**109**	**588**	**5**	**1,128**	282	64	544	149	1,039
Fuel and purchased power[3]	**14**	**12**	**294**	**5**	**325**	5	5	187	48	245
Carbon compliance	**—**	**1**	**47**	**(1)**	**47**	—	—	87	35	122
Gross margin	**412**	**96**	**247**	**1**	**756**	277	59	270	66	672

(1) Units in the Gas and Energy Transition segments in the prior periods operated on coal. Keephills Unit 1 was retired Dec. 31, 2021, and Sundance Unit 4 was retired March 31, 2022.
(2) Adjustments to revenues include the impact of unrealized mark-to-market gains or losses and realized gains and losses on closed exchange positions.
(3) Adjustments to fuel and purchased power include the impact of coal mine depreciation and coal inventory write-downs at the Highvale mine in 2021.

For the three and nine months ended Sept. 30, 2022, the Alberta Electricity Portfolio generated 2,866 GWh and 8,123 GWh of energy, respectively, a decrease of 531 GWh and 1,328 GWh, respectively, compared to the same periods in 2021. Production was impacted by the retirement of Keephills Unit 1 on Dec. 31, 2021, and Sundance Unit 4 on March 31, 2022, dispatch optimization, lower wind resources impacted the three-month period, partially offset by increased production from the addition of the Windrise wind facility commissioned in the fourth quarter of 2021. Production in the three months ended Sept. 30, 2022, benefited from higher water resources from a delayed spring runoff.

Gross margin for the three and nine months ended Sept. 30, 2022, was $424 million and $756 million, respectively, an increase of $173 million and $84 million, respectively, compared to the same periods in 2021. Gross margin for the three months ended Sept. 30, 2022, was positively impacted by higher merchant pricing resulting from strong weather-driven demand, higher natural gas prices and higher power prices in adjacent markets compared to 2021. Energy and ancillary services revenue from the Hydro segment was higher as a result of higher power prices and market volatility. Gross margin for the nine months ended Sept. 30, 2022, was positively impacted by strong weather-driven demand, partially offset by a better-supplied market. The Gas and Energy Transition segment results were impacted by lower production due to unit retirements and higher dispatch optimization in response to lower market heat rates and higher gas prices.

The following table provides information about the Company's Alberta Electricity Portfolio:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Spot power price average per MWh	**$221**	$100	**$145**	$100
Natural gas price (AECO) per GJ	**$4.04**	$3.29	**$5.14**	$3.04
Carbon compliance price per tonne	**$50**	$40	**$50**	$40
Realized merchant power price per MWh(1)	**$253**	$113	**$164**	$112
Hydro energy spot power price per MWh	**$246**	$110	**$177**	$116
Hydro ancillary spot price per MWh	**$128**	$47	**$74**	$58
Wind energy spot power price per MWh	**$136**	$73	**$86**	$58
Gas and Energy Transition spot power price per MWh	**$264**	$121	**$171**	$115
Hedged volume(2)	**1,681**	1,863	**5,320**	5,158
Hedged power price average per MWh	**$80**	$76	**$79**	$67
Fuel and purchased power per MWh(3)	**$60**	$34	**$58**	$33
Carbon compliance cost per MWh(3)	**$13**	$16	**$8**	$17

(1) Realized 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 expected 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 segments in Gas and Energy Transition and carbon compliance cost per MWh includes compliance credits to settle a portion of our GHG carbon pricing obligations.

For the three and nine months ended Sept. 30, 2022, the spot power price increased to $221 per MWh and $145 per MWh, respectively, from $100 per MWh in both periods in 2021.

For the three and nine months ended Sept. 30, 2022, the realized merchant power price per MWh of production increased by $140 and $52 per MWh, respectively, compared with the same periods in 2021. Higher realized merchant power pricing for energy across the fleet was due to higher market prices, increased price volatility 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, 2022, the Hydro ancillary spot power price increased to $128 and $74 per MWh, respectively, compared with the same periods in 2021, due to higher power prices mainly related to higher natural gas prices and stronger weather-driven demand compared to the same periods in 2021.

For the three and nine months ended Sept. 30, 2022, the fuel and purchased power cost per MWh of production increased by $26 per MWh and $25 per MWh, respectively, compared to the same periods in 2021, due to higher natural gas pricing, higher fixed gas transportation costs, partially offset by our hedge positions for gas prices and lower coal costs due to the cessation of mining operations in 2021.

For the three and nine months ended Sept. 30, 2022, carbon compliance costs per MWh of production decreased by $3 per MWh and $9 per MWh, respectively, compared to the same periods in 2021, primarily due to lower carbon emissions from the retirement of our coal fleet and the utilization of compliance credits to settle a portion of our GHG carbon pricing obligation for 2021. Carbon compliance prices have increased to $50 per tonne from $40 per tonne; however, the shift to gas-fired generation effectively lowered our GHG compliance costs as natural gas combustion produces lower GHG emissions than coal combustion.

Segmented Financial Performance and Operating Results

Reporting Segment Changes

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. With the completion of the Clean Energy Transition plan and the announcement of our strategic focus on customer-centered renewable generation, the Company realigned its current operating segments during the fourth quarter of 2021 to better reflect the Company's current strategic focus and to align with the Company's Clean Electricity Growth Plan. The segment reporting changes reflect a corresponding change in how the President and Chief Executive Officer assess the performance of the Company.

The primary changes in 2021, were the elimination of the Alberta Thermal and the Centralia segments and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas are included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets, those facilities not converted to gas and the remaining Centralia unit are included in a new "Energy Transition" segment. No changes have been made to the Hydro, Wind and Solar, Energy Marketing or the Corporate and Other segments. The prior year's metrics were restated to reflect the re-alignment of the operating segments.

Consolidated Results

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	**2022**	2021	**2022**	2021	**2022**	2021
Hydro	**617**	617	**738**	611	**245**	82
Wind and Solar	**930**	783	**685**	718	**42**	55
Renewables	**1,547**	1,400	**1,423**	1,329	**287**	137
Gas			**2,842**	2,913	**195**	155
Energy Transition			**1,167**	1,811	**51**	55
Energy Marketing					**53**	79
Corporate					**(31)**	(24)
Total			**5,432**	6,053	**555**	402
Total earnings (loss) before income taxes					**126**	(441)

	LTA Generation (GWh)[1]		Actual Production (GWh)[2]		Adjusted EBITDA[3]	
9 months ended Sept. 30	**2022**	2021	**2022**	2021	**2022**	2021
Hydro	**1,592**	1,592	**1,644**	1,525	**394**	255
Wind and Solar	**3,451**	2,860	**3,026**	2,675	**219**	186
Renewables	**5,043**	4,452	**4,670**	4,200	**613**	441
Gas			**8,073**	8,370	**365**	385
Energy Transition			**2,510**	3,712	**67**	96
Energy Marketing					**120**	177
Corporate					**(72)**	(56)
Total			**15,253**	16,282	**1,093**	1,043
Total earnings (loss) before income taxes					**346**	(348)

(1) Long-term average production ("LTA Generation (GWh)") is calculated based on our portfolio as at Sept. 30, 2022, 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 30-35 years for the Wind and Solar segments and 36 years for Hydro segment. LTA Generation (GWh) for Energy Transition is not considered as we are currently transitioning these units completely 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. LTA Generation (GWh) for the three and nine months ended Sept. 30, 2022, excluding the Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 846 GWh and 3,176 GWh, respectively.
(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 have proven to be reliable indicators of performance.
(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.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)	**925**	925	**925**	925
LTA Generation (GWh)	**617**	617	**1,592**	1,592
Availability (%)	**97.7**	90.3	**96.6**	91.8
Contract production (GWh)	**125**	98	**292**	262
Merchant production (GWh)	**613**	513	**1,352**	1,263
Total energy production (GWh)	**738**	611	**1,644**	1,525
Ancillary service volumes (GWh)(1)	**797**	657	**2,324**	2,155
Alberta Hydro Assets(2)	**151**	54	**240**	145
Other Hydro assets and other revenue(2)(3)	**12**	12	**34**	32
Alberta Hydro Ancillary services(1)	**102**	30	**172**	125
Environmental attribute revenue	**—**	—	**1**	1
Total gross revenues	**265**	96	**447**	303
Net payment relating to Alberta Hydro PPA(4)	**—**	—	**—**	(4)
Revenues	**265**	96	**447**	299
Fuel and purchased power(5)	**7**	4	**17**	13
Gross margin	**258**	92	**430**	286
OM&A(5)	**12**	10	**33**	29
Taxes, other than income taxes	**1**	—	**3**	2
Adjusted EBITDA	**245**	82	**394**	255
Supplemental Information:				
Gross Revenues per MWh				
Alberta Hydro Assets energy ($/MWh)	**246**	110	**177**	116
Alberta Hydro Assets ancillary ($/MWh)	**128**	46	**74**	58
Sustaining capital	**8**	6	**20**	18

(1) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(2) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro energy include our hydro facilities in BC and Ontario, hydro facilities in Alberta other than the Alberta Hydro Assets and transmission revenues.
(3) Other revenue includes revenues from our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.
(4) The net payment relating to the Alberta Hydro PPA represents the Company's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA that expired on Dec. 31, 2020. The amount in the first and second quarters of 2021 related to adjustments for the final payment under the Alberta PPA.
(5) During the three and nine months ended Sept. 30, 2021, $1 million and $6 million, respectively, related to station service costs for the Hydro segment were reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

Availability, for the three and nine months ended Sept. 30, 2022, increased compared to the same periods in 2021, primarily due to lower planned and unplanned outages at our Alberta Hydro Assets.

Production, for the three and nine months ended Sept. 30, 2022, increased by 127 GWh and 119 GWh, respectively, compared to the same periods in 2021, mainly due to higher water resources in the third quarter from a delayed spring runoff.

Ancillary service volumes, for the three and nine months ended Sept. 30, 2022, increased by 140 GWh and 169 GWh, respectively, compared to the same periods in 2021, due to higher availability and higher water resources in the third quarter from a delayed spring runoff.

Adjusted EBITDA, for the three and nine months ended Sept. 30, 2022, increased by $163 million and $139 million, respectively, compared to the same periods in 2021, primarily due to higher merchant pricing and higher ancillary services realized prices in the Alberta market as well as higher energy and ancillary services volumes due to higher water resources. OM&A costs for the year are higher due to increased insurance premiums for updated replacement value coverage. For further discussion on the Alberta market conditions and pricing, refer to the 2022 Financial Outlook section and Alberta Electricity Portfolio section of this MD&A.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2022, were consistent, compared with the same periods in 2021.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)[1]	**1,906**	1,682	**1,906**	1,682
LTA Generation (GWh)	**930**	783	**3,451**	2,860
Availability (%)	**85.0**	94.0	**83.1**	94.8
Contract production (GWh)	**537**	514	**2,247**	1,964
Merchant production (GWh)	**148**	204	**779**	711
Total energy production (GWh)	**685**	718	**3,026**	2,675
Wind and Solar revenues	**64**	62	**253**	224
Environmental attribute revenue	**3**	14	**33**	23
Revenues[2]	**67**	76	**286**	247
Fuel and purchased power	**6**	4	**20**	11
Carbon compliance	**—**	—	**1**	—
Gross margin[2]	**61**	72	**265**	236
OM&A	**19**	14	**50**	42
Taxes, other than income taxes	**1**	3	**7**	8
Net other operating income[2]	**(1)**	—	**(11)**	—
Adjusted EBITDA[2]	**42**	55	**219**	186
Supplemental information:				
Sustaining capital	**5**	4	**12**	8
Kent Hills wind rehabilitation expenditures[3]	**31**	—	**41**	—
Insurance proceeds - Kent Hills	—	—	**(7)**	—

(1) The gross installed capacity in 2022 includes incremental capacity related to new facilities: Windrise wind facility (206 MW), North Carolina Solar (122 MW) and Oldman wind facility (4 MW).
(2) For details of the adjustments to revenues and net other operating income included in adjusted EBITDA, refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.
(3)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, 2022, decreased compared to the same periods in 2021, primarily as a result of the extended outage at the Kent Hills 1 and 2 wind facilities. For the three months ended Sept. 30, 2022, availability was further impacted by planned and unplanned outages in Ontario. For the nine months ended Sept. 30, 2022, availability was also impacted by early-stage operational issues at our Windrise wind facility.

Production, for the three months ended Sept. 30, 2022, decreased by 33 GWh compared to the same period in 2021, primarily due to lower wind resources across North America driven by higher than average temperatures and lower availability, partially offset by increased production from the addition of the Windrise wind facility commissioned, and North Carolina Solar facility acquired, in the fourth quarter of 2021.

Production, for the nine months ended Sept. 30, 2022, increased by 351 GWh compared to the same period in 2021, primarily due to higher production from the addition of the Windrise wind and North Carolina Solar facilities and higher wind resources across North America, partially offset by lower production from the extended outage at the Kent Hills 1 and 2 wind facilities.

Adjusted EBITDA, for the three months ended Sept. 30, 2022, decreased by $13 million, compared to the same period in 2021, primarily due to lower production, lower environmental attribute revenues and an increase in OM&A related to the addition of the Windrise wind and North Carolina Solar facilities. This was partially offset by higher realized merchant pricing in Alberta.

Adjusted EBITDA, for the nine months ended Sept. 30, 2022, increased by $33 million, compared to the same period in 2021, primarily due to higher production, higher realized merchant pricing in Alberta, higher environmental attribute revenues and recognition of liquidated damages payable to the Company related to turbine availability at the Windrise wind facility. This was partially offset by an increase in transmission rates and OM&A related to the addition of the Windrise wind and North Carolina Solar facilities. A one-time favourable adjustment as a result of the AESO transmission line loss ruling was included in the nine months ended Sept. 30, 2021.

Sustaining capital expenditures for the three months ended Sept. 30, 2022, were consistent with the same period in 2021. Sustaining capital expenditures for the nine months ended Sept. 30, 2022, were $4 million higher compared to the same period in 2021, due to one-time sustaining capital investments in wind control systems in 2022.

The Kent Hills 1 and 2 wind facilities are not currently in operation following the tower failure event that occurred in September 2021. This event has taken approximately 150 MW of gross production offline temporarily as the Company replaces all 50 turbine foundations at the Kent Hills 1 and 2 wind facilities. The extended outage is expected to result in foregone revenue of approximately $3 million per month on an annualized basis (assuming 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.[1] Each turbine at Kent Hills 1 and 2 wind facilities will return to service as soon as its foundation is replaced and the turbine is reassembled and tested.

Kent Hills Wind LP ("KHLP") has entered into agreements with vendors to complete the rehabilitation of the Kent Hills 1 and 2 wind facilities and has commenced execution of its rehabilitation plan. The current estimate of the capital expenditures is approximately $120 million, inclusive of insurance proceeds. Rehabilitation for the Kent Hills 1 and 2 wind facilities is well underway including turbine disassembly and foundation demolition. During the third quarter of 2022, over half of the towers have been fully disassembled including foundation removal. Construction of new foundations has begun with the first concrete pours completed and the new wind turbine components delivered to replace the unit that was damaged. Rehabilitation is targeted to be completed by the second half of 2023 for the Kent Hills 1 and 2 wind facilities.

The Company is actively evaluating all options that may be available to recover the rehabilitation costs from third parties and their insurance providers and intends to pursue claims to recover costs and related damages from those parties.

[1] The Kent Hills 1 and 2 wind facilities lost production is based on average historical wind production.

Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)	**3,084**	3,084	**3,084**	3,084
Availability (%)	**97.8**	88.0	**95.2**	85.6
Contract production (GWh)	**887**	900	**2,657**	2,665
Merchant production (GWh)	**1,974**	2,038	**5,460**	5,834
Purchased power (GWh)	**(19)**	(25)	**(44)**	(129)
Total production (GWh)	**2,842**	2,913	**8,073**	8,370
Revenues[(1)]	**431**	326	**984**	862
Fuel and purchased power[(1)]	**166**	102	**442**	265
Carbon compliance	**26**	33	**56**	104
Gross margin[(1)]	**239**	191	**486**	493
OM&A[(1)]	**49**	42	**138**	127
Taxes, other than income taxes	**5**	4	**13**	11
Net other operating income	**(10)**	(10)	**(30)**	(30)
Adjusted EBITDA[(1)]	**195**	155	**365**	385
Supplemental information:				
Sustaining capital	**8**	31	**16**	97

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

The Gas segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Gas segment is the previous North American Gas segment, Australian Gas segment and the facilities from the previous Alberta Thermal segment which have been converted to gas. The previous Alberta thermal facilities included in the Gas segment include Sheerness Units 1 and 2, Keephills Units 2 and 3 and Sundance Unit 6. Prior periods have been adjusted to be comparable to the current period and reflect operations as coal units.

Availability, for the three and nine months ended Sept. 30, 2022, increased compared to the same periods in 2021, primarily due to higher reliability of the coal-to-gas converted units compared to coal.

Production for the three and nine months ended Sept. 30, 2022, decreased by 71 GWh and 297 GWh, respectively, compared to the same periods in 2021, mainly due to dispatch optimization of our Alberta assets and lower customer demand in Ontario due to a customer outage, partially offset by higher demand in Australia at our South Hedland facility due to the Fortescue Metals Group Ltd. contract and higher production from our Ada cogeneration facility. The nine months ended Sept. 30, 2022, production was positively impacted by higher merchant demand in Ontario.

Adjusted EBITDA, for the three months ended Sept. 30, 2022, increased by $40 million, compared to the same period in 2021. The increase was primarily due to higher merchant pricing in Alberta, net of hedging, lower carbon costs and a favourable change in legal provisions, partially offset by lower production, higher natural gas prices and increased natural gas consumption. Lower carbon costs and increased natural gas consumption in the period were a result of no longer operating on coal.

Adjusted EBITDA, for the nine months ended Sept. 30, 2022, decreased by $20 million, compared to the same period in 2021. The decrease was primarily due to lower production, higher natural gas prices and increased OM&A due to higher incentive accruals related to the Company's performance and increased general operating expenses, partially offset by lower carbon compliance costs and higher merchant pricing in Alberta, net of hedging. Carbon compliance costs were lower due to reductions in GHG emissions, lower production and utilization of our compliance credits to settle a portion of the GHG obligation, partially offset by an increase in the carbon price per tonne. Lower GHG emissions were a direct result of operating exclusively on natural gas in Alberta rather than coal, resulting in changes in the fuel mix ratio. The nine months ended Sept. 30, 2021, was also impacted by the unplanned short-term steam supply outages at the Sarnia cogeneration facility in 2021. Refer to the Alberta Electricity Portfolio section of this MD&A for further details.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2022, decreased by $23 million and $81 million, respectively, compared to the same periods in 2021, mainly due to the coal-to-gas conversions being completed in 2021.

Energy Transition

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)[1]	**671**	1,876	**671**	1,876
Availability (%)	**96.6**	85.6	**77.4**	76.1
Adjusted availability (%)[2]	**96.6**	85.6	**79.8**	80.8
Contract sales volume (GWh)	**839**	839	**2,489**	2,490
Merchant sales volume (GWh)	**1,251**	1,898	**2,780**	3,960
Purchased power (GWh)	**(923)**	(926)	**(2,759)**	(2,738)
Total production (GWh)	**1,167**	1,811	**2,510**	3,712
Revenues[3]	**237**	229	**450**	498
Fuel and purchased power[3]	**167**	137	**332**	295
Carbon compliance	**2**	14	**(1)**	35
Gross margin[3]	**68**	78	**119**	168
OM&A[3]	**17**	23	**50**	69
Taxes, other than income taxes	**—**	1	**2**	5
Net other operating income	**—**	(1)	**—**	(2)
Adjusted EBITDA[3]	**51**	55	**67**	96
Supplemental information:				
Highvale mine reclamation spend	**2**	2	**7**	4
Centralia mine reclamation spend	**4**	4	**11**	8
Sustaining capital	**2**	—	**18**	13

(1) The gross installed capacity for the three and nine months ended Sept. 30, 2022, excludes Keephills Unit 1 (395 MW retired on Dec. 31, 2021), Sundance Unit 5 (406 MW retired on Nov. 1 2021) and Sundance Unit 4 (406 MW retired on March 31, 2022).
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues, fuel and purchased power and OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Energy Transition segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Energy Transition segment are the previous Centralia segment, mine assets and the previous Alberta Thermal segment facilities that were not converted to gas. The previous Alberta thermal facilities included in the Energy Transition segment include Keephills Unit 1 and Sundance Unit 4. Both units have since been retired. Previous periods have been adjusted to be comparable to the current period.

Adjusted availability, increased for the three months ended Sept. 30, 2022, compared to the same period in 2021, mainly due to lower unplanned outages at Centralia Unit 2. Adjusted availability for the nine months ended Sept. 30, 2022, decreased primarily due to the retirement of Sundance Unit 4 and Keephills Unit 1, partially offset by lower planned and unplanned outages at Centralia Unit 2.

Production, for the three and nine months ended Sept. 30, 2022, decreased by 644 GWh and 1,202 GWh, respectively, compared to the same periods in 2021, primarily due to the retirements of Keephills Unit 1 and Sundance Unit 4 and higher economic dispatch at Centralia Unit 2. For the nine months ended Sept. 30, 2022, the decrease in production is partially offset by increased production from higher availability at Centralia Unit 2.

Adjusted EBITDA, for the three and nine months ended Sept. 30, 2022, decreased by $4 million and $29 million, respectively, compared to the same periods in 2021. The decreases were primarily due to lower production and higher purchased power costs incurred due to higher power prices during outages at Centralia Unit 2 in 2022, partially offset by higher merchant pricing at Centralia and lower carbon costs in Alberta. Carbon costs were lower as the facilities in Alberta no longer operated on coal and have now been retired. For the nine months ended Sept. 30, 2022, the Company utilized 0.5 million tonnes of emission credits to settle the 2021 carbon compliance obligation, reducing our carbon compliance costs by $5 million.

Mine reclamation spend for the Highvale and Centralia mines for the three and nine months ended Sept. 30, 2022, increased due to the advancement of reclamation activities compared to the same periods in 2021.

The sustaining capital expenditures for the three and nine months ended Sept. 30, 2022, increased by $2 million and $5 million, respectively, compared to the same period in 2021, primarily due to major maintenance for the Centralia Unit 2.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Revenues[(1)]	**62**	93	**143**	208
OM&A	**9**	14	**23**	31
Adjusted EBITDA[(1)]	**53**	79	**120**	177

(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, for the three and nine months ended Sept. 30, 2022, decreased by $26 million and $57 million, respectively, compared to the same periods in 2021. The decrease for the three and nine months ended Sept. 30, 2022, exceeded segment expectations due to short-term trading of both physical and financial power and gas products across all North American markets but was below 2021 due to the exceptional results in the prior period. The Company was able to capitalize on short-term volatility in the trading markets without materially changing the risk profile of the business unit.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
OM&A	**30**	23	**71**	55
Taxes, other than income taxes	**1**	1	**1**	1
Adjusted EBITDA	**(31)**	(24)	**(72)**	(56)

Adjusted EBITDA	**(31)**	(24)	**(72)**	(56)
Total return swap (gains) losses	**(1)**	1	**—**	(4)
CEWS funding received	**—**	—	**—**	(8)
CEWS funding applied to incremental employment	**1**	1	**4**	2
Adjusted EBITDA excluding impact of total return swap and CEWS	**(31)**	(22)	**(68)**	(66)
Supplemental information:				
Total sustaining capital	**4**	3	**9**	8

Adjusted EBITDA, for the three and nine months ended Sept. 30, 2022, decreased by $7 million and $16 million, respectively, compared to the same periods in 2021. The decrease was mainly due to higher contractor costs, higher incentive accruals reflecting the Company's performance and higher general operating expenses. For the nine months ended Sept. 30, 2021, adjusted EBITDA was positively impacted by the receipt of CEWS proceeds and gains on the total return swap.

For the three and nine months ended Sept. 30, 2022, sustaining capital expenditures were consistent with the same period in 2021.

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, as 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 2021	Q1 2022	Q2 2022	**Q3 2022**
Revenues	610	735	458	**929**
Adjusted EBITDA(1)(2)	243	259	279	**555**
Earnings (loss) before income taxes	(32)	242	(22)	**126**
Cash flow (used in) from operating activities(3)	54	451	(129)	**204**
FFO(1)(2)	186	179	220	**488**
FCF(1)(2)	79	108	145	**393**
Net earnings (loss) attributable to common shareholders	(78)	186	(80)	**61**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(4)	(0.29)	0.69	(0.30)	**0.23**

	Q4 2020	Q1 2021	Q2 2021	Q3 2021
Revenues	544	642	619	850
Adjusted EBITDA(1)(2)	223	322	319	402
Earnings (loss) before income taxes	(168)	21	72	(441)
Cash flow from operating activities	110	257	80	610
FFO(1)(2)	150	223	267	318
FCF(1)(2)	41	141	155	210
Net loss attributable to common shareholders	(167)	(30)	(12)	(456)
Net loss per share attributable to common shareholders, basic and diluted(4)	(0.61)	(0.11)	(0.04)	(1.68)

(1) 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.
(2) The current quarter composition was updated and the previous periods have been reported to be consistent. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) The cash flow used in operating activities for the second quarter of 2022, decreased compared to prior quarters 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.
(4) Basic and diluted earnings (loss) per share attributable to common shareholders is calculated each period using the weighted average common shares outstanding during the period. 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 has also been impacted by the following variations and events:

- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the fourth quarter of 2021 to the third quarter of 2022;
- Accelerated timing of decommissioning cash flows and change in useful lives recognized in the third quarter of 2022;
- Insurance proceeds for the single collapsed tower at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages payable to the Company related to the turbine availability at the Windrise wind facility were recorded at $3 million, $7 million and $1 million in the first three quarters, respectively, of 2022;
- Lower carbon costs in 2022 related to going off coal and the utilization of renewable energy compliance credits to settle a portion of our GHG obligation in the second quarter of 2022;
- Keephills Unit 1 being retired in the fourth quarter of 2021 and Sundance Unit 4 being retired in the first quarter of 2022;
- Acquisition of North Carolina Solar facility in the fourth quarter of 2021;
- The Sundance Unit 5 Repowering project was suspended in the third quarter of 2021 and Sundance Unit 5 was retired during 2021;
- Gains relating to the sale of the Pioneer Pipeline in the second quarter of 2021 and gains on sale of Gas equipment in the third quarter of 2021;
- The unplanned steam supply outages at the Sarnia facility in the second quarter of 2021;
- Alberta Hydro Assets, Keephills Units 1 and 2 and Sheerness began operating on a merchant basis in the Alberta electricity market effective Jan. 1, 2021;
- Revenues declined due to weaker market conditions in 2020;
- Receipt of CEWS funding in 2021;
- Accelerated plans to shut down the Highvale mine resulting in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Sheerness going off coal resulting in the remaining coal supply payments of the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Accelerated shut-down of the Highvale mine increasing mine depreciation included in the cost of coal. Coal inventory write-down incurred in the first three quarters of 2021 and fourth quarter of 2020;
- Coal-related parts and materials inventory write-down incurred in the second and third quarters of 2021;
- The impact of the updated provision estimates for the AESO transmission line loss ruling during the first quarter of 2021 and the fourth quarter of 2020;
- The effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning provisions for retired assets in all periods shown; and
- Current and future tax expense consistently fluctuates with earnings before tax across the quarters. Future tax expense increased from 2021 mainly due to a deferred tax write down taken against part of the Canadian operations and losses on mark to market hedging.

Strategy and Capability to Deliver Results

The Corporate strategy remains unchanged from that disclosed in the 2021 Annual MD&A.

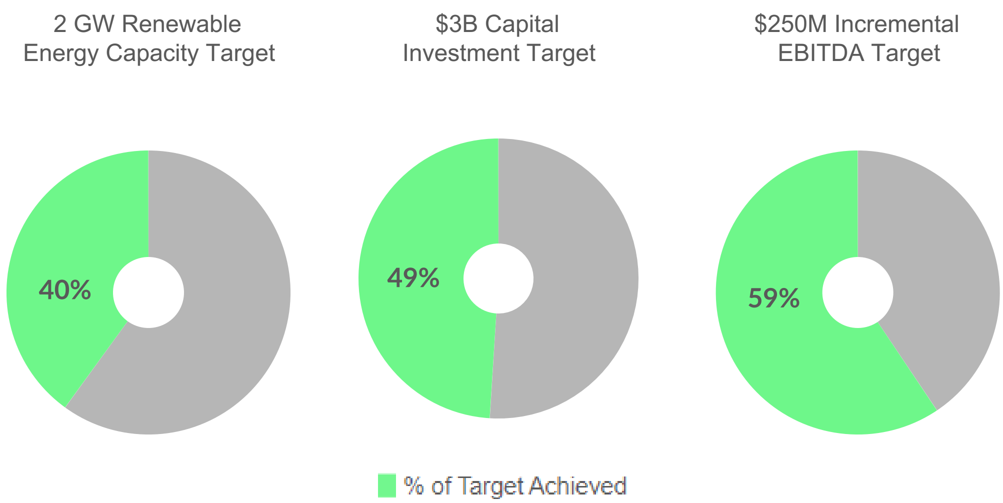
Our goal is to be a leading customer-centered electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high-quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customer needs for clean,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

The Company's enhanced focus on renewable generation and storage solutions for customers is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely for companies to achieve their environment, social and governance ("ESG") ambitions. Refer to the ESG sections within our 2021 Annual MD&A for further details.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind, solar and storage technologies, to increase from 35 per cent in 2020 to approximately 70 per cent by the end of 2025.

On Sept. 28, 2021, the Company announced the strategic targets and a five-year Clean Electricity Growth Plan that sets a focus towards investing in clean energy solutions that meets the needs of our industrial and corporate customers and communities. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and asset-level financing.

As of Nov. 7, 2022, we have made significant progress in 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 billion by the end of 2025.	Ahead of Plan	In 2022, the Company delivered 200 MW of growth during the first quarter with the Horizon Hill wind project. We have begun construction of the Mount Keith 132kV transmission expansion in Australia. Our cumulative progress toward our plan target is 800 MW
	Deliver incremental average annual EBITDA of $250 million.	Ahead of Plan	The Horizon Hill wind project will add incremental EBITDA in the range of US$30 - US$33 million and the Mount Keith 132kV transmission expansion will add incremental EBITDA in the range of AU$6 - AU$7 million. Our cumulative progress towards our incremental EBITDA target is approximately $155 million.
	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 continues to evaluate opportunities to add new development sites to our pipeline. These include acquisitions of individual early-stage development sites, small development portfolios and prospecting of new sites. For the third quarter of 2022, we have grown our renewable development pipeline by approximately 553 MW, in the United States and Canada.
Take a Targeted Approach to Diversification	Grow our asset base in our core geographies of Canada, Australia and the United States to realize diversification and value creation.	On track	The Company has successfully added new contracted renewable assets in each of its three core geographies. We have diversified within the United States market through our North Carolina Solar facility acquisition and the new Oklahoma investments which added three new investment-grade customers.
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 $2.3 billion as at Sept. 30, 2022. The Company returned $34 million in share buybacks in the nine months ended Sept. 30, 2022. The Company increased the annual common share dividend by 10% 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 recently completed an 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 an investment in the Energy Impact Partners Investment ("EIP") Deep Decarbonization Frontier Fund 1, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions. In the second quarter of 2022, the Company made an initial investment of $7 million (US$6 million).
Lead in ESG Policy Development	Actively participate in policy development to ensure the electricity 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 Regulation. Throughout the engagement, TransAlta continues to provide input regarding how to achieve emissions reduction while maintaining necessary reliability and affordability.
Successfully Navigate through the COVID-19 Pandemic	Continue to maintain an effective response to COVID-19 and plan a safe return to our offices.	On track	Continuing to monitor local public health authority and government guidelines in all jurisdictions in which we operate to promote the health and safety of all employees and contractors with our health and safety protocols.

Growth

The Company announced 200 MW of new build projects in the second quarter of 2022. We have established and are continuing to grow our pipeline of potential growth projects. Our pipeline includes 322 MW of advanced stage development projects along with 3,321 to 4,421 MW of projects in earlier stages of development.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the United States 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.

Project	Type	Region	MW	Total project: Estimated spend	Total project: Spent to date	Target completion date[1]	PPA Term[2]	Average annual EBITDA[3]	Status
Canada									
Garden Plain[4]	Wind	AB	130	$190 — $200	$151	Q4 2022	17	$14 - $15	• Fully contracted • Construction underway • All wind turbine components are on site • Turbine erection and commissioning is now underway
United States									
White Rock[5]	Wind	OK	300	US$470 — US$490	US$154	H2 2023	—	US$48 - US$52	• Long-term PPAs executed • All major equipment supply and EPC agreements executed • Detailed design and final permitting on track • Wind turbine component deliveries in-progress • Commenced site construction • On track to be completed on schedule
Horizon Hill[5]	Wind	OK	200	US$300 — US$315	US$44	H2 2023	—	US$30 - US$33	• Long-term PPA executed • All major equipment supply and EPC agreements executed • Wind turbine component deliveries in-progress • Commenced site construction • On track to be completed on schedule
Australia									
Northern Goldfields Solar	Hybrid Solar	WA	48	AU$69 — AU$73	AU$53	H1 2023	16	AU$9 - AU$10	• Construction underway • Solar panel installation is nearing completion • On track to be completed in early 2023
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$50 — AU$53	AU$10	H2 2023	15	AU$6 - AU$7	• EPC Agreement executed • On track to be completed on schedule

(1) H1 or H2 is defined as the first or second half of the year.
(2) The PPA term is confidential for the White Rock wind projects and Horizon Hill wind project.
(3) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Please refer to the Additional IFRS measures and Non-IFRS Measures section of this MD&A for further discussion.
(4) The Garden Plain wind project PPA is fully contracted, with Pembina off-taking 100 MW of the total 130 MW capacity of the facility and the remaining 30 MW contracted to an investment-grade globally recognized customer. Refer to the Significant and Subsequent Events section of this MD&A for further details.
(5) The expected average annual EBITDA and estimated capital spending for the White Rock wind projects and Horizon Hill wind projects have been revised upwards based on the impact of the Inflation Reduction Act of 2022 ("IRA") which results in projects qualifying for 100 per cent production tax credits and incremental payments to the turbine supplier.

Advanced-stage Development

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

Project	Type	Region	Gross Installed Capacity (MW)	Estimated Spend	Average annual EBITDA[1]
Tempest	Wind	Alberta	100	$210 - $230	$20 - $23
SCE Capacity Expansion	Gas	Western Australia	42	AU$80 - AU$100	AU$9 - AU$12
WaterCharger	Battery Storage	Alberta	180	$150 - $180	$14 - $17
Australia Transmission Expansion	Transmission	Western Australia	n/a	AU$34 - AU$36	AU$3 - AU$4

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

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		Gross Installed Capacity (MW)
Early Stage Development				
Canada				
Riplinger Wind	Wind	Alberta		300
Red Rock	Wind	Alberta		100
Willow Creek 1	Wind	Alberta		70
Willow Creek 2	Wind	Alberta		70
Sunhills Solar	Solar	Alberta		80
McNeil Solar	Solar	Alberta		57
Canadian Battery Opportunity	Battery	New Brunswick		10
Canadian Wind Opportunities	Wind	Various		370
Brazeau Pumped Hydro	Hydro	Alberta		300 - 900
Alberta Thermal Redevelopment	Various	Alberta		250 - 500
			Total	**1,607 - 2,457**
United States				
Old Town	Wind	Illinois		185
Trapper Valley	Wind	Wyoming		225
Monument Road	Wind	Nebraska		152
Dos Rios	Wind	Oklahoma		242
Prairie Violet	Wind	Illinois		130
Big Timber	Wind	Pennsylvania		50
Oklahoma Solar	Solar	Oklahoma		100
Other Wind Prospects in the United States	Wind	Various		160
Centralia site Redevelopment	Various	Washington		250 - 500
			Total	**1,494 - 1,744**
Australia				
Goldfields Expansions	Gas, Solar, Wind	Western Australia		170
South Hedland Solar	Solar	Western Australia		50
			Total	**220**
Canada, United States and Australia			**Total**	**3,321 - 4,421**

2022 Financial Outlook

Our overall performance for the third quarter of 2022 was ahead of expectations. During the third quarter of 2022, the Company delivered significantly above financial expectations from its Alberta Electricity Portfolio, including superior revenues through sales of energy and ancillary services of the Alberta Hydro fleet. The Company has revised its guidance upwards, including raising the FCF guidance ranges by approximately $245 million at the midpoint, or 49 per cent. On Nov. 7, 2022, the Board of Directors approved an increase to the annualized dividend to $0.22 per share, beginning with the Jan. 1, 2023 dividend.

Based on results attained to date and our expectations for the balance of the year performance, the Company is revising upwards its outlook range for 2022, which is reflected in the table below:

Measure	Updated Target 2022	Original Target 2022	2021 Actual
Adjusted EBITDA(1)(2)	**$1,380 million - $1,460 million**	$1,065 million - $1,185 million	$1,286 million
FCF(1)(2)	**$725 million - $775 million**	$455 million - $555 million	$585 million
Dividend	**$0.20 per share annualized**	$0.20 per share annualized	$0.20 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Please 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) The 2021 actual adjusted EBITDA and FCF were revised during the second quarter of 2022 to be consistent with the currently defined composition on adjusted EBITDA and FCF. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Range of key 2022 power and gas price assumptions

Market	Updated 2022 Expectations	Original Expectations
Alberta Spot ($/MWh)	**$125 - $150**	$80 - $90
Mid-C Spot (US$/MWh)	**US$55 - US$65**	US$45 - US$55
AECO Gas Price ($/GJ)	**$5.00 - $6.00**	$3.60

Alberta spot price sensitivity: a +/- $1/MWh change in spot price is expected to have a +/- $2 million impact on adjusted EBITDA for the balance of 2022.

Other assumptions relevant to the 2022 financial outlook

	Updated 2022 Expectations	Original Expectations
Sustaining capital	$145 million - $155 million	$150 million - $170 million
Energy Marketing adjusted gross margin	$145 million - $160 million	$95 million - $115 million

Alberta Hedging

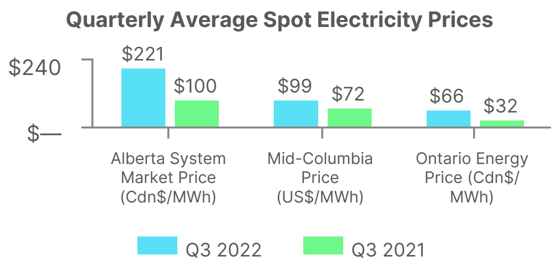
Range of hedging assumptions	Q4 2022	Full year 2023
Hedged production (GWh)	1,850	5,427
Hedge price ($/MWh)	$95	$78
Hedged gas volumes (GJ)	19 million	58 million
Hedge gas prices ($/GJ)	$3.62	$2.24

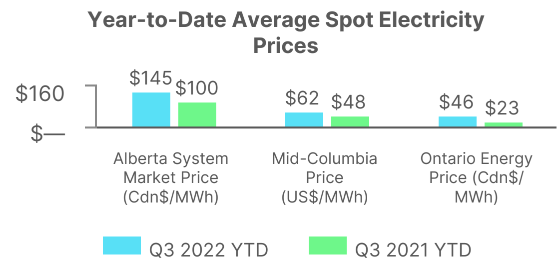
Refer to the 2022 Financial Outlook section in our 2021 Annual MD&A for further details relating to our Outlook and related assumptions.

Operations

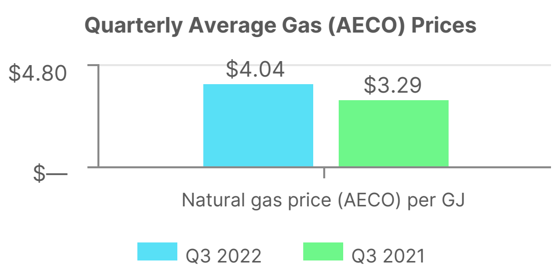
The following provides updates to our original assumptions included in the 2022 Financial Outlook.

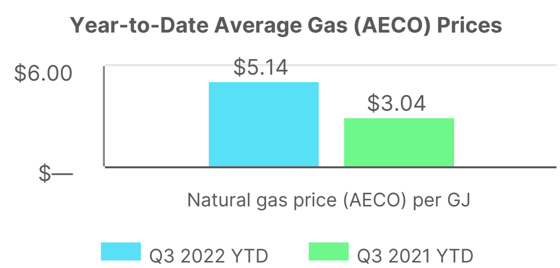
Market Pricing





For the third quarter of 2022, strong merchant pricing levels continued in Alberta and the Pacific Northwest as a result of higher natural gas prices and robust weather-driven demand in both regions. Higher power prices in Alberta were also supported by periods of planned or unplanned outages in the province coinciding with strong demand. Prices in Alberta and the Pacific Northwest for the balance of year are now trading above last year prices primarily due to higher natural gas prices. However, actual power prices will depend on weather in the fourth quarter of 2022. Ontario power prices for both periods of 2022 were higher primarily due to higher natural gas prices.





AECO natural gas prices for nine months ended Sept. 30, 2022, are approximately $2/GJ higher than for the same periods in 2021 due to overall tighter market conditions across North America.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

Category	**Spend for 3 months ended Sept. 30, 2022**	**Spend to date for 9 months ended Sept. 30, 2022**	**Expected spend in 2022**
Total sustaining capital	$ 27	$ 75	$145 - $155

Total sustaining capital expenditures for the nine months ended Sept. 30, 2022, were $69 million lower compared to the same period in 2021, mainly due to lower planned major maintenance turnarounds on the coal-to-gas conversions related to Keephills Unit 2, Sundance Unit 6 and Sheerness Unit 1.

The Kent Hills wind facilities rehabilitation capital expenditure has been segregated from our sustaining capital assumptions range due to the extraordinary nature of this expenditure. Refer to the Wind and Solar section of this MD&A for further details.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities, including the Term Facility (as defined below), the Company entered into during the third quarter of 2022. We currently have access to $2.3 billion in liquidity, including $0.8 billion in cash. We expect to be well-positioned to refinance the upcoming November 2022 debt maturity and the Company plans on utilizing the $400 million Term Facility for refinancing due to timing. The funds required for committed growth, Kent Hills wind facilities rehabilitation, and sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

Financial Position

The following table highlights significant changes in the unaudited interim condensed consolidated statements of financial position from Dec. 31, 2021 to Sept. 30, 2022:

Assets	Sept. 30, 2022	Dec. 31, 2021	Increase/ (decrease)
Current assets			
Cash and cash equivalents	**816**	947	(131)
Trade and other receivables	**1,327**	651	676
Risk management assets	**755**	308	447
Other current assets(1)	**318**	291	27
Total current assets	**3,216**	2,197	1,019
Non-current assets			
Risk management assets	**226**	399	(173)
Property, plant and equipment, net	**5,294**	5,320	(26)
Other non-current assets(2)	**1,309**	1,310	(1)
Total non-current assets	**6,829**	7,029	(200)
Total assets	**10,045**	9,226	819
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**1,279**	689	590
Risk management liabilities	**854**	261	593
Long-term debt and lease liabilities (current)	**722**	844	(122)
Other current liabilities(3)	**105**	137	(32)
Total current liabilities	**2,960**	1,931	1,029
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,487**	2,423	64
Decommissioning and other provisions (long-term)	**651**	779	(128)
Risk management liabilities (long-term)	**247**	145	102
Defined benefit obligation and other long-term liabilities	**184**	253	(69)
Other non-current liabilities(4)	**1,099**	1,102	(3)
Total non-current liabilities	**4,668**	4,702	(34)
Total liabilities	**7,628**	6,633	995
Equity			
Equity attributable to shareholders	**1,538**	1,582	(44)
Non-controlling interests	**879**	1,011	(132)
Total equity	**2,417**	2,593	(176)
Total liabilities and equity	**10,045**	9,226	819

(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 current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable and dividends payable.
(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 $256 million as at Sept. 30, 2022, (Dec. 31, 2021 - $266 million). Our working capital decreased compared to the previous period mainly due to a net increase in risk management liabilities and movements in the collateral accounts. Our collateral received (included in accounts payable and accrued liabilities) is significantly higher at Sept. 30, 2022, compared to Dec. 31, 2021, and is partially offset by the collateral paid to counterparties (included in trade and other receivables). The changes in risk management assets and liabilities and collateral posted and received are largely related to high commodity prices and volatility in the markets. These decreases were partially offset by an increase in trade and other receivables due to higher revenues and the reclassification of the KH Bonds to long-term liabilities as a result of the waiver obtained in the second quarter of 2022.

Current assets increased by $1,019 million to $3,216 million as at Sept. 30, 2022, from $2,197 million as at Dec. 31, 2021, mainly due to higher trade and other receivables due to higher revenues, higher collateral posted and higher risk management assets resulting from volatility in market prices, partially offset by lower cash and cash equivalents. As at Sept. 30, 2022, the Company had provided $315 million (Dec. 31, 2021 - $55 million) of cash collateral related to derivative instruments in a net liability position.

Current liabilities increased by $1,029 million from $1,931 million as at Dec. 31, 2021, to $2,960 million as at Sept. 30, 2022, mainly due to an increase in accounts payable and accrued liabilities due to higher collateral received associated with counterparty obligations and an increase in risk management liabilities primarily due to volatility in market prices across multiple markets; partially offset by repayments of the current portion of long- term debt and the reclassification of the KH Bonds to long-term as a result of the waiver obtained. As at Sept. 30, 2022, the Company held $395 million (Dec. 31, 2021 - $18 million) of cash collateral received related to derivative instruments in a net asset position.

Non-current Assets

Non-current assets as at Sept. 30, 2022, are $6,829 million, a decrease of $200 million from $7,029 million as at Dec. 31, 2021. The decrease was primarily due to lower risk management assets due to volatility in market pricing across multiple markets and contract settlements. PP&E decreased as a result of increased discount rates on decommissioning provisions by $125 million, impairment of assets of $56 million, and depreciation, including an adjustment to the useful lives of certain gas assets which increased depreciation expense by approximately $64 million. These decreases to PP&E were partially offset by additions of $481 million primarily for the construction of the White Rock wind projects, the Garden Plain wind project, the Horizon Hill wind project, the Northern Goldfields solar project, Kent Hills rehabilitation costs and other planned major maintenance and $40 million related to change in timing of estimates for decommissioning and restoration provisions.

Non-current Liabilities

Non-current liabilities as at Sept. 30, 2022, are $4,668 million, a decrease of $34 million from $4,702 million as at Dec. 31, 2021, mainly due to an increase in discount rates driven by market benchmark rates resulting in a decrease in the long-term decommissioning provision of $227 million and a decrease in the defined benefit obligation of $46 million. In addition, these decreases were partially offset by a $90 million increase in the decommissioning provision related to revisions of estimated cash flows, a voluntary contribution of $35 million to improve the funded status of the Sunhills Mining Ltd. Pension Plan, a $64 million increase in long-term debt, net of the scheduled debt repayments, resulting from the reclassification of the KH Bonds to long-term as a result of the waiver obtained and an increase in risk management liabilities of $102 million due to the volatility in across multiple markets and new contracts.

Total Equity

As at Sept. 30, 2022, the decrease in total equity of $176 million was mainly due to net losses on cash flow hedges of $230 million, distributions to non-controlling interests of $126 million, share repurchases under the NCIB of $34 million, and common share and preferred share dividends of $27 million and $21 million, respectively, partially offset by net earnings for the period of $243 million and actuarial gains on defined benefit plans of $36 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, 2022		Dec. 31, 2021	
	$	**%**	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**5**	251	4
Recourse debt - US senior notes	**951**	**17**	888	16
Other	**2**	**—**	4	—
Less: cash and cash equivalents	**(587)**	**(11)**	(703)	(12)
Less: other cash and liquid assets(1)	**(32)**	**(1)**	(19)	—
Net senior unsecured debt	**585**	**10**	421	8
Other debt liabilities				
Exchangeable debentures	**338**	**6**	335	6
Non-recourse debt				
TAPC Holdings LP bond	**96**	**2**	102	2
OCP bond	**241**	**4**	263	5
Lease liabilities	**81**	**2**	78	1
Total net debt - TransAlta Corporation	**1,341**	**24**	1,199	22
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Pingston bond	**45**	**1**	45	1
Melancthon Wolfe Wind bond	**219**	**4**	235	4
New Richmond Wind bond	**116**	**2**	120	2
Kent Hills Wind bond	**209**	**4**	221	4
Windrise Wind bond	**170**	**3**	171	3
Lease liabilities	**23**	**—**	22	—
Less: cash and cash equivalents	**(229)**	**(3)**	(244)	(4)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing(2)	**127**	**2**	135	2
South Hedland non-recourse debt(3)	**679**	**12**	732	13
Total net debt - TransAlta Renewables	**1,359**	**25**	1,437	25
Total consolidated net debt(4)(5)	**2,700**	**49**	2,636	47
Non-controlling interests	**879**	**16**	1,011	18
Exchangeable preferred securities(5)	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**2,879**	**52**	2,901	51
Preferred shares	**942**	**17**	942	17
Contributed surplus, deficit and accumulated other comprehensive income	**(2,283)**	**(41)**	(2,261)	(40)
Total capital	**5,517**	**100**	5,629	100

(1) Includes principal portion of OCP restricted cash and fair value asset (liability) of hedging instruments on debt.
(2) TransAlta Renewables has an economic interest in the entities holding these debts.
(3) TransAlta Renewables has an economic interest in the Australia entities, which includes the AU$789 million senior secured notes.
(4) The tax equity financing for 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.

Credit Facilities

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

As at Sept. 30, 2022	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	753	—	497	Q2 2026
Canadian committed bilateral credit facilities	240	208	—	32	Q2 2024
Term Facility	400	—	—	400	Q3 2024
TransAlta Renewables					
Committed credit facility[2]	700	102	—	598	Q2 2026
Total	**2,590**	**1,063**	**—**	**1,527**	

(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. As at Sept. 30, 2022, we provided cash collateral of $315 million.
(2) TransAlta has letters of credit of $154 million and TransAlta Renewables has letters of credit of $102 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

During the second quarter of 2022, the committed syndicated credit facilities were extended by one year to June 30, 2026, and the committed bilateral credit facilities were extended by one year to June 30, 2024.

During the third quarter of 2022, the Company closed a two-year floating rate term facility with its banking syndicate for $400 million ("Term Facility") with a maturity date of Sept. 7, 2024. The Term Facility has interest rates that vary depending on the option selected (Canadian prime and bankers' acceptances, etc.)

Non-Recourse Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., 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 2022, except in relation to the KH Bonds as discussed below. The next debt service coverage ratio is calculated in the fourth quarter of 2022.

Kent Hills Wind Facilities Rehabilitation

During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon receipt of the waiver, the Company reclassified a portion of the carrying value outstanding for the KH Bonds to non-current liabilities with the exception of the scheduled principal repayments due within the next twelve months from June 30, 2022. In accordance with the supplemental indenture, KHLP cannot make any distributions to its partners until the foundation replacement work has been completed.

Scheduled Debt Maturities

Between 2022 and 2024, we have $877 million of debt maturing, including $548 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the maturing senior notes.

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	
	2022	2021	**2022**	2021
Interest on debt	**42**	41	**123**	121
Interest on exchangeable debentures	**7**	8	**22**	22
Interest on exchangeable preferred shares	**7**	7	**21**	21
Interest income	**(7)**	(2)	**(14)**	(8)
Capitalized interest	**(4)**	(5)	**(8)**	(13)
Interest on lease liabilities	**1**	1	**4**	5
Credit facility fees, bank charges and other interest	**5**	4	**16**	14
Tax shield on tax equity financing	**(1)**	—	**(4)**	1
Accretion of provisions	**16**	9	**35**	23
Net interest expense	**66**	63	**195**	186

Net interest expense for the three and nine months ended Sept. 30, 2022, increased mainly due to higher accretion of provisions and lower capitalized interest, partially offset by higher interest income due to favourable interest rates.

Share Capital

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

As at	**Nov. 7, 2022**	**Sept. 30, 2022**	**Dec. 31, 2021**
	Number of shares (millions)		
Common shares issued and outstanding, end of period	**269.4**	**269.4**	271.0
Preferred shares			
Series A	**9.6**	**9.6**	9.6
Series B	**2.4**	**2.4**	2.4
Series C(1)	**10.0**	**10.0**	11.0
Series D(1)	**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, end of period	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(2)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

(1) During the second quarter of 2022, the Company has converted 1,044,299 of its 11,000,000 currently outstanding Series C Shares, on a one-for-one basis, into Series D Shares.
(2) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the audited annual consolidated financial statements.

Non-Controlling Interests

As at Sept. 30, 2022, the Company owns 60.1 per cent (Sept. 30, 2021 - 60.1 per cent) of TransAlta Renewables. TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol “RNW.” TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

The Company also own 50.01 per cent (Sept. 30, 2021 - 50.01 per cent) of TA Cogen, which owns, operates or has an interest in five natural-gas-fired facilities (Ottawa, Windsor, Fort Saskatchewan and Sheerness Unit 1 and Unit 2).

Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Reported earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2022, were $24 million and $55 million, respectively, a decrease of $3 million and $33 million compared to the same periods in 2021.

Earnings from TA Cogen increased by $15 million for the three months ended Sept. 30, 2022, compared with the same period in 2021, due to higher realized pricing in Alberta, partially offset by higher gas prices, higher gas transportation costs and lower production at Sheerness. Earnings from TA Cogen decreased by $3 million for the nine months ended Sept. 30, 2022, compared to the same period in 2021 due to lower production, higher gas prices and higher transportation rates partially offset by higher realized pricing and lower coal costs.

Earnings from TransAlta Renewables for the three and nine months ended Sept. 30, 2022, decreased by $18 million and $30 million, respectively, compared with the same periods in 2021. This was primarily due to lower finance income related to subsidiaries of TransAlta, higher asset impairment charges, higher interest expense and lower foreign exchange gains. For the nine months ended Sept. 30, 2022, these were partially offset by the recognition of insurance proceeds for the replacement costs for the single collapsed tower at the Kent Hills facility, lower income tax expense and liquidated damages recognized related to turbine availability at the Windrise wind facility. Finance income related to subsidiaries of TransAlta was lower as more distributions were classified as return of capital.

Other Consolidated Analysis

Kent Hills Loan

During the nine months ended Sept. 30, 2022, the loan receivable agreement with KHLP's 17 per cent partner, Natural Forces Technologies Inc., was amended and its original maturity date of Oct. 2, 2022, was extended to October 2027. In addition, KHLP received repayment of $14 million of the KHLP loan receivable, which was required as part of the waiver and amendment made to the KH Bonds. As at Sept. 30, 2022, $41 million (Dec. 31, 2021 — $55 million) was outstanding.

Commitments

Please refer to our Other Consolidated Analysis section of the 2021 Annual MD&A for a complete listing of commitments we have incurred either directly or through interests in joint operations. The Company has entered into the following material contractual commitments, as at Sept. 30, 2022:

During the second quarter of 2022, the Company entered into an engineering, procurement and construction agreement for approximately $37 million (AU$41 million) related to the Mount Keith 132kV Expansion. In addition, the Company entered into agreements for $100 million to complete the rehabilitation at the Kent Hills 1 and 2 wind facilities in 2022.

For updates on the Company's growth projects, refer to the Strategy and Capability to Deliver Results section of this MD&A for further details.

Contingencies

For the current material outstanding contingencies, please refer to Note 36 of the 2021 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

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

The Balancing Pool is claiming entitlement to the 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 Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change in law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing is scheduled for Feb. 6 to 10, 2023. TransAlta holds approximately 1,750,000 EPCs with no recorded book value that were created between 2018-2020, which are at risk as a result of the Balancing Pool's claim.

Keephills Unit 1 Stator Force Majeure

The Balancing Pool and ENMAX were seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX appealed this decision to the Court of Appeal, which was heard on Jan. 27, 2022.

On June 9, 2022, the Court of Appeal released a unanimous decision dismissing ENMAX and the Balancing Pool's application. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills Unit 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta. ENMAX and the Balancing Pool did not seek leave to appeal this decision to the Supreme Court of Canada, which concludes this matter.

Keephills Unit 2 Stator Force Majeure

After the Keephills Unit 1 stator force majeure outage in 2013, it was determined that Keephills Unit 2 could face a similar stator failure before the next planned outage. In response, the Company took Keephills Unit 2 offline between January 31, 2014, and March 15, 2014, to perform a full rewind of the generator stator and claimed force majeure. The Balancing Pool disputed this force majeure event but the dispute was held in abeyance pending the outcome of the Keephills Unit 1 stator force majeure dispute, which was recently concluded. The Company and the Balancing Pool recently settled this dispute and so both stator force majeure claims have been resolved.

Sarnia Outages

The Sarnia cogeneration facility experienced three separate events between May 19, 2021, and June 9, 2021, that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. A root cause failure analysis was completed for the three outages, which concluded that all three outages were within TransAlta (SC) LP's control. As such, liquidated damages previously included in contract liabilities in the amount of $12 million have been paid by TransAlta (SC) LP during the second quarter of 2022.

There have been no other material updates to any of the contingencies in the three and nine months ended Sept. 30, 2022.

Cash Flows

The following chart highlights significant changes in the consolidated statements of cash flows:

	9 months ended Sept. 30		
	2022	2021	**Increase/ (decrease)**
Cash and cash equivalents, beginning of period	**947**	703	244
Provided by (used in):			
Operating activities	**526**	947	(421)
Investing activities	**(341)**	(202)	(139)
Financing activities	**(315)**	(364)	49
Translation of foreign currency cash	**(1)**	(4)	3
Cash and cash equivalents, end of period	**816**	1,080	(264)

Cash provided by operating activities for the nine months ended Sept. 30, 2022, decreased compared with the same period in 2021 primarily due to unfavourable changes in working capital mainly from higher accounts receivable and movements in the collateral accounts related to high commodity prices and volatility in the markets.

Cash used in investing activities for the nine months ended Sept. 30, 2022, increased compared with the same period in 2021, largely due to:

- Previous year included proceeds received on the sale of the Pioneer Pipeline ($128 million); and
- Higher cash spend on project construction activities in PP&E ($137 million) partially offset by:
  - Lower non-cash working capital related to the timing of construction payables for the assets under construction ($109 million);
  - Higher loan receivable receipts ($14 million); and
  - Higher restricted cash receipts related to funding principal debt repayments ($8 million).

Cash used in financing activities for the nine months ended Sept. 30, 2022, decreased compared with the same period in 2021, largely due to:

- Lower repayments under the Company's credit facilities ($114 million); partially offset by:
  - Higher repayments on long-term debt ($17 million);
  - Higher common share repurchases under the NCIB ($24 million);
  - Higher dividends paid on common shares and preferred shares ($6 million);
  - Increased distributions paid to subsidiaries' non-controlling interests ($9 million); and
  - Lower proceeds on issuances of common shares ($7 million).

Financial Instruments

Refer to Note 15 of the notes to the audited annual 2021 consolidated financial statements, and Note 11 and 12 of our unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2022, 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, 2022, Level III instruments had a net liability carrying value of $611 million (Dec. 31, 2021 - net asset of $159 million), which are primarily attributable to volatility in market prices across multiple markets on both existing contracts and new contracts as well as contract settlements.

Our risk management profile and practices have not changed materially from Dec. 31, 2021.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the unaudited interim condensed consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the 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, 2022, and 2021. 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 2021 consolidated financial statements and the unaudited interim condensed consolidated statements of earnings (loss) for the three and nine months ended Sept. 30, 2022, 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, or as an alternative for, 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 Financial Non-IFRS 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

In the fourth quarter of 2021, comparable EBITDA was relabeled as adjusted EBITDA to align with industry standard terminology. 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 business profitability. In the second quarter of 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and Energy Marketing segment in the period in which the transactions occur. Accordingly, the Company has applied this composition to all previously reported periods. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends. Adjusted EBITDA is a non-IFRS measure. The following are descriptions of the adjustments made.

Adjustments to revenue

- Certain assets we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe 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.
- Gains and losses related to closed positions effectively settled by offsetting positions with exchanges have been recorded in the period the positions are settled.

Adjustments to fuel and purchased power

- We adjust for depreciation on our mining equipment included in fuel and purchased power.
- We adjust for items resulting from the decision to accelerate being off-coal and accelerating the shut-down of the Highvale mine at the end of 2021 as it is not reflective of ongoing business performance. Within fuel and purchased power this included coal inventory write-downs.
- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

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

- Asset impairment charges are removed as these are accounting adjustments that impact depreciation and amortization and do not reflect current 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 to Net Other Operating (Income) loss

- 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. Refer to the Wind and Solar section of this MD&A for further details.

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 Skookumchuck wind facility in our total adjusted EBITDA. In addition, in the Wind and Solar segment 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 equity interest for the EMG International LLC ("EMG") 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 from operations

- Includes 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 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 accelerating the shut-down of the Highvale mine by the end of 2021, the write-down on parts and material inventory for our coal operations and voluntary contribution made to fund the Sunhills Mining Ltd. Pension Plan (under the "Clean energy transition provisions and adjustments").
- Cash received/paid on closed positions are reflected in the period that the position is settled.

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 the 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 Financial Non-IFRS 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 a non-IFRS ratios.

Supplementary Financial Measures

Financial highlights presented on a proportional basis of TransAlta Renewables, deconsolidated adjusted EBITDA, deconsolidated FFO and deconsolidated net debt to deconsolidated adjusted EBITDA are supplementary financial measures the Company uses to present adjusted EBITDA on a deconsolidated basis and excludes the portion of TransAlta Renewables and TA Cogen that are not owned by TransAlta. Refer to the Financial Highlights on a Proportional Basis of TransAlta Renewables and Key Financial Non-IFRS Ratios sections of this MD&A for additional information.

The Alberta Electricity Portfolio metrics disclosed are also supplementary financial measures used to present the gross margin by segment within the Alberta Electricity Portfolio. 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, 2022:

	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	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 (gain) loss	—	53	47	6	46	—	152	—	(152)	—
Realized (gain) 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(4)	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) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) 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, 2021:

	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	96	55	384	231	86	1	853	(3)	—	850
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	21	(71)	(2)	(14)	—	(66)	—	66	—
Realized loss on closed exchange positions	—	—	—	—	21	—	21	—	(21)	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	96	76	326	229	93	1	821	(3)	32	850
Fuel and purchased power[4]	4	4	129	190	—	1	328	—	—	328
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(26)	(48)	—	—	(74)	—	74	—
Coal inventory write-down	—	—	—	(5)	—	—	(5)	—	5	—
Adjusted fuel and purchased power	4	4	102	137	—	1	248	—	80	328
Carbon compliance	—	—	33	14	—	—	47	—	—	47
Gross margin	92	72	191	78	93	—	526	(3)	(48)	475
OM&A[4]	10	14	42	28	14	23	131	(1)	—	130
Reclassifications and adjustments:										
Parts and materials write-down	—	—	—	(5)	—	—	(5)	—	5	—
Adjusted OM&A	10	14	42	23	14	23	126	(1)	5	130
Taxes, other than income taxes	—	3	4	1	—	1	9	—	—	9
Net other operating (income) loss	—	—	(10)	57	—	—	47	—	—	47
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(58)	—	—	(58)	—	58	—
Adjusted net other operating income	—	—	(10)	(1)	—	—	(11)	—	58	47
Adjusted EBITDA[5]	82	55	155	55	79	(24)	402			
Equity income										1
Finance lease income										6
Depreciation and amortization										(123)
Asset impairment charges										(575)
Net interest expense										(63)
Foreign exchange gain										1
Gain on sale of assets and other										23
Loss before income taxes										(441)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the three months ended Sept. 30, 2021, $1 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(5) 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 9 months ended Sept. 30, 2022:

	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	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 (gain) 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(4)	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) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) 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 9 months ended Sept. 30, 2021:

	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	299	225	937	471	185	6	2,123	(12)	—	2,111
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	22	(122)	27	(26)	—	(99)	—	99	—
Realized loss on closed exchange positions	—	—	1	—	49	—	50	—	(50)	—
Decrease in finance lease receivable	—	—	30	—	—	—	30	—	(30)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	299	247	862	498	208	6	2,120	(12)	3	2,111
Fuel and purchased power[4]	13	11	347	411	—	6	788	—	—	788
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Mine depreciation	—	—	(79)	(100)	—	—	(179)	—	179	—
Coal inventory write-down	—	—	—	(16)	—	—	(16)	—	16	—
Adjusted fuel and purchased power	13	11	265	295	—	6	590	—	198	788
Carbon compliance	—	—	104	35	—	—	139	—	—	139
Gross margin	286	236	493	168	208	—	1,391	(12)	(195)	1,184
OM&A[4]	29	42	129	97	31	55	383	(2)	—	381
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(28)	—	—	(30)	—	30	—
Adjusted OM&A	29	42	127	69	31	55	353	(2)	30	381
Taxes, other than income taxes	2	8	11	5	—	1	27	(1)	—	26
Net other operating (income) loss	—	—	(30)	56	—	—	26	—	—	26
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(58)	—	—	(58)	—	58	—
Adjusted net other operating income	—	—	(30)	(2)	—	—	(32)	—	58	26
Adjusted EBITDA[5]	255	186	385	96	177	(56)	1,043			
Equity income										5
Finance lease income										19
Depreciation and amortization										(395)
Asset impairment charges										(620)
Net interest expense										(186)
Foreign exchange gain										22
Gain on sale of assets and other										56
Loss before income taxes										(348)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the nine months ended Sept. 30, 2021, $6 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(5) 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 table below reconciles our cash flow from operating activities to our FFO and FCF:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Cash flow from operating activities	**204**	610	**526**	947
Change in non-cash operating working capital balances	**276**	(378)	**252**	(322)
Cash flow from operations before changes in working capital	**480**	232	**778**	625
Adjustments				
Share of adjusted FFO from joint venture(1)	**2**	3	**7**	7
Decrease in finance lease receivable	**12**	10	**34**	30
Clean energy transition provisions and adjustments(2)(4)	**27**	49	**35**	85
Realized (gain) loss on closed exchange positions	**(42)**	21	**16**	50
Other(3)	**9**	3	**17**	11
FFO(5)	**488**	318	**887**	808
Deduct:				
Sustaining capital(1)	**(27)**	(44)	**(75)**	(144)
Productivity capital	**(1)**	(1)	**(3)**	(2)
Dividends paid on preferred shares	**(11)**	(9)	**(31)**	(29)
Distributions paid to subsidiaries' non-controlling interests	**(54)**	(52)	**(126)**	(121)
Principal payments on lease liabilities and other(1)	**(2)**	(2)	**(6)**	(6)
FCF(5)	**393**	210	**646**	506
Weighted average number of common shares outstanding in the period	**271**	271	**271**	271
FFO per share(5)	**1.80**	1.17	**3.27**	2.98
FCF per share(5)	**1.45**	0.77	**2.38**	1.87

(1) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(2) Includes a write-down on parts and material inventory, and coal inventory for our coal operations in 2021 to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit.
(3) Other consists of production tax credits which is a reduction to tax equity debt.
(4) During the third quarter of 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million.
(5) These items are 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 table below bridges our adjusted EBITDA to our FFO and FCF:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Adjusted EBITDA[1]	**555**	402	**1,093**	1,043
Provisions	**(5)**	(20)	**5**	(25)
Interest expense	**(47)**	(50)	**(151)**	(149)
Current income tax expense	**(11)**	(23)	**(36)**	(58)
Realized foreign exchange gain (loss)	**3**	5	**18**	2
Decommissioning and restoration costs settled	**(9)**	(5)	**(23)**	(13)
Other non-cash items	**2**	9	**(19)**	8
FFO[3]	**488**	318	**887**	808
Deduct:				
Sustaining capital[2]	**(27)**	(44)	**(75)**	(144)
Productivity capital	**(1)**	(1)	**(3)**	(2)
Dividends paid on preferred shares	**(11)**	(9)	**(31)**	(29)
Distributions paid to subsidiaries' non-controlling interests	**(54)**	(52)	**(126)**	(121)
Principal payments on lease liabilities and other [2]	**(2)**	(2)	**(6)**	(6)
FCF[3]	**393**	210	**646**	506

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(2) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(3) These items are not defined and has no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to cash flow from operating activities above.

Financial Highlights on a Proportional Basis of TransAlta Renewables

The proportionate financial information below reflects TransAlta's share of TransAlta Renewables relative to TransAlta's total consolidated figures. The financial highlights presented on a proportional basis of TransAlta Renewables are supplementary financial measures to reflect TransAlta Renewables' portion of the consolidated figures.

Consolidated Results

The following table reflects the generation and summary financial information on a consolidated basis during the period:

	Actual Generation (GWh)		Adjusted EBITDA(1)		Earnings (loss) before income taxes	
3 months ended Sept. 30	**2022**	2021	**2022**	2021	**2022**	2021
TransAlta Renewables						
Hydro	**168**	136	**7**	6		
Wind and Solar(2)	**685**	718	**32**	40		
Gas(2)	**836**	862	**54**	60		
Corporate	**—**	—	**(5)**	(4)		
TransAlta Renewables before adjustments	**1,689**	1,716	**88**	102	**(26)**	21
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(674)**	(676)	**(35)**	(40)	**10**	(8)
Portion of TransAlta Renewables owned by TransAlta Corporation	**1,015**	1,040	**53**	62	**(16)**	13
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**570**	475	**238**	76		
Wind and Solar	**—**	—	**10**	15		
Gas	**2,006**	2,051	**141**	95		
Energy Transition	**1,167**	1,811	**51**	55		
Energy Marketing	**—**	—	**53**	79		
Corporate	**—**	—	**(26)**	(20)		
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**4,758**	5,377	**520**	362	**136**	(449)
Non-controlling interests	**674**	676	**35**	40	**(10)**	8
TransAlta Consolidated	**5,432**	6,053	**555**	402	**126**	(441)

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(2) Wind and Solar and Gas segments include those assets that TransAlta Renewables holds an economic interest in.

9 months ended Sept. 30	Actual Generation (GWh) 2022	Actual Generation (GWh) 2021	Adjusted EBITDA[1] 2022	Adjusted EBITDA[1] 2021	Earnings (loss) before income taxes 2022	Earnings (loss) before income taxes 2021
TransAlta Renewables						
Hydro	**368**	338	**15**	14		
Wind and Solar[2]	**3,026**	2,675	**188**	172		
Gas[2]	**2,505**	2,374	**166**	151		
Corporate	**—**	—	**(16)**	(15)		
TransAlta Renewables before adjustments	**5,899**	5,387	**353**	322	**41**	110
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(2,354)**	(2,141)	**(141)**	(127)	**(16)**	(43)
Portion of TransAlta Renewables owned by TransAlta Corporation	**3,545**	3,246	**212**	195	**25**	67
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**1,276**	1,187	**379**	241		
Wind and Solar	**—**	—	**31**	14		
Gas	**5,568**	5,996	**199**	234		
Energy Transition	**2,510**	3,712	**67**	96		
Energy Marketing	**—**	—	**120**	177		
Corporate	**—**	—	**(56)**	(41)		
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**12,899**	14,141	**952**	916	**330**	(391)
Non-controlling interests	**2,354**	2,141	**141**	127	**16**	43
TransAlta Consolidated	**15,253**	16,282	**1,093**	1,043	**346**	(348)

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(2) Wind and Solar and Gas segments include those assets that TransAlta Renewables holds an economic interest in.

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

	Sept. 30, 2022	Dec. 31, 2021
Period-end long-term debt[1]	**3,209**	3,267
Exchangeable securities	**338**	335
Less: Cash and cash equivalents	**(816)**	(947)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[2]	**671**	671
Other[3]	**(32)**	(19)
Adjusted net debt[4]	**3,370**	3,307
Adjusted EBITDA[5]	**1,336**	1,286
Adjusted net debt to adjusted EBITDA (times)	**2.5**	2.6

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the unaudited interim condensed consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.
(3) Includes principal portion of TransAlta OCP restricted cash ($17 million for the nine months ended Sept. 30, 2022) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the unaudited interim condensed consolidated statements of financial position).
(4) The tax equity financing for Skookumchuck wind facility, an equity accounted joint venture, is not represented in the amounts. 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.
(5) 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 assess our ability to pay off debt. Our adjusted net debt to adjusted EBITDA ratio was lower as at Sept. 30, 2022 compared to 2021 as a result of debt repayments, lower cash and cash equivalents and higher adjusted EBITDA.

Deconsolidated Adjusted EBITDA by Segment

We invest in our assets directly as well as with joint venture partners. Deconsolidated financial information is a supplementary financial measure and is not intended to be, presented in accordance with IFRS.

Adjusted EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated EBITDA is used in key planning and credit metrics and segment results highlight the operating performance of assets held directly at TransAlta that are comparable from period to period.

A reconciliation of adjusted EBITDA to deconsolidated adjusted EBITDA by segment results is set out below:

	3 months ended Sept. 30, 2022			3 months ended Sept. 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**245**	**7**		82	6	
Wind and Solar	**42**	**32**		55	40	
Gas	**195**	**54**		155	60	
Energy Transition	**51**	**—**		55	—	
Energy Marketing	**53**	**—**		79	—	
Corporate	**(31)**	**(5)**		(24)	(4)	
Adjusted EBITDA	**555**	**88**	**467**	402	102	300
Less: TA Cogen adjusted EBITDA			**(70)**			(41)
Less: EBITDA from joint venture investments[1]			**—**			(2)
Add: Dividend from TransAlta Renewables			**38**			38
Add: Dividend from TA Cogen			**18**			22
Deconsolidated TransAlta adjusted EBITDA[1]			**453**			317

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

	9 months ended Sept. 30, 2022			9 months ended Sept. 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**394**	**15**		255	14	
Wind and Solar	**219**	**188**		186	172	
Gas	**365**	**166**		385	151	
Energy Transition	**67**	**—**		96	—	
Energy Marketing	**120**	**—**		177	—	
Corporate	**(72)**	**(16)**		(56)	(15)	
Adjusted EBITDA	**1,093**	**353**	**740**	1,043	322	721
Less: TA Cogen adjusted EBITDA			**(99)**			(104)
Less: EBITDA from joint venture investments[1]			**—**			(9)
Add: Dividend from TransAlta Renewables			**113**			113
Add: Dividend from TA Cogen			**28**			25
Deconsolidated TransAlta adjusted EBITDA[1]			**782**			746

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

Deconsolidated FFO

The Company has set capital allocation targets based on deconsolidated FFO available to shareholders. Deconsolidated financial information is a supplementary financial measure and is not defined and has no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details. Deconsolidated FFO for the periods ended Sept. 30, 2022 and 2021 is detailed below:

	3 months ended Sept. 30, 2022			3 months ended Sept. 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**204**	**37**		610	83	
Change in non-cash operating working capital balances	**276**	**(4)**		(378)	(23)	
Cash flow from operations before changes in working capital	**480**	**33**		232	60	
Adjustments:						
Decrease in finance lease receivable	**12**	**—**		10	—	
Clean energy transition provisions and adjustments(1)	**27**	**—**		49	—	
Realized (gain) loss on closed exchange positions	**(42)**	**—**		21	—	
Share of FFO from joint venture(2)	**2**	**—**		3	—	
Finance income - economic interests	**—**	**(2)**		—	(19)	
FFO - economic interests(3)	**—**	**37**		—	46	
Other(4)	**9**	**—**		3	—	
FFO	**488**	**68**	**420**	318	87	231
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(29)**			(25)
Less: Share of adjusted FFO from joint venture(2)			**—**			(3)
Deconsolidated TransAlta FFO			**429**			241

(1) Clean energy transition adjustments during the third quarter of 2021, include write-down on parts and material inventory for the coal operations, write-down on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of previously recognized deferred asset, as there were no sufficient capital or operating expenditures incurred to utilize the remaining credit. During the third quarter of 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million.
(2) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.
(3) FFO - economic interests calculated as Free Cash Flow economic interests plus sustaining capital expenditures economic interests and tax equity distributions and plus/minus currency adjustment.
(4) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.

	9 months ended Sept. 30, 2022			9 months ended Sept. 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**526**	**168**		947	265	
Change in non-cash operating working capital balances	**252**	**(2)**		(322)	(57)	
Cash flow from operations before changes in working capital	**778**	**166**		625	208	
Adjustments:						
Decrease in finance lease receivable	**34**	**—**		30	—	
Clean energy transition provisions and adjustments[1]	**35**	**—**		85	—	
Realized loss on closed exchange positions	**16**	**—**		50	—	
Share of FFO from joint venture[2]	**7**	**—**		7	—	
Finance income - economic interests	**—**	**(24)**		—	(68)	
FFO - economic interests[3]	**—**	**136**		—	131	
Other[4]	**17**	**—**		11	—	
FFO	**887**	**278**	**609**	808	271	537
Dividend from TransAlta Renewables			**113**			113
Distributions to TA Cogen's Partner			**(51)**			(42)
Less: Share of adjusted FFO from joint venture[2]			**—**			(7)
Deconsolidated TransAlta FFO			**671**			601

(1) Clean energy transition adjustments during the third quarter of 2021, include write-down on parts and material inventory for the coal operations, write-down on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of previously recognized deferred asset, as there were no sufficient capital or operating expenditures incurred to utilize the remaining credit. During the third quarter of 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million.
(2) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.
(3) FFO - economic interests calculated as Free Cash Flow economic interests plus sustaining capital expenditures economic interests and tax equity distributions and plus/minus currency adjustment.
(4) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.

Deconsolidated Net Debt to Deconsolidated Adjusted EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage. Deconsolidated financial information is a supplementary financial measure and is not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at	**Sept. 30, 2022**	Dec. 31, 2021
Adjusted net debt(1)	**3,370**	3,307
Add: TransAlta Renewables cash and cash equivalents	**229**	244
Less: TransAlta Renewables long-term debt	**(782)**	(814)
Less: US tax equity financing and South Hedland debt(2)	**(806)**	(867)
Deconsolidated net debt	**2,011**	1,870
Deconsolidated adjusted EBITDA(3)(5)	**911**	875
Deconsolidated net debt to deconsolidated adjusted EBITDA(4) (times)	**2.2**	2.1

(1) Refer to the Adjusted Net Debt to Adjusted EBITDA calculation under the Key Financial Non-IFRS Ratios section of this MD&A for the reconciliation and composition of Adjusted net debt.
(2) Relates to assets where TransAlta Renewables has economic interests.
(3) Refer to the Deconsolidated Adjusted EBITDA by Segment section of this MD&A for the reconciliation and composition of deconsolidated adjusted EBITDA and the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the composition of adjusted EBITDA.
(4) The non-IFRS ratio is not a standardized financial measure under IFRS and might not be comparable to similar financial measures disclosed by other issuers.
(5) Last 12 months.

Our deconsolidated net debt to deconsolidated adjusted EBITDA ratio for the nine months ended Sept. 30, 2022, increased compared with 2021, due to higher deconsolidated net debt and deconsolidated adjusted EBITDA. Higher deconsolidated net debt is a result of decreases in cash balances offset by scheduled repayments on corporate debt.

Critical Accounting Policies and 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.

Estimates to the extent to which geopolitical events such as the Russia-Ukraine conflict may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods are also subject to significant uncertainty. Uncertainty related to COVID-19 and the geopolitical events has been considered in our estimates as at and for the nine months period ended Sept. 30, 2022. Refer to the Governance and Risk Management section of this MD&A for further details.
The following were material changes in estimates:

Asset Impairments

Wind and Solar

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.

Hydro

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.

Change in Estimate - Decommissioning provision
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.

For the three months ended Sept. 30, 2022, the Company accelerated the expected timing on decommissioning and restoration for certain gas assets. This increased the decommissioning and restoration provision by $79 million resulting in an increase in PP&E of $29 million on operating assets and recognition of a $50 million impairment charge in net earnings related to retired assets. In the second quarter of 2022, an additional increase to decommissioning and restoration of $11 million was recognized in relation to an asset in the Gas segment.

For the nine months ended Sept. 30, 2022, the decommissioning and restoration provisions have decreased by $227 million due to a significant increase in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 6.8 to 9.6 per cent as at Sept. 30, 2022 (Dec. 31, 2021 — 3.6 to 6.5 per cent). This has resulted in a corresponding decrease in PP&E of $125 million on operating assets and recognition of $102 million impairment reversal in net earnings related to retired assets.

Change in Estimate - Useful Lives
During the third quarter of 2022, the Company adjusted the useful lives of certain assets included in the Gas segment to reflect changes made based on the future operating expectations of the assets. This resulted in an increase of $64 million in depreciation expense that was recognized in the Condensed Consolidated Statement of Earnings in the third quarter of 2022.

Defined Benefit Obligation
The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates, largely driven by increases in market benchmark rates, the defined benefit obligation decreased by $46 million for the nine months ended Sept. 30, 2022. A 1 per cent increase in discount rates would have a $38 million impact on the defined benefit obligation.

In addition, during the third quarter of 2022, the Company made a voluntary contribution of $35 million to further improve the funded status of the Sunhills Mining Ltd. Pension Plan and to support the employees affected by the closure of the Highvale mine and our transition off-coal to cleaner sources. This contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letter of credit.

Refer to Note 2(P) of the Company's 2021 audited annual consolidated financial statements for further details on the Significant Accounting Judgments and Key Sources of Estimation Uncertainty.

Accounting Changes

Current Accounting Policy Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's audited annual consolidated financial statements for the year ended Dec. 31, 2021, except for the adoption of new standards effective as of Jan. 1, 2022.

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the International Accounting Standards Board ("IASB") issued Onerous Contracts — Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted in the adoption of the amendments on Jan. 1, 2022.

Future Accounting Policy Changes
Please refer to Note 3 of the audited annual 2021 consolidated financial statements for the future accounting policies impacting the Company. In the three and nine months ended Sept. 30, 2022, no additional future accounting policy change impacting the Company were identified.

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

Governance and Risk Management
Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in a position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multi-level risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate and the political environments and structures with which we interface.

During the three and nine months ended Sept. 30, 2022, the global economy continued to recover from the COVID-19 pandemic. On Feb. 24, 2022, the Russian government's invasion of Ukraine set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. The Company continues to mitigate inflationary and supply chain risks pertaining to current development projects by locking in the prices of key materials where possible and employing the other supply chain risk mitigation strategies described in our 2021 Annual MD&A. A prolonged conflict and recent inflationary and supply chain dynamics may impact future construction project costs with the risk of rising prices on key materials. Accordingly, as the Russia-Ukraine conflict continues to evolve and the indirect impacts of the Russia-Ukraine conflict and rising inflation rates within the global markets remain uncertain at this time, management continues to monitor and assess the impacts.

Interest Rate Risk
Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact our borrowing costs. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

At Sept. 30, 2022, approximately 3 per cent (Dec. 31, 2021 – 3 per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps. During the third quarter of 2022, the interest rate swap agreements with a notional amount of US$150 million referencing the three-month LIBOR were replaced with swap agreements referencing the Secured Overnight Financing Rate ("SOFR"). Existing interest rate swap agreements with a notional amount of US$150 million reference the US Treasury Bond yield. The maturity dates on all swap agreements have been extended.

The Company has US$400 million of debt maturing in November 2022 and we have hedged US$300 million of the underlying debt to reduce the interest rate risk.

Please refer to the Governance and Risk Management section of our 2021 Annual MD&A and Note 12 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2021.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2021 annual MD&A for further details that supplement the recent developments as discussed below:

Canada

Federal

The Government of Canada’s Department of Environment and Climate Change Canada (“ECCC”) continues engagement on the proposed new Clean Electricity Regulation ("CER"), originally known as the Clean Electricity Standards ("CES"), to achieve a net-zero electricity sector in Canada by 2035. ECCC is consulting on the CER design through the fall of 2022. It is expected that the draft regulation will be published in the Canada Gazette, Part I at the end of 2022 or early in 2023. Further consultation on the draft regulation will occur in 2023.

On Nov. 3, 2022, the Government of Canada announced new tax credits for renewable generation, energy storage, and hydrogen production. TransAlta will engage the Department of Finance as it finalizes the parameters of these tax credits.

Ontario

In the third quarter of 2022, the Ontario government undertook a consultation on proposed changes to its Emissions Performance Standards ("EPS") carbon pricing system in advance of the provincial submission into the federal review process. The federal review process will occur in the fourth quarter of 2022.

TransAlta has been actively involved in the consultation process and continues to advocate for an approach that supports our operations in the province. We do not anticipate any adverse impact from these policy proposals as TransAlta passes compliance costs and savings on to customers through our existing contracts.

In 2022, the IESO moved forward with procurement and planning to meet the upcoming capacity needs in the province in the short, medium and long-term. The IESO completed its medium-term RFP to procure capacity from existing generators and awarded five facilities including TransAlta's Sarnia cogeneration facility and Melancthon 1 wind facility with new contracts that will run from May 1, 2026 to April 30, 2031. It is expected that Sarnia's existing capacity contract with the IESO will be extended to the start date of the new contract. In addition, the IESO is moving forward with long-term procurement processes to secure up to 4,000 MW of capacity with commercial delivery by 2025-2027. TransAlta has qualified in the long-term procurement process. The contract awards for the procurements will be announced in 2023.

Alberta

In August 2022, the Government of Alberta launched a consultation on changes to the Technology Innovation and Emissions Reduction ("TIER") Regulation, which governs the province's carbon pricing regime. The review is meant to amend the regulations to meet the federal carbon pricing benchmark.

Key issues under consideration include aligning with the federal carbon price escalator to $170/tonne by 2030, increasing the stringency of TIER emissions performance standards and ensuring net demand for emissions credits deliver a consistent marginal price of carbon. TransAlta has been closely engaging in the consultations and continues to advocate for an approach that supports a predictable investment and operating environment.

United States

On Aug. 16, 2022, the Inflation Reduction Act 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 US mid-term elections will be held on Nov. 8, 2022. Changes in Congress and the Senate could shift the focus of the government, specifically in terms of climate policy. TransAlta will continue to monitor the results of the mid-term elections along with the developments in the implementation of the IRA.

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

We continue to see state-level policy announcements focused on moving away from coal and toward greater reliance on renewables, hydrogen and energy storage. We see low risk to our existing Australian assets, but policy support for continued industrial decarbonization that may support future growth.

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 nine months ended Sept. 30, 2022, the majority of our workforce supporting and executing our ICFR and DC&P returned to work and continue to work remotely 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 audited annual 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.

In accordance with the provisions of National Instrument 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar, which the Company acquired on Nov. 5, 2021. North Carolina Solar facility was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2021, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's audited annual consolidated financial statements for the year ended Dec. 31, 2021.

Consistent with the evaluation at Dec. 31, 2021, the scope of the evaluation does not include controls over financial reporting of the assets acquired through the North Carolina Solar facility acquisition, which the Company acquired on Nov. 5, 2021. North Carolina Solar's total and net assets represented approximately 2 per cent and 3 per cent of the Company's total and net assets and 1 per cent of the Company's total net earnings, respectively, as at Sept. 30, 2022.

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, 2022, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2022**	2021	**2022**	2021
Revenues (Note 3)	**929**	850	**2,122**	2,111
Fuel and purchased power (Note 4)	**348**	328	**817**	788
Carbon compliance (Note 4)	**23**	47	**51**	139
Gross margin	**558**	475	**1,254**	1,184
Operations, maintenance and administration (Note 4)	**135**	130	**364**	381
Depreciation and amortization (Note 14)	**179**	123	**411**	395
Asset impairment charges (Note 5)	**70**	575	**4**	620
Taxes, other than income taxes	**8**	9	**25**	26
Net other operating (income) loss (Note 6)	**(11)**	47	**(48)**	26
Operating income (loss)	**177**	(409)	**498**	(264)
Equity income	**1**	1	**5**	5
Finance lease income	**4**	6	**15**	19
Net interest expense (Note 7)	**(66)**	(63)	**(195)**	(186)
Foreign exchange gain	**6**	1	**17**	22
Gain on the sale of assets and other (Note 14)	**4**	23	**6**	56
Earnings (loss) before income taxes	**126**	(441)	**346**	(348)
Income tax expense (recovery) (Note 8)	**30**	(22)	**103**	42
Net earnings (loss)	**96**	(419)	**243**	(390)
Net earnings (loss) attributable to:				
TransAlta shareholders	**72**	(446)	**188**	(478)
Non-controlling interests (Note 9)	**24**	27	**55**	88
	96	(419)	**243**	(390)
Net earnings (loss) attributable to TransAlta shareholders	**72**	(446)	**188**	(478)
Preferred share dividends (Note 21)	**11**	10	**21**	20
Net earnings (loss) attributable to common shareholders	**61**	(456)	**167**	(498)
Weighted average number of common shares outstanding in the period (millions)	**271**	271	**271**	271
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.23**	(1.68)	**0.62**	(1.84)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2022**	2021	**2022**	2021
Net earnings (loss)	**96**	(419)	**243**	(390)
Other comprehensive income (loss)				
Net actuarial gains on defined benefit plans, net of tax[1]	**—**	2	**36**	40
Losses on derivatives designated as cash flow hedges, net of tax	**—**	—	**—**	(1)
Fair value losses on investments, net of tax (Note 13)	**(1)**	—	**(1)**	—
Total items that will not be reclassified subsequently to net earnings (loss)	**(1)**	2	**35**	39
Gains (losses) on translating net assets of foreign operations, net of tax	**24**	17	**18**	(20)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**(25)**	(11)	**(28)**	3
Losses on derivatives designated as cash flow hedges, net of tax[3]	**(100)**	(107)	**(251)**	(238)
Reclassification of losses (gains) on derivatives designated as cash flow hedges to net earnings (loss), net of tax[4]	**39**	19	**21**	(7)
Total items that will be reclassified subsequently to net loss	**(62)**	(82)	**(240)**	(262)
Other comprehensive loss	**(63)**	(80)	**(205)**	(223)
Total comprehensive income (loss)	**33**	(499)	**38**	(613)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**—**	(533)	**44**	(670)
Non-controlling interests (Note 9)	**33**	34	**(6)**	57
	33	(499)	**38**	(613)

(1) Net of income tax expense of nil and $11 million for the three and nine months ended Sept. 30, 2022 (Sept. 30, 2021 — $1 million and $12 million expense).
(2) Net of income tax recovery of $3 million and $4 million for the three and nine months ended Sept. 30, 2022 (Sept. 30, 2021 — nil for both periods).
(3) Net of income tax recovery of $29 million and $72 million for the three and nine months ended Sept. 30, 2022 (Sept. 30, 2021 — $29 million and $65 million recovery).
(4) Net of reclassification of income tax recovery of $10 million and $5 million for the three and nine months ended Sept. 30, 2022 (Sept. 30, 2021 — recovery of $5 million and expense of $2 million).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2022**	Dec. 31, 2021
Current assets		
Cash and cash equivalents	**816**	947
Restricted cash (Note 18)	**65**	70
Trade and other receivables (Note 10)	**1,327**	651
Prepaid expenses	**51**	29
Risk management assets (Note 11 and 12)	**755**	308
Inventory	**171**	167
Assets held for sale	**31**	25
	3,216	2,197
Non-current assets		
Investments (Note 13)	**125**	105
Long-term portion of finance lease receivables	**143**	185
Risk management assets (Note 11 and 12)	**226**	399
Property, plant and equipment (Note 14)		
Cost	**13,609**	13,389
Accumulated depreciation	**(8,315)**	(8,069)
	5,294	5,320
Right-of-use assets	**96**	95
Intangible assets (Note 15)	**257**	256
Goodwill	**465**	463
Deferred income tax assets	**60**	64
Other assets (Note 16)	**163**	142
Total assets	**10,045**	9,226
Current liabilities		
Accounts payable and accrued liabilities (Note 12)	**1,279**	689
Current portion of decommissioning and other provisions (Note 17)	**49**	48
Risk management liabilities (Note 11 and 12)	**854**	261
Current portion of contract liabilities (Note 22)	**6**	19
Income taxes payable	**11**	8
Dividends payable (Note 20 and 21)	**39**	62
Current portion of long-term debt and lease liabilities (Note 18)	**722**	844
	2,960	1,931
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 18)	**2,487**	2,423
Exchangeable securities	**738**	735
Decommissioning and other provisions (Note 17)	**651**	779
Deferred income tax liabilities	**349**	354
Risk management liabilities (Note 11 and 12)	**247**	145
Contract liabilities	**12**	13
Defined benefit obligation and other long-term liabilities (Note 19)	**184**	253
Total liabilities	**7,628**	6,633
Equity		
Common shares (Note 20)	**2,879**	2,901
Preferred shares (Note 21)	**942**	942
Contributed surplus	**33**	46
Deficit	**(2,318)**	(2,453)
Accumulated other comprehensive income	**2**	146
Equity attributable to shareholders	**1,538**	1,582
Non-controlling interest (Note 9)	**879**	1,011
Total equity	**2,417**	2,593
Total liabilities and equity	**10,045**	9,226

Commitments and contingencies (Note 22)
See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited **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 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	**—**	**—**	**—**	**(27)**	**—**	**(27)**	**—**	**(27)**
Preferred share dividends	**—**	**—**	**—**	**(21)**	**—**	**(21)**	**—**	**(21)**
Shares purchased under normal course issuer bid ("NCIB") program (Note 20)	**(29)**	**—**	**—**	**(5)**	**—**	**(34)**	**—**	**(34)**
Effect of share-based payment plans	**7**	**—**	**(13)**	**—**	**—**	**(6)**	**—**	**(6)**
Distributions paid and payable, to non-controlling interests (Note 9)	**—**	**—**	**—**	**—**	**—**	**—**	**(126)**	**(126)**
Balance, Sept. 30, 2022	**2,879**	**942**	**33**	**(2,318)**	**2**	**1,538**	**879**	**2,417**

9 months ended Sept. 30, 2021	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net loss	—	—	—	(478)	—	(478)	88	(390)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(17)	(17)	—	(17)
Net gain (losses) on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(247)	(247)	1	(246)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	40	40	—	40
Intercompany FVOCI investments	—	—	—	—	32	32	(32)	—
Total comprehensive income (loss)	—	—	—	(478)	(192)	(670)	57	(613)
Common share dividends	—	—	—	(37)	—	(37)	—	(37)
Preferred share dividends	—	—	—	(20)	—	(20)	—	(20)
Effect of share-based payment plans	5	—	(1)	—	—	4	—	4
Distributions paid and payable, to non-controlling interests (Note 9)	—	—	—	—	—	—	(117)	(117)
Balance, Sept. 30, 2021	2,901	942	37	(2,361)	110	1,629	1,024	2,653

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	**2022**	2021	**2022**	2021
Operating activities				
Net earnings (loss)	**96**	(419)	**243**	(390)
Depreciation and amortization (Note 14 and 23)	**179**	197	**411**	574
Gain on sale of assets and other (Note 14)	**(4)**	(23)	**(5)**	(56)
Accretion of provisions (Note 7)	**16**	9	**35**	23
Decommissioning and restoration costs settled (Note 17)	**(9)**	(5)	**(23)**	(13)
Deferred income tax (recovery) expense (Note 8)	**20**	(46)	**68**	(17)
Unrealized loss (gain) from risk management activities	**151**	(67)	**111**	(100)
Unrealized foreign exchange loss (gain)	**6**	1	**7**	(24)
Provisions and contract liabilities	**(8)**	3	**(4)**	(19)
Asset impairment charges (Note 5)	**70**	575	**4**	620
Equity income, net of distributions from investments	**—**	(2)	**(2)**	(3)
Other non-cash items	**(37)**	9	**(67)**	30
Cash flow from operations before changes in working capital	**480**	232	**778**	625
Change in non-cash operating working capital balances	**(276)**	378	**(252)**	322
Cash flow from operating activities	**204**	610	**526**	947
Investing activities				
Additions to property, plant and equipment (Note 14)	**(280)**	(127)	**(481)**	(344)
Additions to intangible assets (Note 15)	**(4)**	(1)	**(27)**	(4)
Restricted cash (Note 18)	**(22)**	(20)	**3**	(5)
Repayments in loan receivable (Note 16)	**4**	2	**14**	—
Proceeds on sale of Pioneer Pipeline (Note 14)	**—**	—	**—**	128
Proceeds on sale of property, plant and equipment	**10**	33	**12**	37
Realized gains (losses) on financial instruments	**9**	(1)	**8**	(4)
Decrease in finance lease receivable	**12**	10	**34**	30
Other	**6**	4	**13**	(14)
Change in non-cash investing working capital balances	**90**	19	**83**	(26)
Cash flow used in investing activities	**(175)**	(81)	**(341)**	(202)
Financing activities				
Net decrease in borrowings under credit facilities	**—**	—	**—**	(114)
Repayment of long-term debt	**(21)**	(18)	**(80)**	(63)
Dividends paid on common shares (Note 20)	**(14)**	(13)	**(41)**	(37)
Dividends paid on preferred shares (Note 21)	**(11)**	(9)	**(31)**	(29)
Repurchase of common shares under NCIB (Note 20)	**(10)**	—	**(28)**	(4)
Net proceeds on issuance of common shares	**—**	—	**1**	8
Realized losses on financial instruments	**—**	(1)	**—**	—
Distributions paid to subsidiaries' non-controlling interests (Note 9)	**(54)**	(50)	**(126)**	(117)
Decrease in lease liabilities	**(2)**	(2)	**(6)**	(6)
Financing fees and other	**(2)**	1	**(4)**	(2)
Change in non-cash financing working capital balances	**—**	1	**—**	—
Cash flow used in financing activities	**(114)**	(91)	**(315)**	(364)
Cash flow (used in) from operating, investing and financing activities	**(85)**	438	**(130)**	381
Effect of translation on foreign currency cash	**3**	—	**(1)**	(4)
(Decrease) increase in cash and cash equivalents	**(82)**	438	**(131)**	377
Cash and cash equivalents, beginning of period	**898**	642	**947**	703
Cash and cash equivalents, end of period	**816**	1,080	**816**	1,080
Cash taxes paid	**10**	13	**53**	40
Cash interest paid	**52**	49	**159**	161

See accompanying notes.

Notes to 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. Its head office is located in Calgary, Alberta.

Operating Segments

In 2021, the Company realigned its current operating segments to reflect a change in how TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM") reviews financial information in order to allocate resources and assess performance. The primary changes were the elimination of the Alberta Thermal and the Centralia segments, and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas have been included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes were made to the Hydro and Wind and Solar segments. This change better aligns with the Company's long-term strategy and reflects its Clean Electricity Growth Plan. Refer to Note 23 for further details.

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 its 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. 7, 2022.

C. Significant Accounting Judgments 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, discount 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, 2022, the global economy continued to recover from the COVID-19 pandemic. The Russia-Ukraine conflict has set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. Energy prices have strengthened due to elevated uncertainty of global oil and natural gas supply given the war in Ukraine. Recent inflationary and supply chain dynamics coupled with rising interest rates and volatility in foreign exchange rates have created an environment that requires close monitoring. Estimates to the extent to which the geopolitical events may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods are also subject to significant uncertainty. Uncertainty related to COVID-19, geopolitical events and Consumer Price Index ("CPI") inflation have been considered in the Company's estimates as at and for the period ended Sept. 30, 2022.

During the three and nine months ended Sept. 30, 2022, there were changes in estimates relating to asset useful lives and depreciation (Note 14), decommissioning and other provisions (Note 17) and defined benefit obligations (Note 19).

Refer to Note 2(P) of the Company’s 2021 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, 2021, except for the adoption of new standards effective as of Jan. 1, 2022, the early adoption of standards and interpretations or amendments that have been issued but are not yet effective.

A. Current Accounting Policy Changes

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the International Accounting Standards Board ("IASB") issued Onerous Contracts — Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted in the adoption of the amendments on Jan. 1, 2022.

B. Future Accounting Policy Changes

Please refer to Note 3 of the audited annual 2021 consolidated financial statements for the future accounting policies impacting the Company. In the three and nine months ended Sept. 30, 2022, no additional future accounting policy changes impacting the Company were identified.

C. Comparative Figures

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

3. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of physical 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, 2022	**Hydro**	**Wind and Solar**	**Gas[(1)]**	**Energy Transition[(2)]**	**Energy Marketing**	**Corporate and Other**	**Total**
Revenues from contracts with customers							
Power and other	**11**	**37**	**124**	**—**	**—**	**—**	**172**
Environmental attributes	**—**	**3**	**—**	**—**	**—**	**—**	**3**
Revenue from contracts with customers	**11**	**40**	**124**	**—**	**—**	**—**	**175**
Revenue from leases[(3)]	**—**	**—**	**12**	**—**	**—**	**—**	**12**
Revenue from derivatives and other trading activities[(4)]	**—**	**(49)**	**(286)**	**60**	**54**	**1**	**(220)**
Revenue from merchant sales	**252**	**17**	**518**	**171**	**—**	**—**	**958**
Other	**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) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Significant volatility and pricing in commodity markets resulted in higher than normal movements in derivative positions.

3 months ended Sept. 30, 2021	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	8	37	103	10	—	—	158
Environmental attributes	—	14	—	—	—	—	14
Revenue from contracts with customers	8	51	103	10	—	—	172
Revenue from leases[(3)]	—	—	4	—	—	—	4
Revenue from derivatives and other trading activities[(4)]	—	(18)	—	74	86	1	143
Revenue from merchant sales	86	15	275	147	—	—	523
Other	2	4	2	—	—	—	8
Total revenue	96	52	384	231	86	1	850
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	14	(1)	10	—	—	23
Over time	8	37	104	—	—	—	149
Total revenue from contracts with customers	8	51	103	10	—	—	172

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with the current period.

9 months ended Sept. 30, 2022	**Hydro**	**Wind and Solar**	**Gas(1)**	**Energy Transition(2)**	**Energy Marketing**	**Corporate and Other**	**Total**
Revenues from contracts with customers							
Power and other	**29**	**155**	**340**	**6**	**—**	**—**	**530**
Environmental attributes	**1**	**33**	**—**	**—**	**—**	**—**	**34**
Revenue from contracts with customers	**30**	**188**	**340**	**6**	**—**	**—**	**564**
Revenue from leases(3)	**—**	**—**	**20**	**—**	**—**	**—**	**20**
Revenue from derivatives and other trading activities(4)	**—**	**(69)**	**(359)**	**174**	**116**	**3**	**(135)**
Revenue from merchant sales	**411**	**61**	**925**	**253**	**—**	**—**	**1,650**
Other	**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) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Significant volatility and pricing in commodity markets resulted in higher than normal movements in derivative positions.

9 months ended Sept. 30, 2021	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	21	149	275	20	—	—	465
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	21	172	275	20	—	—	488
Revenue from leases(3)	—	—	14	—	—	—	14
Revenue from derivatives and other trading activities(4)	—	(15)	(57)	137	185	6	256
Revenue from merchant sales	271	44	699	314	—	—	1,328
Other(5)	7	12	6	—	—	—	25
Total revenue	299	213	937	471	185	6	2,111
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	23	1	19	—	—	43
Over time	21	149	274	1	—	—	445
Total revenue from contracts with customers	21	172	275	20	—	—	488

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with the current period.
(5) Includes government incentives and other miscellaneous revenue.

B. Changes to Revenue Contracts

Wind and Solar

On Aug. 23, 2022, the Company announced that it was awarded a capacity contract with the Ontario Independent Electricity System Operator (the "IESO") for the Melancthon 1 wind facility, which will extend the period of contracted revenues to April 30, 2031. The wind facility's existing PPA with the IESO ends on March 3, 2026.

On June 2, 2022, TransAlta Renewables Inc., a subsidiary of the Company ("TransAlta Renewables") announced that it amended and extended its current power purchase agreements with New Brunswick Power Corporation ("NB Power") in respect of each of the Kent Hills 1, 2 and 3 wind facilities, representing total generating capacity of 167 MW. The amending agreements provide for a blend-and-extend of the PPAs providing NB Power with an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033 and the extension of the original contract term for an additional 10-year period through to December 2045.

Refer to Notes 14, 16 and 18 for further discussion related to the Kent Hills wind facilities.

Gas

On Aug. 23, 2022, the Company announced that it was awarded a capacity contract with the IESO for the Sarnia cogeneration facility, which will extend the period of contracted revenues to April 30, 2031. The current IESO contract ends on Dec. 31, 2025. The Company expects gross margin from the Sarnia cogeneration facility to be reduced by approximately 30 per cent per year as a result of the IESO price cap under the new contract.

During the second quarter of 2022, the Company executed contract extensions for the supply of electricity with three of its industrial customers and for the supply of steam for one of these customers, at the Sarnia cogeneration facility. These agreements extend the delivery term from Dec. 31, 2022 to April 30, 2031 in one case and to Dec. 31, 2032, for the other two.

4. Expenses by Nature

A. 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**			
	2022		2021		**2022**		2021	
	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	**152**	**—**	80	—	**409**	**—**	200	—
Coal fuel costs(1)	**48**	**—**	53	—	**96**	**—**	123	—
Royalty, land lease and other direct costs	**6**	**—**	4	—	**18**	**—**	14	—
Purchased power(2)	**141**	**—**	108	—	**290**	**—**	246	—
Mine depreciation(3)	**—**	**—**	74	—	**—**	**—**	179	—
Salaries and benefits	**1**	**66**	9	67	**4**	**180**	26	174
Other operating expenses(2)(4)	**—**	**69**	—	63	**—**	**184**	—	207
Total	**348**	**135**	328	130	**817**	**364**	788	381

(1) During the three and nine months ended Sept. 30, 2021, $5 million and $16 million, respectively, was included in coal fuel costs related to the impairment of coal inventory recorded during 2021.
(2) During the three and nine months ended Sept. 30, 2021, $1 million and $6 million, respectively, related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(3) During the three and nine months ended Sept. 30, 2021, $19 million and $48 million, respectively, was included in mine depreciation, related to the impairment of mine depreciation recorded during 2021.
(4) During the three and nine months ended Sept. 30, 2021, OM&A costs included a writedown of $5 million and $30 million, respectively, for parts and material inventory related to the Highvale mine and coal operations at our gas converted facilities.

B. Carbon Compliance

During the nine months ended Sept. 30, 2022, the Company utilized 1,169,333 emission credits with a carrying value of $35 million to settle the 2021 carbon compliance obligation of $47 million. The difference of $12 million has been recognized as a reduction in the Company's carbon compliance costs in the period.

As at Sept. 30, 2022, the Company currently holds 1,017,980 emission credits in inventory purchased externally with a recorded book value of $34 million (Dec. 31, 2021 — 2,033,752 emission credits with a recorded book value of $55 million). The Company also has approximately 1,922,972 of internally generated eligible emission credits with no recorded book value (Dec. 31, 2021 — 1,922,973). In addition, the Company holds approximately 1,750,000 eligible emission credits generated from assets formerly subject to the Hydro Power Purchase Arrangement ("Hydro PPA") during the period 2018-2020, which also have no recorded book value. Refer to Note 22 for further details.

5. Asset Impairment Charges

The Company has determined that certain assets and/or facilities will be grouped together to form a cash generating unit ("CGU") where requirements are met for the purposes of impairment testing. Property, Plant and Equipment ("PP&E") and goodwill have been allocated to each of the CGUs or groups of CGUs in a segment that are expected to benefit from the synergies of the business combination in which the goodwill arose, to determine the carrying amount.

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use and fair value less costs of disposal) for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Company's discount rates, long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2072.

During the period, the Company recognized the following asset impairment charges (reversals):

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Wind and Solar	**14**	10	**35**	10
Hydro	**15**	9	**21**	9
Energy Transition Facilities	**—**	509	**—**	519
Corporate	**—**	—	**—**	27
Changes in decommissioning and restoration provisions on retired assets	**41**	44	**(52)**	38
Intangible asset impairment - Coal Rights(1)	**—**	3	**—**	17
Asset impairment charges	**70**	575	**4**	620

(1) Impaired to nil in 2021, as no future coal will be extracted from this area of the mine.

Wind and Solar

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, three wind facilities were impaired primarily as a result of an increase in discount rates. During the third quarter, 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.

During the third quarter of 2021, the Company recorded an impairment charge of $8 million for a wind asset as result of an increase in estimated decommissioning costs after the review of a recent engineering study. The resulting fair value measurement less cost of disposal is categorized as a Level III fair value measurement and the Company adjusted the expected value down to $65 million as at Sept. 30, 2021 using discount rates of 5 per cent. The key assumptions impacting the determination of fair value are electricity production, sales prices and cost inputs, which are subject to measurement uncertainty.

As at Sept. 30, 2021, the Company recognized an impairment charge of $2 million related to the Kent Hills Wind LP tower failure.

Hydro

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, an impairment of $6 million was recorded on one of the hydro facilities primarily from an increase in discount rates. During the third quarter, 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.

During the third quarter of 2021, the Company recorded an impairment charge of $9 million in the Hydro segment on the balance of project development costs at one of the hydro facilities as there was uncertainty on timing of when the project will proceed.

The calculation of fair value less cost of disposal for all of the above facilities is most sensitive to the following assumptions:

	Location of assets	2022 Contract and Merchant discount rates	Prior period Contract and Merchant discount rates[1]
Wind and Solar	Canada	6.4 and 7.1 per cent	5.0 and 5.0 per cent
	United States ("US")	6.5 and 7.3 per cent	5.1 and 5.1 per cent
Hydro	Canada	5.9 and 6.4 per cent	3.6 and 4.9 per cent

(1) Prior period discount rates were related to the most recent detailed valuation performed for the Wind and Solar segment in third quarter of 2021, and for the Hydro segment in the third quarter of 2019.

Energy Transition

During the third quarter of 2021, the Company recognized asset impairments charges in the Alberta Thermal segment as a result of the decision to suspend the Sundance Unit 5 repowering project of $190 million and planned retirements of Keephills Unit 1 of $78 million and Sundance Unit 4 of $56 million. Keephills Unit 1 and Sundance Unit 4 impairment assessments were based on the estimated salvage values of these units which were in excess of the expected economic benefits from these units. For the Sundance Unit 5 repowering project, impairment assessments were based on the estimated recoverable amount of estimated fair value less costs of disposal of reselling the equipment for assets under construction and estimated salvage value for the balance of the costs. The fair value measurement for assets under construction is categorized as a Level III fair value measurement. The total remaining estimated recoverable amount and salvage values for the Sundance Unit 5 repowering project was $33 million as at Sept. 30, 2021. Discounting did not have a material impact to these asset impairments. These asset retirement and project suspension decisions were based on the Company's assessment of future market conditions, the age and condition of in-service units and TransAlta's strategic focus toward customer-centred renewable energy solutions.

During the third quarter of 2021, with the shut down of the Highvale Mine at the end of 2021, it was determined that the estimated salvage value exceeded the economic benefit to the Alberta Merchant CGU. The asset was removed from the Alberta Merchant CGU for impairment purposes and was assessed for impairment as an individual asset which resulted in the recognized impairment charge of $185 million within the Energy Transition segment, with the asset being written down to salvage value.

Corporate
Energy Transfer Canada, formerly SemCAMS Midstream ULC, purported to terminate the agreements related to the development and construction of the Kaybob Cogeneration Project. As a result, during the first quarter of 2021, the Company recorded an impairment of $27 million in the Corporate segment as this facility was not yet operational. The recoverable amount was based on estimated fair value less costs of disposal of reselling the equipment purchased to date.

Changes in Decommissioning and Restoration Provisions on Retired Assets
During the third quarter of 2022, the Company accelerated the expected timing on decommissioning and restoration for certain retired gas assets. This resulted in an increase in the decommissioning and restoration provision with a $50 million impairment recorded in the quarter. In addition, for the three and nine months ended Sept. 30, 2022, the decommissioning and restoration provisions relating to retired assets have decreased due to an increase in discount rates, resulting in an impairment reversal of $9 million and $102 million, respectively. Refer to Note 14 and 17 for further details.

6. Net Other Operating (Income) Loss
Net other operating (income) loss includes the following:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Alberta Off-Coal Agreement	**(10)**	(10)	**(30)**	(30)
Liquidated damages recoverable	**(1)**	—	**(11)**	—
Insurance recoveries	**—**	—	**(7)**	(1)
Supplier settlements	**—**	43	**—**	43
Highvale Mine onerous contract provision	**—**	14	**—**	14
Net other operating (income) loss	**(11)**	47	**(48)**	26

Alberta Off-Coal Agreement
The Company receives payments from the Government of Alberta for the cessation of coal-fired emissions on or before Dec. 31, 2030. Under the terms of the agreement, the Company receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net of the non-controlling interest related to Sheerness facility), which commenced Jan. 1, 2017 and will terminate at the end of 2030. Refer to Note 9 in the 2021 audited annual consolidated financial statements for further details.

Liquidated Damages Recoverable
During the three and nine months ended Sept. 30, 2022, the Company recorded $1 million and $11 million, respectively, related to requirements to be met by the contractor on turbine availability at the Windrise wind facility.

Insurance Recoveries
During the nine months ended Sept. 30, 2022, the Company received insurance proceeds of $7 million related to the replacement costs for the single collapsed tower at the Kent Hills wind facilities.

Supplier Settlements
During the third quarter of 2021, $27 million was expensed for amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project, $10 million (US$8 million) deferred asset was expensed as it was not likely that the Company would incur sufficient capital or operating expenditures to utilize the remaining credit and $6 million was expensed for amounts due to contractors for not proceeding with the construction of equipment for Keephills Unit 1 during the third quarter of 2021.

Highvale Mine Onerous Contract Provision
During the third quarter of 2021, an onerous contract provision for future royalty payments of $14 million was recognized as a result of a decision to accelerate the plans to shut down the Highvale Mine.

7. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Interest on debt	**42**	41	**123**	121
Interest on exchangeable debentures	**7**	8	**22**	22
Interest on exchangeable preferred shares	**7**	7	**21**	21
Interest income	**(7)**	(2)	**(14)**	(8)
Capitalized interest (Note 14)	**(4)**	(5)	**(8)**	(13)
Interest on lease liabilities	**1**	1	**4**	5
Credit facility fees, bank charges and other interest	**5**	4	**16**	14
Tax shield on tax equity financing	**(1)**	—	**(4)**	1
Accretion of provisions	**16**	9	**35**	23
Net interest expense	**66**	63	**195**	186

During the three and nine months ended Sept. 30, 2022, the Company capitalized interest at a weighted average rate of 6.1 per cent (Sept. 30, 2021 - 6.0 per cent).

On Nov. 7, 2022, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.764 per cent per share payable on Nov. 30, 2022. The Exchangeable Preferred Shares are considered debt for accounting purposes and, as such, dividends are reported as interest expense.

8. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Current income tax expense	**10**	24	**35**	59
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**20**	(125)	**168**	(144)
Deferred income tax expense (recovery) related to temporary difference on investment in subsidiary	**—**	2	**(7)**	2
Deferred income tax expense (recovery) arising from the writedown (reversal of write-down) of deferred income tax assets(1)	**—**	77	**(93)**	125
Income tax expense (recovery)	**30**	(22)	**103**	42

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Current income tax expense	**10**	24	**35**	59
Deferred income tax expense (recovery)	**20**	(46)	**68**	(17)
Income tax expense (recovery)	**30**	(22)	**103**	42

(1) During the nine months ended Sept. 30, 2022, the Company recorded a write-down reversal of deferred tax assets $93 million mainly related to tax benefits of losses associated with the Company's directly owned US and Canadian operations. The write-down of deferred income tax assets related to US and Canadian operations arose as it is not considered probable that sufficient future taxable income will be available to utilize the underlying tax losses. The Company evaluates at each period end whether it is probable that sufficient future taxable income would be available to utilize the underlying tax losses.

9. Non-Controlling Interests

The Company's subsidiaries with significant non-controlling interests are 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	
	2022	2021	**2022**	2021
Net earnings				
TransAlta Cogeneration L.P.	**32**	17	**45**	48
TransAlta Renewables	**(8)**	10	**10**	40
	24	27	**55**	88
Total comprehensive income (loss)				
TransAlta Cogeneration L.P.	**32**	17	**45**	48
TransAlta Renewables	**1**	17	**(51)**	9
	33	34	**(6)**	57
Cash distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**29**	25	**51**	42
TransAlta Renewables	**25**	25	**75**	75
	54	50	**126**	117

As at	Sept. 30, 2022	Dec. 31, 2021
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**135**	142
TransAlta Renewables	**744**	869
	879	1,011
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

10. Trade and Other Receivables

As at	Sept. 30, 2022	Dec. 31, 2021
Trade accounts receivable	**933**	499
Collateral paid (Note 12)	**315**	55
Current portion of finance lease receivable	**47**	40
Loan receivable (Note 16)	**9**	55
Income taxes receivable	**23**	2
Trade and other receivables	**1,327**	651

11. Financial Instruments

A. Financial Assets and Liabilities – Measurement

Financial assets and financial liabilities are measured on an ongoing basis at 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.

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, refer to Note 15 of the 2021 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 businesses 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, 2022, are as follows: Level I — $76 million net asset (Dec. 31, 2021 — $12 million net asset), Level II — $350 million net asset (Dec. 31, 2021 — $122 million net asset) and Level III — $611 million net liability (Dec. 31, 2021 — $159 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2022, are primarily attributable to volatility in market prices across multiple markets on both existing contracts and new contracts as well as contract settlements.

The following tables summarize 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, 2022 and 2021, respectively:

	9 months ended Sept. 30, 2022			9 months ended Sept. 30, 2021		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**285**	**(126)**	**159**	573	9	582
Changes attributable to:						
Market price changes on existing contracts	**(346)**	**(371)**	**(717)**	(249)	(100)	(349)
Market price changes on new contracts	**—**	**(114)**	**(114)**	—	(123)	(123)
Contracts settled	**(37)**	**82**	**45**	(83)	(10)	(93)
Change in foreign exchange rates	**20**	**(6)**	**14**	(4)	—	(4)
Transfers into (out of) Level III	**—**	**2**	**2**	—	—	—
Net risk management assets (liabilities) at end of period	**(78)**	**(533)**	**(611)**	237	(224)	13
Additional Level III information:						
Losses recognized in other comprehensive income	**(326)**	**—**	**(326)**	(253)	—	(253)
Total gains (losses) included in earnings before income taxes	**37**	**(491)**	**(454)**	83	(223)	(140)
Unrealized losses included in earnings before income taxes relating to net liabilities held at period end	**—**	**(409)**	**(409)**	—	(233)	(233)

As of Sept. 30, 2022, the total Level III risk management asset balance was nil (Dec. 31, 2021 — $305 million) and Level III risk management liability balance was $611 million (Dec. 31, 2021 — $146 million). The following information on risk management contracts or groups of risk management contracts that are included in Level III measurements, 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, 2022**	
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	**+19**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$31
	-120			
Coal transportation – US	**+14**	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or increase of US$31
			Volatility	80% to 120%
	-11		Rail rate escalation	zero to 10%
Full requirements – Eastern US	**+4**	Monte Carlo	Volume	95% to 105%
	-25		Cost of supply	US$(1) to US$3 per MWh
Long-term wind energy sale – Eastern US	**+20**	Long-term price forecast	Illiquid future power prices (per MWh)	Price increase or decrease of US$6
			Illiquid future REC prices (per unit)	Price decrease of US$2 or increase of US$1
	-15		Wind discounts	zero to 5%
Long-term wind energy sale – Canada	**+68**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$75 or increase of C$4
	-16		Wind discounts	14% decrease or 5% increase
Long-term wind energy sale - Central US	**+57**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$4 or increase of US$5
	-21		Wind discounts	3% decrease or 7% increase
Others	**+8**			
	-8			

As at		Dec. 31, 2021		
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	+22 -145	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or increase of US$20
Coal transportation – US	+3 -18	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or increase of US$20 80% to 120% zero to 4%
Full requirements – Eastern US	+9 -9	Monte Carlo	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+17 -16	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price decrease of US$3 or increase of US$2
Long-term wind energy sale – Canada	+21 -11	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of C$24 or increase of C$5 5% decrease or 5% increase
Long-term wind energy sale - Central US	+27 -15	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of US$2 or increase of US$3 3% decrease or 3% increase
Others	+6 -6			

Contracts that are entered into with customers for the off-take of energy and other outputs from Company owned facilities may not be eligible to be accounted for as own use contracts with customers and may either be classified and accounted for as derivatives or contain embedded derivatives. Conditions that result in derivative classification include, for example: net financial settlement of the contract; lack of physical delivery requirements; or, the contract is readily convertible to cash. When a contract with a customer is classified and accounted for as a derivative, the contract is recognized within risk management assets (liabilities) at fair value and subsequent changes in fair value of the contract are recognized in revenues as revenue from derivatives and other trading activities, unless hedge designation is available and made.

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 strengthened from Dec. 31, 2021 to Sept. 30, 2022, resulting in a decrease in the base fair value and an increase in the sensitivity values by approximately $6 million and $8 million, respectively.

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 and independent system operator costs.

iv. Long-Term Wind Energy Sale – Eastern US
In relation to the Big Level wind facility, the Company has a long-term contract for differences whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. 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
In relation to the Garden Plain wind project, the Company has entered into two virtual PPAs whereby the Company receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. Both contracts commence on commercial operation of the facility, which is expected by the the end of 2022 and extend for a weighted average of approximately 17 years.

In addition to the virtual PPA contracts, the Company has entered into a bridge contract that runs 16 months from Sept. 1, 2021 through Dec. 31, 2022, which automatically extends at the virtual PPA price should the commencement of commercial operations occur after Dec. 31, 2022.

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

vi. Long-Term Wind Energy Sale – Central US
The Company has entered into two long-term virtual PPAs for the off take of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects (collectively, the "White Rock Wind projects") to be located in Caddo County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh. The contracts commence on commercial operation of the facilities, which is expected within the second half of 2023 and extend for more than 10 years past that date.

On April 5, 2022, the Company entered into a long-term virtual PPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind project ("Horizon Hill wind project") to be located in Logan County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh. The contract commences on commercial operation of the facility, which is expected within the second half of 2023.

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

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

Other risk management assets and liabilities with a total net asset fair value of $65 million as at Sept. 30, 2022 (Dec. 31, 2021 – $8 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the nine months ended Sept. 30, 2022, are primarily attributable to favourable impacts of interest rate increases on existing contracts and favourable foreign exchange rates on new contracts entered into during 2022.

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, 2022	**—**	**718**	**—**	**718**	**738**
Long-term debt - Sept. 30, 2022	**—**	**2,790**	**—**	**2,790**	**3,105**
Exchangeable securities - Dec. 31, 2021	—	770	—	770	735
Long-term debt - Dec. 31, 2021	—	3,272	—	3,272	3,167

(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 paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable and the finance lease receivables approximate the carrying amounts and the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 11 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. 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	
	2022	2021
Unamortized net loss at beginning of the period	**(131)**	(33)
New inception gains (losses)	**(40)**	15
Change in foreign exchange rates	**(11)**	—
Amortization recorded in net earnings during the period	**(21)**	(6)
Unamortized net loss at end of the period	**(203)**	(24)

12. 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 (loss) 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 16 of the 2021 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, 2022	**Cash flow hedges**	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**(110)**	**(54)**	**(164)**
Long-term	**32**	**(53)**	**(21)**
Net commodity risk management liabilities	**(78)**	**(107)**	**(185)**
Other			
Current	**59**	**6**	**65**
Long-term	**—**	**—**	**—**
Net other risk management assets	**59**	**6**	**65**
Total net risk management liabilities	**(19)**	**(101)**	**(120)**

As at Dec. 31, 2021	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	33	12	45
Long-term	252	(4)	248
Net commodity risk management assets	285	8	293
Other			
Current	3	(1)	2
Long-term	—	6	6
Net other risk management assets	3	5	8
Total net risk management assets	288	13	301

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 (loss) in the period that the price changes occur. VaR at Sept. 30, 2022, associated with the Company’s proprietary trading activities was $3 million (Dec. 31, 2021 — $2 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 by products, as considered appropriate. VaR at Sept. 30, 2022, associated with the Company's commodity derivative instruments used in generation hedging activities was $34 million (Dec. 31, 2021 — $33 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 (loss) in the period in which the price change occurs. VaR at Sept. 30, 2022, associated with these transactions was $43 million (Dec. 31, 2021 — $51 million), of which $21 million related to virtual PPAs (Dec. 31, 2021 — $18 million).

iii. Interest Rate Risk
Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact the Company's borrowing costs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Company's credit facility, Term Facility ("Term Facility") and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 3 per cent of the Company's debt as at Sept. 30, 2022 (Dec. 31, 2021 - 3 per cent). The Poplar Creek non-recourse bond face value as at Sept. 30, 2022 was $98 million (Dec. 31, 2021 — $104 million), with interest expense based upon the three-month Canadian Dollar Offered Rate, which will be discontinued in 2024.

During the third quarter of 2022, the interest rate swap agreements with a notional amount of US$150 million referencing the three-month LIBOR were replaced with swap agreements referencing the Secured Overnight Financing Rate ("SOFR"). Existing interest rate swap agreements with a notional amount of US$150 million reference the US Treasury Bond yield. The maturity dates on all swap agreements have been extended.

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, 2022:

	Investment grade (Per cent)	**Non-investment grade** (Per cent)	**Total** (Per cent)	**Total amount**
Trade and other receivables[1,2]	86	14	100	**1,318**
Long-term finance lease receivables	100	—	100	**143**
Risk management assets[1]	81	19	100	**981**
Loan receivable[2]	—	100	100	**41**
Total				**2,483**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $41 million loan receivable included within Other Assets with a counterparty that has no external credit rating. The current portion of $9 million was excluded from trade and other receivables as it is included in loan receivable in the table above.

The Company did not have significant expected credit losses as at Sept. 30, 2022.

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, 2022, was $98 million (Dec. 31, 2021 — $37 million).

III. Liquidity Risk
The Company has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt maturity is scheduled for November 2022. Our highly diversified asset portfolio, by both fuel type and operating region, provide stability in cash flows and highlight the strength of our long-term contracted asset base.

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 as well as financial assets that are expected to generate cash inflows to meet cash outflows on financial liabilities, is as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Accounts payable and accrued liabilities	1,279	—	—	—	—	—	1,279
Long-term debt[1]	580	170	127	141	143	1,976	3,137
Exchangeable securities[2]	—	—	—	750	—	—	750
Commodity risk management (assets) liabilities	92	67	33	(43)	9	27	185
Other risk management (assets) liabilities	(79)	13	—	2	—	(1)	(65)
Lease liabilities[3]	(1)	(3)	4	4	4	96	104
Interest on long-term debt and lease liabilities[4]	47	133	128	120	113	830	1,371
Interest on exchangeable securities[2,4]	13	53	62	—	—	—	128
Dividends payable	39	—	—	—	—	—	39
Total	**1,970**	**433**	**354**	**974**	**269**	**2,928**	**6,928**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025.
(3) Lease liabilities includes a lease incentive of $4 million expected to be received in 2022 and $8 million in 2023.
(4) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

C. Collateral and Contingent Features in Derivative Instruments

I. Financial Assets Provided as Collateral

At Sept. 30, 2022, the Company provided $315 million (Dec. 31, 2021 – $55 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 in trade and other receivables in the Condensed Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Sept. 30, 2022, the Company held $395 million (Dec. 31, 2021 – $18 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.

As at Sept. 30, 2022, the Company had posted collateral of $600 million (Dec. 31, 2021 – $356 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, and result in no unsecured credit being available to the Company, may result in having to post an additional $545 million (Dec. 31, 2021 – $120 million) of collateral to the Company's counterparties.

13. Investments

The Company's investments include its 49% interest in the Skookumchuck wind facility and its 30% interest in EMG International LLC ("EMG") and the investments acquired in 2022, as discussed below:

Energy Impact Partners Investment ("EIP")

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in EIP's Deep Decarbonization Frontier Fund 1 (the “Frontier Fund”). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. During the second quarter of 2022, the Company made an initial investment of $7 million (US$6 million). The investment is accounted for at fair value through profit or loss.

Ekona Power Inc. ("Ekona")

On Feb. 1, 2022, the Company made an equity investment of $2 million in Ekona's Class B Preferred Shares. The investment will help support the commercialization of Ekona’s novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. The investment is accounted for at fair value through other comprehensive income.

14. Property, Plant and Equipment

Assets under construction

During the three and nine months ended Sept. 30, 2022, the Company had additions of $249 million and $440 million, respectively, mainly related to assets under construction for the White Rock wind projects, Garden Plain wind project, Horizon Hill wind project, Northern Goldfields solar project and other planned major maintenance.

In addition, the Company has begun its rehabilitation plan at the Kent Hills wind facilities. For the three and nine months ended Sept. 30, 2022, the Company has capitalized additions of $31 million and $41 million, respectively.

During the three and nine months ended Sept. 30, 2021, the Company had additions of $127 million and $344 million, respectively, mainly related to assets under construction for the coal-to-gas conversions, Windrise wind facility, the Garden Plain wind project, Sundance Unit 5 repowering project and other planned major maintenance expenditures. During the nine months ended Sept. 30, 2021, the Company completed the conversions of Keephills Unit 2, Sheerness Unit 1 and Sundance Unit 6 and the costs were transferred to gas generation.

Renewable Generation

During the first quarter of 2022, $16 million of costs, related to transmission infrastructure at the Windrise wind facility, were reclassified from PP&E to Other Assets and will be amortized to net earnings (loss) over the useful life of the Windrise wind facility. In accordance with the asset transfer agreement, the ownership of these assets must be transferred to the transmission line owner upon completion of construction of the transmission infrastructure.

Gas Generation

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. for the aggregate sale price of $255 million. The net cash proceeds to the Company from the sale of its 50 per cent interest, were approximately $128 million and the Company recognized a gain on sale of $31 million on the Condensed Consolidated Statements of Earnings. In addition, as part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated which resulted in a gain of $2 million.

Energy Transition

Keephills Unit 1 and Sundance Unit 5 were retired in 2021. Sundance Unit 4 was retired from service effective March 31, 2022.

Change in Estimate - Useful Lives
During the third quarter of 2022, the Company adjusted the useful lives of certain assets included in the Gas segment to reflect changes made based on the future operating expectations of the assets. This resulted in an increase of $64 million in depreciation expense that was recognized in the Condensed Consolidated Statement of Earnings in the third quarter of 2022.

Change in Estimate - Decommissioning provision
During the nine months ended 2022, the Corporation adjusted certain gas assets decommissioning and restoration provisions to reflect the potential timing to begin reclamation efforts. The Corporation's current best estimate of the decommissioning and restoration provision increased by $40 million.

In addition, during the nine months ended Sept. 30, 2022, the decommissioning and restoration provisions on operating assets have been updated to reflect an increase in discount rates, resulting in a decrease in the decommissioning and restoration provision and in the related assets in PP&E of $125 million.

Refer to Note 17 for further details.

15. Intangible Assets
The Company acquired a portfolio of wind development projects in the US in 2019. Upon moving forward with any of these projects, additional consideration may be payable on a project-by-project basis in the event a project achieves commercial operations prior to Dec. 31, 2025.

During the nine months ended Sept. 30, 2022, the Company recorded $16 million (Sept. 30, 2021 — nil) of contingent consideration relating to US wind development projects. Additionally, the Company reclassified development costs of $3 million from Other Assets to Intangible Assets comprised of initial acquisition costs.

16. Other Assets
Kent Hills LP Loan
Other Assets includes a $41 million (Dec. 31, 2021 - $55 million) unsecured loan related to an advancement by the Company's subsidiary, Kent Hills Wind LP ("KHLP"), of the net financing proceeds of the Kent Hills Wind Bond ("KH Bonds"), to its 17 per cent partner. On June 1, 2022, the loan receivable agreement was amended and its original maturity date of Oct. 2, 2022 was extended to October 2027, resulting in the classification of a portion of the loan receivable to non-current assets. The remaining terms of the original loan remain unchanged and it continues to bear interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until maturity. However, repayments may be required for amounts associated with foundation replacement capital expenditures as outlined in the amendment made to the KH Bonds. During the nine months ended Sept. 30, 2022, the Company received repayments of $14 million which were required as part of the waiver and amendment made to the KH Bonds. As at Sept. 30, 2022, $9 million (Dec. 31, 2021 - $55 million) was recorded as current and included in Trade and Other Receivables.

Windrise Prepaid
During the first quarter of 2022, $16 million of costs related to transmission infrastructure at the Windrise wind facility were reclassified from PP&E to Other Assets and will be amortized to net earnings (loss) over the useful life of the Windrise wind facility. Refer to Note 14 for further detail.

17. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Liabilities settled	**(23)**	**(11)**	**(34)**
Accretion	**35**	**—**	**35**
Transfers	**(2)**	**—**	**(2)**
Revisions in estimated cash flows	**90**	**5**	**95**
Revisions in discount rates	**(227)**	**—**	**(227)**
Reversals	**—**	**(10)**	**(10)**
Change in foreign exchange rates	**16**	**—**	**16**
Balance, Sept. 30, 2022	**682**	**18**	**700**

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	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Current portion	35	13	48
Non-current portion	758	21	779
Balance, Sept. 30, 2022	**682**	**18**	**700**
Current portion	**38**	**11**	**49**
Non-current portion	**644**	**7**	**651**

For the three months ended Sept. 30, 2022, the Company accelerated the expected timing on decommissioning and restoration for certain gas assets. This increased the decommissioning and restoration provision by $79 million resulting in an increase in PP&E of $29 million on operating assets and recognition of a $50 million impairment charge in net earnings related to retired assets. In the second quarter of 2022, an additional increase to decommissioning and restoration of $11 million was recognized in relation to an asset in the Gas segment.

For the nine months ended Sept. 30, 2022, the decommissioning and restoration provisions have decreased by $227 million due to a significant increase in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 6.8 to 9.6 per cent as at Sept. 30, 2022 (Dec. 31, 2021 — 3.6 to 6.5 per cent). This has resulted in a corresponding decrease in PP&E of $125 million on operating assets and recognition of a $102 million impairment reversal in net earnings related to retired assets.

18. Credit Facilities and Long-Term Debt

The Company has $2 billion (Dec. 31, 2021 — $2 billion) of committed syndicated bank facilities and $0.2 billion of committed bilateral credit facilities, of which $1.5 billion was available as at Sept. 30, 2022 (Dec. 31, 2021 — $1.3 billion) including the undrawn letters of credit. During the second quarter of 2022, the committed syndicated credit facilities were extended by one year to June 30, 2026 and the committed bilateral credit facilities were extended by one year to June 30, 2024. The undrawn credit facilities are the primary source for short-term liquidity after the cash flow generated from the Company's business. Interest rates on the credit facilities vary depending on the option selected (Canadian prime, bankers' acceptances, SOFR or US base rate, etc.) in accordance with a pricing grid that is standard for such facilities.

During the third quarter of 2022, the Company closed a two year $400 million floating rate Term Facility with its banking syndicate with a maturity date of Sept. 7, 2024. The Term Facility has interest rates that vary depending on the option selected (Canadian prime, bankers' acceptances, etc.) The Company is required to meet certain specific and customary affirmative and negative financial covenants under the Term Facility, including the maintenance of certain financial ratios. No amounts were drawn on the Term Facility as at Sept. 30, 2022.

As at Sept. 30, 2022, the Company was in compliance with all debt covenants.

Kent Hills Wind Bonds

In fourth quarter of 2021, the Company disclosed that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Accordingly, the Company classified the entire carrying value of the bonds as current as at Dec. 31, 2021.

During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon receipt of the waiver, the Company reclassified a portion of the carrying value outstanding for the KH Bonds to non-current liabilities with the exception of the scheduled principal repayments due within the next twelve months from June 30, 2022. In accordance with the supplemental indenture, Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed.

The KH Bonds, issued in October 2017, bear interest at 4.45 per cent, with principal and interest payable quarterly in blended payments until maturity on Nov. 30, 2033. The KH Bonds are secured by a first ranking charge over all of the assets of the issuer, Kent Hills Wind LP, which primarily includes the Kent Hills 1, 2 and 3 wind facilities, which at Sept. 30, 2022, had a combined PP&E carrying value of $210 million (Dec. 31, 2021 — $182 million).

Restricted Cash

The Company has $18 million (Dec. 31, 2021 — $17 million) of restricted cash related to bonds ("TransAlta OCP bonds") issued by the Company's subsidiary, TransAlta OCP LP, which is required to be held in a debt service reserve account to fund scheduled future debt repayments.

The Company also had $47 million (Dec. 31, 2021 — $53 million) of restricted cash related to the TEC Hedland PTY Ltd bond; reserves are required to be held under commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

Currency Impacts

The strengthening of the US dollar has increased the US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $70 million as at Sept. 30, 2022 (Sept. 30, 2021 — decreased by $7 million due to weakening of the US dollar). Almost all of the US-denominated debt is hedged either through financial contracts or net investments in the US operations.

Additionally, the weakening of the Australian dollar has decreased the Australian-denominated non-recourse senior secured notes by approximately $43 million as at Sept. 30, 2022 (Sept. 30, 2021 — $41 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income.

19. Defined Benefit Obligations

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates, largely driven by increases in market benchmark rates, the defined benefit obligation decreased by approximately $46 million for the nine months ended Sept. 30, 2022, compared to Dec. 31, 2021. A 1 per cent increase in discount rates would have a $38 million impact on the defined benefit obligation.

During the third quarter of 2022, the Company made a voluntary contribution of $35 million to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale Mine. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

The liability for defined benefit obligations is $148 million as at Sept. 30, 2022 (Dec. 31, 2021 — $228 million).

20. 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			
	2022		2021	
	Common shares (millions)	**Amount**	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**271.0**	**2,901**	269.8	2,896
Purchased and cancelled under the NCIB	**(2.7)**	**(29)**	—	—
Effects of share-based payment plans	**0.9**	**6**	—	(3)
Stock options exercised	**0.2**	**1**	1.2	8
Issued and outstanding, end of period	**269.4**	**2,879**	271.0	2,901

B. Normal Course Issuer Bid Program

On May 24, 2022, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to renew its 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 7.16 per cent of its public float of common shares. Any common shares purchased under the NCIB are cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2022 and ends on May 30, 2023.

Shares purchased by the Company under the NCIB 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 deficit.

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

As at		**Sept. 30, 2022**	Dec. 31, 2021
Total shares purchased		**2,741,400**	—
Average purchase price per share	**$**	**12.50**	—
Total cost (millions)[(1)]	**$**	**34**	—
Weighted average book value of shares cancelled	**$**	**29**	—
Amount recorded in deficit	**$**	**5**	—

(1) During the nine months ended Sept. 30, 2022, the Company paid $28 million with the remaining costs paid subsequent to the period.

C. Dividends.

On July 27, 2022, the Company declared a quarterly dividend of $0.05 per common share, payable on Oct. 1, 2022.

On Nov. 7, 2022, the Company declared a quarterly dividend of $0.055 per common share, payable on Jan. 1, 2023.

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

21. Preferred Shares

A. Issued and Outstanding

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

As at	**Sept. 30, 2022**		Dec. 31, 2021	
Series	**Number of shares (millions)**	**Amount**	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B(1)	**2.4**	**58**	2.4	58
Series C(2)	**10.0**	**243**	11.0	269
Series D(2)(3)	**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) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.
(2) During the second quarter of 2022, the Company has converted 1,044,299 of its 11,000,000 currently outstanding Series C Shares, on a one-for-one basis, into Series D Shares.
(3) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.10 per cent.

On Sept. 21, 2022, the Company announced that, after taking into account all election notices received for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 89,945 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2022 to but excluding Sept. 30, 2027, will be 6.894% which is equal to the five-year Government of Canada bond yield of 3.244 per cent, determined as of Aug. 31, 2022, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

B. Dividends

On July 27, 2022, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.22099 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.28841 per share on the Series D preferred shares, $0.32463 per share on the Series E preferred shares and $0.31175 per share on the Series G preferred shares, payable on Sept. 30, 2022.

On Nov. 7, 2022, the Company declared a quarterly dividend of $$0.17981 per share on the Series A preferred shares, $0.337 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.40442 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, 2022.

22. Commitments and Contingencies

A. Commitments

For the significant commitments and contingencies outstanding, refer to Note 36 of the 2021 annual consolidated financial statements. The Company has entered into the following material contractual commitments, as at Sept. 30, 2022:

During the second quarter of 2022, the Company entered into an engineering, procurement and construction agreement for approximately $37 million (AU$41 million) related to the Mount Keith 132kV Expansion.

During 2022, the Company has entered into agreements for $100 million for the rehabilitation efforts at the Kent Hills 1 and 2 wind facilities.

The Company has not incurred any other material contractual commitments, either directly or through its interests in joint ventures or associates during 2022.

B. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required. For the current material outstanding contingencies, please refer to Note 36 of the 2021 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement ("Hydro PPA") - Emission Performance Credits

The Balancing Pool is claiming entitlement to the 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 Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change-in-law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing is scheduled for Feb. 6 - 10, 2023. TransAlta holds approximately 1,750,000 EPCs with no recorded book value that were created between 2018-2020, which are at risk as a result of the Balancing Pool's claim.

Keephills Unit 1 Stator Force Majeure

The Balancing Pool and ENMAX were seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX appealed this decision to the Court of Appeal, which was heard on Jan. 27, 2022.

On June 9, 2022, the Court of Appeal released a unanimous decision dismissing ENMAX and the Balancing Pool's application. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills Unit 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta. ENMAX and the Balancing Pool did not seek leave to appeal this decision to the Supreme Court of Canada, which concludes this matter.

Keephills Unit 2 Stator Force Majeure

After the Keephills Unit 1 stator force majeure outage in 2013, it was determined that Keephills Unit 2 could face a similar stator failure before the next planned outage. In response, the Company took Keephills Unit 2 offline between January 31, 2014, and March 15, 2014, to perform a full rewind of the generator stator and claimed force majeure. The Balancing Pool disputed this force majeure event but the dispute was held in abeyance pending the outcome of the Keephills Unit 1 stator force majeure dispute, which was recently concluded. The Company and the Balancing Pool recently settled this dispute and so both stator force majeure claims have been resolved.

Sarnia Outages

The Sarnia cogeneration facility experienced three separate events between May 19, 2021, and June 9, 2021, that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. A root cause failure analysis was completed for the three outages, which concluded that all three outages were within TransAlta (SC) LP’s control. As such, liquidated damages previously included in contract liabilities in the amount of $12 million have been paid by TransAlta (SC) LP during the second quarter of 2022.

There have been no other material updates to any of the contingencies in the three and nine months ended Sept. 30, 2022.

23. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1.

The following tables provide each segment's results in the format that the 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. Prior periods have been adjusted for comparable purposes.

For internal reporting purpose, the earnings information from the Company's investment in the Skookumchuck wind facility 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 (Loss) and Segment Assets

Reconciliation of Adjusted EBITDA to Earnings (Loss) Before Income Tax

3 months ended Sept. 30, 2022	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	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 (gain) loss	—	53	47	6	46	—	152	—	(152)	—
Realized (gain) 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(4)	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) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

3 months ended Sept. 30, 2021	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass Adjustments	IFRS Financials
Revenues	96	55	384	231	86	1	853	(3)	—	850
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	21	(71)	(2)	(14)	—	(66)	—	66	—
Realized loss on closed exchange positions	—	—	—	—	21	—	21	—	(21)	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	96	76	326	229	93	1	821	(3)	32	850
Fuel and purchased power(4)	4	4	129	190	—	1	328	—	—	328
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(26)	(48)	—	—	(74)	—	74	—
Coal inventory write-down	—	—	—	(5)	—	—	(5)	—	5	—
Adjusted fuel and purchased power	4	4	102	137	—	1	248	—	80	328
Carbon compliance	—	—	33	14	—	—	47	—	—	47
Gross margin	92	72	191	78	93	—	526	(3)	(48)	475
OM&A(4)	10	14	42	28	14	23	131	(1)	—	130
Reclassifications and adjustments:										
Parts and materials write-down	—	—	—	(5)	—	—	(5)	—	5	—
Adjusted OM&A	10	14	42	23	14	23	126	(1)	5	130
Taxes, other than income taxes	—	3	4	1	—	1	9	—	—	9
Net other operating (income) loss	—	—	(10)	57	—	—	47	—	—	47
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(58)	—	—	(58)	—	58	—
Adjusted net other operating income	—	—	(10)	(1)	—	—	(11)	—	58	47
Adjusted EBITDA(5)	82	55	155	55	79	(24)	402			
Equity income										1
Finance lease income										6
Depreciation and amortization										(123)
Asset impairment charges										(575)
Net interest expense										(63)
Foreign exchange gain										1
Gain on sale of assets and other										23
Loss before income taxes										(441)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the three months ended Sept. 30, 2021, $1 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

9 months ended Sept. 30, 2022	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	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 (gain) 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[4]	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) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

9 months ended Sept. 30, 2021	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	299	225	937	471	185	6	2,123	(12)	—	2,111
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	22	(122)	27	(26)	—	(99)	—	99	—
Realized loss on closed exchange positions	—	—	1	—	49	—	50	—	(50)	—
Decrease in finance lease receivable	—	—	30	—	—	—	30	—	(30)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	299	247	862	498	208	6	2,120	(12)	3	2,111
Fuel and purchased power[4]	13	11	347	411	—	6	788	—	—	788
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Mine depreciation	—	—	(79)	(100)	—	—	(179)	—	179	—
Coal inventory write-down	—	—	—	(16)	—	—	(16)	—	16	—
Adjusted fuel and purchased power	13	11	265	295	—	6	590	—	198	788
Carbon compliance	—	—	104	35	—	—	139	—	—	139
Gross margin	286	236	493	168	208	—	1,391	(12)	(195)	1,184
OM&A[4]	29	42	129	97	31	55	383	(2)	—	381
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(28)	—	—	(30)	—	30	—
Adjusted OM&A	29	42	127	69	31	55	353	(2)	30	381
Taxes, other than income taxes	2	8	11	5	—	1	27	(1)	—	26
Net other operating (income) loss	—	—	(30)	56	—	—	26	—	—	26
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(58)	—	—	(58)	—	58	—
Adjusted net other operating income	—	—	(30)	(2)	—	—	(32)	—	58	26
Adjusted EBITDA[5]	255	186	385	96	177	(56)	1,043			
Equity income										5
Finance lease income										19
Depreciation and amortization										(395)
Asset impairment charges										(620)
Net interest expense										(186)
Foreign exchange gain										22
Gain on sale of assets and other										56
Loss before income taxes										(348)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the nine months ended Sept. 30, 2021, $6 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the condensed consolidated statements of earnings (loss) and the condensed consolidated statements of cash flows is presented below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2022	2021	**2022**	2021
Depreciation and amortization expense on the condensed consolidated statements of earnings (loss)	**179**	123	**411**	395
Depreciation included in fuel and purchased power (Note 4)	**—**	74	**—**	179
Depreciation and amortization on the condensed consolidated statements of cash flows	**179**	197	**411**	574

Glossary of Key Terms

Alberta Electric System Operator ("AESO")
The independent system operator and regulatory authority for the Alberta Interconnected Electric System.

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

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.

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.

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 energy, regardless of whether or not it is actually generating energy.

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.

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.

Centralia
The business segment previously disclosed as US Coal has been renamed to reflect the sole asset.

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

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

Dispatch optimization
Purchasing power to fulfill contractual obligations, when economical.

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

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.

IFRS
International Financial Reporting Standards.

ICFR
Internal control over financial reporting.

KH Bonds
The Kent Hills Wind LP ("KHLP") non-recourse project bonds secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities.

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.

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, Appleton and Moose Rapids facilities.

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.

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.

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

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