# TRANSALTA CORPORATION

## Second Quarter Report for 2021

## Management's Discussion and Analysis

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

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 six months ended June 30, 2021 and 2020, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2020 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", 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 June 30, 2021. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Aug. 9, 2021. Additional information respecting TransAlta, including its Annual Information Form, 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.

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# Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws, and "forward-looking statements" within the meaning of applicable United States securities laws, including the United States Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from 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: our conversions to gas and planned outages, including the conversion of Keephills Unit 3; the repowering of Sundance Unit 5 into a combined cycle unit, including delivering notice to proceed and the timing and cost of such repowering project; the shutting down of the Highvale Mine, eliminating coal as a fuel source in Alberta by the end of 2021 and realizing the benefits of the transition off-coal; expected increases to our cost per tonne of coal; the expected impact and quantum of carbon compliance costs; the Garden Plain wind project, including the expected timing of commercial operations and costs thereof; the growth of the renewables fleet, including the Northern Goldfields Solar Project and the Windrise Wind Project and the timing of commercial operations and total estimated spend in respect of such projects; the ability to realize future growth opportunities with BHP (as defined below); regulatory developments and their expected impact on the Corporation, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing, increased funding for clean technology and the implementation of the Clean Fuel Regulations (as defined below); the implementation of the US Jobs Plan (as defined below) and Australian renewable energy initiatives; the ability of the Corporation to realize benefits from the Canadian, US and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; the 2021 financial outlook, including comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA"), free cash flow ("FCF") and annualized dividend in 2021; increased gross margin contribution from Energy Marketing; sustaining and productivity capital in 2021, including routine capital, planned major maintenance and mine capital; Alberta hedge position for remainder of 2021 and 2022; significant planned major outages for 2021; lost production due to planned major maintenance for 2021; expected power prices in Alberta, Ontario and the Pacific Northwest; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; the satisfaction of the settlement conditions in respect of the dispute with Fortescue Metals Group Ltd. ("FMG"); and the Corporation continuing to maintain a strong financial position and significant liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the impacts arising from COVID-19 not becoming significantly more onerous on the Corporation, which includes the Corporation being able to continue to operate as an essential service; no significant changes to applicable laws and regulations beyond those that have already been announced, including no material changes to the applicable Carbon Tax and performance factors; no significant changes to the fuel and purchased power costs; no material adverse impacts to the long-term investment and credit markets; Alberta spot prices of $80/MWh to $100/MWh; Mid-Columbia spot prices of US$45/MWh to US$55/MWh; the Corporation's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the Alberta Thermal fleet and anticipated financial results generated on conversion or repowering; and the growth of TransAlta Renewables. 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 the impact of COVID-19, which cannot be predicted, and which present risks including, but not limited to: more restrictive directives of government and public health authorities; 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 and to obtain regulatory approvals on the expected timelines or at all; COVID-19 related force majeure claims; restricted access to capital and increased borrowing costs; changes in short-term and/or long-term electricity demand, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; further reductions in production; increased costs resulting from our efforts to mitigate the impact of COVID-19; changes in worldwide credit and financial markets; a higher rate of losses on our accounts receivable due to credit defaults; impairments and/or write-downs of assets; and adverse impacts on our information technology systems and our internal control systems, including increased cyber security threats. The forward-looking statements are also subject to other risk factors that include, but are not limited to: fluctuations in market prices; commodity risk management and energy trading risks, including the effectiveness of the Corporation's risk management tools associated with hedging and trading procedures to protect against significant losses, including the effect of unforeseen price variances from historical behavior; 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; operational risks involving our facilities, including unplanned outages and wind capacity factor; disruptions in the transmission and distribution of electricity; the effects of weather, including man made or natural disasters and other climate-change related risks; unexpected increases in cost structure; reductions to our units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas required for the converted or repowered generating units, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; the threat of terrorism, including cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment of future dividends, including from TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects; increased costs or delays in the conversion of coal-fired generating units to gas-fired generating units; increased costs or delays in the construction or commissioning of pipelines to converted units; inadequacy or unavailability of insurance coverage; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the other risks and uncertainties contained in the Corporation's Annual Information Form and Management's Discussion and Analysis for the year ended Dec. 31, 2020, filed under the Corporation's profile with the Canadian securities regulators on www.sedar.com and the US Securities and Exchange Commission ("SEC") on www.sec.gov.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on them, which reflect the Corporation's expectations only as of the date hereof. The purpose of the financial outlooks contained herein are 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 and is given as of the date of this MD&A. The forward-looking statements included in this MD&A and associated financial statements 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. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

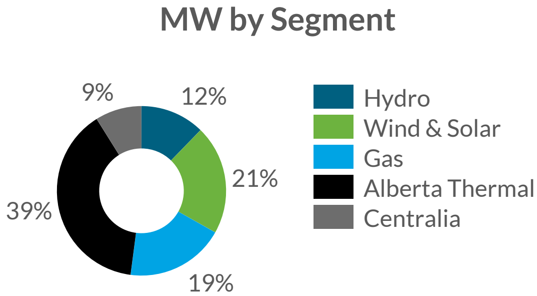
# Description of the Business

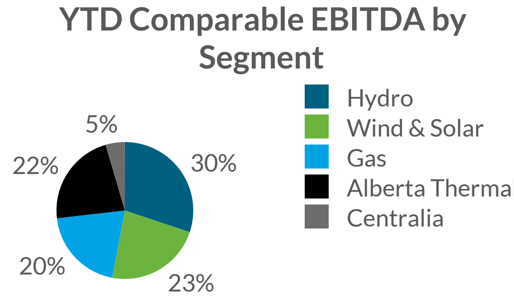
TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 110 years of operating experience. We own, operate and manage a highly contracted and geographically diversified portfolio of assets utilizing a broad range of fuels that include water, wind, solar, natural gas and thermal coal.

As at June 30, 2021, our asset base of gross installed capacity comprised 7,458 MW.

| | Alberta, Canada | | Canada, Excl. Alberta | | United States | | Australia | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross installed capacity (MW) | Number of facilities | Gross installed capacity (MW) | Number of facilities | Gross Installed capacity (MW) | Number of facilities | Gross installed capacity (MW) | Number of facilities | Gross installed capacity (MW) | Number of facilities |
| Hydro | 834 | 17 | 91 | 9 | 1 | 1 | — | — | 926 | 27 |
| Wind & Solar | 425 | 11 | 750 | 9 | 397 | 6 | — | — | 1,572 | 26 |
| Gas | 300 | 2 | 645 | 3 | 29 | 1 | 450 | 6 | 1,424 | 12 |
| Alberta Thermal(1) | 2,866 | 8 | — | — | — | — | — | — | 2,866 | 8 |
| Centralia | — | — | — | — | 670 | 1 | — | — | 670 | 1 |
| **Total** | **4,425** | **38** | **1,486** | **21** | **1,097** | **9** | **450** | **6** | **7,458** | **74** |

*(1) 4 facilities have been converted to gas.*




Excluding those facilities within the Alberta Electricity Portfolio, 91 per cent of TransAlta's gross installed capacity is covered by long-term power purchase agreements ("PPA"). These PPAs have a weighted average remaining contractual term of 9 years.

## Transition off-coal

The Corporation is currently in a multi-year transition to convert or retire all of our thermal coal units completely by the end of 2025. We are on track to eliminate coal as a fuel source in Alberta by the end of 2021. This transition will see our thermal coal units in Alberta discontinue firing with coal and the discontinuation of all coal mining operations by Dec. 31, 2021.

During the first half of 2021, we completed the conversion to gas at Sundance Unit 6 and our non-operated Sheerness Unit 1 completed its conversion to gas, resulting in both units running solely on gas. On July 19, 2021, we announced the completion of the conversion to gas at Keephills Unit 2 with a total spend of $35 million. The conversion of Keephills Unit 3 to gas is planned to begin mid-September, with completion expected at the end of November.

Completing our off-coal transition will reduce carbon compliance significantly in the future. In 2021, carbon compliance costs on coal fired production is approximately $27 per MWh, while carbon compliance costs on gas fired production is approximately $8 per MWh. During the second quarter of 2021, our carbon compliance costs were $37 million. Under a fully a converted Alberta fleet, carbon compliance costs would have been $15 million to $20 million dollars lower.

Our Centralia coal-fired facility in Washington State is committed to be retired under the *TransAlta Energy Transition Bill*. Consistent with our commitment under this bill, Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit is set to retire on Dec. 31, 2025.

The following table shows our completed conversions to gas:

| **Project** | **MW** | **Conversion Project Spend**(1) | **Project Completion Date** |
|---|---|---|---|
| Keephills Unit 2 | 395 | $35 | Q2 2021 |
| Sundance Unit 6 | 401 | $39 | Q1 2021 |
| Sheerness Unit 1 | 400 | $7 | Q1 2021 |
| Sheerness Unit 2 | 400 | $14 | Q1 2020 |

*(1) Conversion project spend only includes costs associated with the conversion to gas-burning technology. Any additional planned major maintenance has been included as part of sustaining capital spend.*

The following table shows our on-going conversions to gas projects and status of these projects:

| Project | MW | Total project Estimated spend | Spend to date | Remaining estimated spend in 2021 | Target completion date[1] | Status |
|---|---|---|---|---|---|---|
| Keephills Unit 3 | 463 | 31 — 35 | 14 | 17 | Q4 2021 | Major equipment has been received at site and pre-outage construction activities are now underway |
| Sundance Unit 5 Repowering[2] | 746 | 900 — 950 | 154 | 146 | H1 2024 | The Corporation continues to evaluate and assess the Sundance Unit 5 repowering project in light of escalating costs, the changing supply and demand dynamics in the Alberta market, as well as the evolving regulatory environment. The Corporation has completed an additional competitive tendering process for the engineering, procurement and construction contract and is now reviewing those bids as well as the overall Sundance 5 repowering project costs. |

*(1) H1 is defined as the first half of the year .*
*(2) On July 29, 2021, in accordance with applicable regulatory requirements, the Corporation has provided notice to the Alberta Electric System Operator ("AESO") of its intention to retire the coal-fired unit on Nov. 1, 2021.*

## Alberta Electricity Portfolio

The Alberta Electricity Portfolio includes hydro, wind, energy storage and thermal units operating, primarily, on a merchant basis in the Alberta market. The variability in production by facility is driven by the diversity in our fuel types, which enables portfolio management and allows for maximization of operating margins. A portion of the installed generation capacity in the portfolio has been hedged to provide cash flow certainty.

On Dec. 31, 2020, the Alberta Power Purchase Arrangements ("Alberta PPA") for our Alberta Hydro Assets, Sheerness 1 and 2 Units, and the Keephills 1 and 2 Units expired. Effective Jan. 1, 2021, these facilities began operating on a fully merchant basis in the Alberta market and form a core part of our Alberta portfolio optimization activities.

The following table provides information for the Corporation's Alberta Electricity Portfolio:

| | 3 Months Ended June 30, | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Production (GWh) | | | | |
| Hydro | **423** | 534 | **750** | 845 |
| Wind | **204** | 259 | **507** | 600 |
| Gas | **105** | 133 | **250** | 282 |
| Thermal | **2,386** | 2,151 | **4,494** | 5,124 |
| Total Alberta Electricity Portfolio Production (GWh) | **3,118** | 3,077 | **6,001** | 6,851 |
| Alberta Electricity Portfolio comparable revenues[1] | **$352** | $188 | **$652** | $446 |
| Economic hedge position (percentage) - Alberta Thermal[2] | 71 | 100 | 73 | 100 |
| Spot power price average per MWh | **$105** | $30 | **$100** | $48 |
| Realized power prices per MWh[1,3] | **$113** | $61 | **$109** | $65 |

*(1) Includes comparable adjustments to revenues. 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) Represents the percentage of production sold forward at the end of the reporting period for the Alberta Thermal assets only. The hedge program is focused primarily on generation from the Alberta Thermal assets.*
*(3) Realized power price for the Alberta Electricity Portfolio is the average price realized as a result of the Corporation's commercial contracted sales and portfolio optimization activities divided by total GWh produced.*

# Highlights

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Adjusted availability (%)(1) | **84.8** | 91.5 | **86.7** | 92.2 |
| Production (GWh) | **4,688** | 4,607 | **10,229** | 11,093 |
| Revenues | **619** | 437 | **1,261** | 1,043 |
| Fuel and purchased power(2) | **212** | 116 | **455** | 309 |
| Carbon compliance(2) | **42** | 35 | **92** | 80 |
| Operations, maintenance and administration | **151** | 112 | **256** | 240 |
| Net loss attributable to common shareholders | **(12)** | (60) | **(42)** | (33) |
| Cash flow from operating activities | **80** | 121 | **337** | 335 |
| Comparable EBITDA(3) | **302** | 217 | **612** | 437 |
| Funds from operations(3) | **250** | 159 | **461** | 331 |
| Free cash flow(3) | **138** | 91 | **267** | 200 |
| Net loss per share attributable to common shareholders, basic and diluted | **(0.04)** | (0.22) | **(0.16)** | (0.12) |
| Funds from operations per share(3) | **0.92** | 0.58 | **1.70** | 1.20 |
| Free cash flow per share(3) | **0.51** | 0.33 | **0.99** | 0.72 |
| Dividends declared per common share(4) | **0.0450** | 0.0425 | **0.0450** | 0.0850 |
| Dividends declared per preferred share(5) | **0.2536** | 0.2533 | **0.2536** | 0.5123 |

| **As at** | **June 30, 2021** | Dec. 31, 2020 |
|---|---|---|
| Total assets | **9,366** | 9,747 |
| Total consolidated net debt(3,6) | **2,784** | 2,975 |
| Total long-term liabilities | **5,066** | 5,376 |

*(1) Prior period adjusted availability has been revised to include our Hydro segment.*
*(2) In the first and second quarters of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.*
*(3) 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 trends more readily in comparison with prior periods' results. 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.*
*(4) No dividends were declared in first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.*
*(5) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.*
*(6) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable debentures, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash in TransAlta OCP LP ("OCP") and the fair value of economic hedging instruments on debt. See the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.*

For our three and six months ended June 30, 2021, we have seen outstanding performance from our Alberta Electricity Portfolio, driving an overall strong performance for the Corporation. Both our Hydro and Alberta Thermal segments had excellent availability during periods of peak pricing, which were the result of abnormally warm weather combined with periods of province-wide planned thermal outages. The Alberta merchant portfolio was positioned to capture opportunities from these strong spot market conditions through both energy and ancillary services revenues. This was further supplemented by strong performance in our Energy Marketing segment. We have revised and increased our guidance in the quarter for comparable EBITDA and FCF as we have modified our expectation on Alberta electricity prices for the remainder of the year. Please refer to the 2021 Financial Outlook section of this MD&A for more details on our updated guidance.

Adjusted availability for the three and six months ended June 30, 2021, was 84.8 per cent and 86.7 per cent, respectively, compared to 91.5 per cent and 92.2 per cent, for the same periods in 2020. The decrease was primarily due to higher planned and unplanned outages in the Centralia segment, Hydro segment and North American Gas segment, the planned outage for the Keephills 2 boiler conversion and higher derates at the Alberta Thermal segment. The adverse year-on-year impact from the Centralia outages were greater in the current year due to the retirement of Centralia Unit 1 in December 2020.

Production for the three and six months ended June 30, 2021 was 4,688 GWh and 10,229 GWh, respectively, compared to 4,607 GWh and 11,093 GWh for the same periods in 2020. The slight increase in production for the three-month period ended was due to higher dispatch optimization at the Alberta Thermal segment and lower dispatch optimization at the Centralia segment, which was substantially offset by lower availability at the Hydro and Centralia segments, lower wind resources in the Wind and Solar segment and the retirement of Centralia Unit 1. The decrease in production for the six-month period ended was primarily due to portfolio optimization activities at the Alberta Thermal segment, lower adjusted availability across the fleet, lower wind resources in the Wind and Solar segment and the retirement of Centralia Unit 1 which was partially offset by lower dispatch optimization in the Centralia segment and higher production in North American Gas segment from the addition of the Ada facility.

Revenues for the three and six months ended June 30, 2021, increased $182 million and $218 million, respectively, compared to the same periods in 2020, mainly as a result of capturing higher realized prices within the Alberta market through our optimization and operating activities and the elimination of the net payment obligations under the Alberta PPAs in the prior period. Revenues also increased due to the strong performance from the Energy Marketing segment, an increase in revenues within the North American Gas segment from the addition of the Ada facility and an increase within the Wind and Solar segment from the addition of Skookumchuck facility. These increases were partially offset by lower production in the Alberta Thermal, Centralia and Wind and Solar segments.

Fuel and purchased power costs increased by $96 million and $146 million in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020. In our Centralia segment, our margins declined compared to 2020 as we acquired higher-priced power to fulfil our contractual obligations during planned and unplanned outages during the periods of higher merchant pricing. In addition, the Alberta Thermal segment had higher gas pricing, higher coal mine depreciation and coal inventory write-downs at the Highvale mine, all of which contributed to higher fuel costs.

Carbon compliance costs increased by $7 million and $12 million in the three and six months ended June 30, 2021, respectively, compared to the same periods in 2020 due to an increase in the carbon price per tonne, partially offset by reductions in greenhouse gas ("GHG") emissions stemming from changes in the fuel mix ratio as we operate more on natural gas and fire less with coal. Operating with natural gas reduces carbon compliance costs as we produce fewer GHG emissions than by using coal. In addition, for the three-month period ended June 30, 2021, the Alberta Thermal segment had increased production which contributed to higher carbon compliance costs, whereas for the six-month period ended June 30, 2021, carbon compliance costs were partially offset by lower production at the Alberta Thermal segment.

Operations, maintenance and administration ("OM&A") expenses for the three and six months ended June 30, 2021, increased by $39 million and $16 million, respectively, compared to the same periods in 2020. During the second quarter of 2021, a writedown of $25 million was recorded on parts and material inventory related to the Highvale mine and coal operations at our gas converted facilities. In addition, for the three and six months ended June 30, 2021, variability caused by the total return swap resulted in an unfavourable change of $5 million and a favourable change of $13 million, respectively. During the first quarter of 2021, we received a Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap, CEWS funding and inventory writedown, OM&A expenses were higher for the three and six months ended June 30, 2021, compared to the same periods in 2020, primarily due to increased staffing costs for growth and strategic initiatives, settlement of provisions and higher incentive costs. As previously committed, the CEWS funding was used to support the incremental employment within the Corporation.

Comparable EBITDA for the three and six months ended June 30, 2021, increased by $85 million and $175 million, respectively, compared with the same periods in 2020, largely due to higher comparable EBITDA at our Alberta Thermal and Hydro segments which was partially offset by lower performance at the Centralia segment, North American Gas segment and Wind and Solar segment. On a year-to-date basis, our Energy Marketing segment also had stronger results compared to 2020. Significant changes in segmented comparable EBITDA are highlighted in the Segmented Comparable Results within this MD&A.

FCF, one of the Corporation's key financial metrics, totaled $138 million and $267 million for the three and six months ended June 30, 2021, respectively. This represents an increase of $47 million and $67 million compared to the same periods in 2020, driven primarily by the higher comparable EBITDA, partially offset by an increase in sustaining capital, settlement of provisions and higher distributions paid to subsidiaries' non-controlling interests.

Net loss attributable to common shareholders for the three and six months ended June 30, 2021, was $12 million and $42 million, respectively, compared to net losses of $60 million and $33 million, respectively, in the same periods in

2020. For the three and six months ended June 30, 2021, net earnings attributable to common shareholders increased by $48 million and net earnings decreased by $9 million, respectively, from the same periods in 2020 from higher comparable EBITDA, the gain on the sale of the Pioneer Pipeline and lower depreciation, which were partially offset by higher income tax. In the six month period ended June 30, 2021, earnings were additionally impacted by an increase in finance lease income, higher foreign exchange changes, which were also offset by greater asset impairments than from the same period in 2020.

# Corporate Strategy

Our goal is to deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share. Our segmented cash flow growth is driven by optimizing and diversifying our existing assets and further expanding our overall portfolio and presence in Canada, the United States of America and Australia. We are focused on these geographic areas as our expertise, scale and diversified fuel mix create a competitive advantage that we can leverage to capture expansion opportunities to create shareholder value. Our strategy is also guided by ambitious but achievable ESG targets, including our commitment to achieving carbon neutrality by 2050.

## Regulatory Developments

On Dec. 11, 2020, the Government of Canada released its "*A Healthy Environment and a Healthy Economy*" climate plan that outlines how the federal government intends to use policies, regulations and funding to achieve Canada's Paris Agreement emissions reduction target. The three major aspects of the plan include increased carbon prices and obligations, increased funding for clean technology and the implementation of the Clean Fuel Regulation ("CFR"). The 2021 federal budget proposed significant spending to undertake the elements of the climate plan as well as additional measures, including a potential tax credit for carbon capture, utilization and storage. On April 22, 2021, Prime Minister Trudeau increased Canada's GHG reduction target from 40 to 45 per cent below 2005 levels by 2030. The government stated that it will consult with provinces and industry regarding many elements of the plan so significant uncertainty remains regarding the final form of the related regulations and other initiatives. This policy will provide TransAlta with the opportunity to provide clean electricity solutions to industries seeking to reduce their regulatory exposure, benefit from federal funding for clean electricity projects, and may, under certain circumstances, increase the value of emissions reductions credits from new renewables projects.

On March 31, 2021, President Biden announced his American Jobs Plan (the "US Jobs Plan") which is heavily focused on climate change. The US Jobs Plan proposes to spend $2 trillion over the next decade to rebuild transportation infrastructure, make existing and new infrastructure climate change resilient, create cleaner energy systems, support the deployment of electric vehicles and ensure job growth, particularly for low income and communities of colour. This plan will increase demand for electricity in the US market. This policy provides TransAlta with the opportunity to benefit from further government incentives for renewables development and an overall uplift in demand due to increased electrification of the economy and continued corporate efforts to decarbonize to meet regulatory and ESG objectives.

Australia's transition to renewables has been historically facilitated by a combination of Commonwealth and State government renewable energy initiatives. Currently, all Australian states have state-based renewable energy targets, with many having aggressive near term targets. The two largest states by population, New South Wales ("NSW") and Victoria, have legislated targets of 60 per cent renewables and 50 per cent renewables, respectively, by 2030. The need for firm supply and storage as part of a rapid renewable transition has also been recognized and some states have included targets for this in their renewable transition programs, such as NSW and Queensland. Within the National Electricity Market ("NEM"), renewable energy zones are being established as a means of seeking to reduce some network access and network performance risk for new renewable and storage projects. The regulatory framework supporting the renewable transition is still evolving and the rapid supply system transition, which will result from the above initiatives, provides an opportunity for the entry of a considerable volume of new renewable generation and storage capacity into the NEM and potential opportunities for TransAlta to participate.

In Australia, corporations are responding to government initiatives, as well as feedback from shareholders and customers with many committing to CO2 reduction targets above and beyond legislated targets. This provides additional support for investments in renewable projects such as the recently announced solar farm to be built by TransAlta for its customer, BHP Nickel West, at Mount Keith and Leinster in Western Australia.

## Growth

The Corporation remains well positioned to grow in our key markets. We are focused on developing generation solutions for customers that meet their needs for reliable and low-cost clean energy solutions. As illustrated in the tables below, the Corporation continues to build a strong portfolio of growth opportunities with potential capacity ranging from 3,180 MW to 3,780 MW from projects at various stages of development.

### New Announced Projects

*BHP Nickel West Solar Contract*

The Corporation reached agreement to provide BHP Nickel West Pty Ltd. ("BHP") with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Construction activities are scheduled to start in the fourth quarter of 2021 with completion of the projects expected in the second half of 2022. Total construction capital of the project is estimated at approximately AU$73 million. This is the first major growth project agreed under the extended power purchase agreement that was executed in October of 2020. The Corporation continues to actively explore other growth opportunities with BHP.

*Garden Plain Wind Project*

The Corporation entered into a long-term PPA with Pembina Pipeline Corporation ("Pembina") pursuant to which Pembina has contracted for the renewable electricity and environmental attributes for 100 MW of the 130 MW Garden Plain wind project ("Garden Plain"). Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the quantity under the PPA). The option must be exercised no later than 30 days after the commercial operational date. TransAlta would remain the operator of the facility and earn a management fee if Pembina exercises this option. Garden Plain will be located approximately 30 km north of Hanna, Alberta. Construction activities are scheduled to start in fall 2021 with completion of the project expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

## Projects Under Construction

These projects have been approved by the Board, have PPAs in place 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 as a long-term financing solution on an asset-by-asset basis.

| Project | Type | Region | MW | Total project Estimated spend | Target completion date[1] | PPA Term | Expected Annual EBITDA[2] | Status |
|---|---|---|---|---|---|---|---|---|
| **Projects Under Construction** | | | | | | | | |
| **Canada** | | | | | | | | |
| Windrise[3] | Wind | AB | 207 | 270 — 285 | H2 2021 | 20 | 20 - 22 | – Turbine erection activities are ongoing<br>– Transmission line was energized on June 10<br>– As at June 30, 2021, the project was approximately 88 per cent complete |
| Garden Plain[4] | Wind | AB | 130 | 190 — 200 | H2 2022 | 18 | 14 - 18 | – Wind turbines have been ordered<br>– Advancing through detailed engineering in preparation for the procurement processes<br>– Completed full geotechnical investigation<br>– Obtained an amended AUC Permit and License for the facility<br>– On track to be completed on time |
| **Australia** | | | | | | | | |
| Northern Goldfields[5] | Hybrid Solar | WA | 48 | 64 — 68 | H2 2022 | 16 | 8-9 | – Limited Notice to Proceed has been issued for the order of long lead items. |
| **Total** | | | **385** | **524 — 553** | | | **42 - 49** | |

*(1) H2 is defined as the second half of the year.*
*(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 trends more readily in comparison with prior periods' results. 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.*
*(3) The Windrise wind development project was sold to TransAlta Renewables on Feb. 26, 2021.*
*(4) The Garden Plain PPA is for 100 MW of the total 130 MW capacity of the facility.*
*(5) The numbers reflected above are in Canadian dollars, but the actual cash spend on this project is in Australian dollars and therefore these amounts will fluctuate with changes in foreign exchange rates. Estimated spend is approximately AU$69 million to AU$73 million and expected annual EBITDA is approximately AU$9 million to AU$10 million.*

## Advanced Stage Development

These projects have detailed engineering, advanced position 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 | Expected Annual EBITDA[1] |
|---|---|---|---|---|---|
| **Advanced Stage Development** | | | | | |
| **US** | | | | | |
| Horizon Hill | Wind | Oklahoma | 200 | US$275 - US$290 | US$20 - US$30 |
| White Rock East | Wind | Oklahoma | 200 | US$275 - US$290 | US$20 - US$30 |
| White Rock West | Wind | Oklahoma | 100 | US$135 - US$145 | US$10 - US$15 |
| | | **Total** | **500** | **US$685 - US$725** | **US$50 - US$75** |

*(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. 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.*

## 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 |
| Willow Creek 1 & 2 | Wind | Alberta | 140 |
| Tempest | Wind | Alberta | 90 |
| Alberta Storage Opportunities | Battery Storage | Alberta | 100 |
| Cogeneration Opportunities | Gas | Alberta and Ontario | 30 |
| Alberta Solar Opportunities | Solar | Alberta | 170 |
| Canadian Wind Opportunities | Wind | Alberta & Saskatchewan | 250 |
| Brazeau Pumped Hydro | Hydro | Alberta | 300 - 900 |
| | | **Total** | **1,380 - 1,980** |
| **US** | | | |
| Prairie Violet | Wind | Illinois | 185 |
| Big Timber | Wind | Pennsylvania | 50 |
| Wild Waters | Wind | Minnesota | 40 |
| PJM Wind Prospects | Wind | Pennsylvania/Wyoming | 220 |
| US Solar Prospects | Solar | Texas/Indiana | 200 |
| | | **Total** | **695** |
| **Australia** | | | |
| Northern Goldfields Expansions | Gas, Solar and Wind | Western Australia | 85 |
| South Hedland Solar | Solar | Western Australia | 50 |
| Remote mining on-site | Gas | Western Australia | 85 |
| | | **Total** | **220** |

# Significant and Subsequent Events

## BHP Nickel West Solar Contract

On July 29, 2021, TransAlta Renewables announced that Southern Cross Energy, a subsidiary of the Corporation and an entity in which TransAlta Renewables owns an indirect economic interest, had reached an agreement to provide BHP with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Construction activities are scheduled to start in the fourth quarter of 2021 with completion of the projects expected in the second half of 2022. Total construction capital of the project is estimated at approximately AU$73 million.

## Sundance Unit 5 Retirement as a Coal-Fired Unit

On July 29, 2021, in accordance with applicable regulatory requirements, the Corporation gave notice to the AESO of its intention to retire the currently mothballed coal-fired Sundance Unit 5 effective Nov. 1, 2021 and to terminate the associated transmission service agreement. Under the applicable regulatory rules, a mothball outage can extend no later than 24 months after the commencement of such mothball outage; following which time either the unit must be returned to service, or the transmission service agreement must be terminated (effectively retiring the unit as a coal-fired facility). The AESO had previously granted the extension of the mothball outage for the Sundance Unit 5 mothballed outage to Nov. 1, 2021. As a result, Sundance Unit 5 will not be returning to service as a coal-fired unit.

## Keephills Unit 2 and Sundance Unit 6 Conversion to Gas Completions

On July 19, 2021, the Corporation announced the completion of the full conversion of Keephills Unit 2 from thermal coal to natural gas. In February 2021, the Corporation also completed the conversion of Sundance Unit 6. Both Keephills Unit 2 and Sundance Unit 6 will maintain the same generator nameplate capacity of 395 MW and 401 MW, respectively. These conversion to gas projects will reduce our CO2 emissions by more than half and advances our plan to be 100 per cent clean electricity in Alberta by the end of 2021.

## Sale of the Pioneer Pipeline

On June 30, 2021, the Corporation closed the previously announced sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest, are approximately $128 million, subject to certain adjustments. Following closing of the transaction, the Pioneer Pipeline will be integrated into NOVA Gas Transmission Ltd. ("NGTL") and ATCO's Alberta natural gas transmission systems to provide reliable natural gas supply to the Corporation's power generation stations at Sundance and Keephills. As part of the transaction, TransAlta has entered into additional long-term gas transportation agreements with NGTL for new and existing transportation service of 400 TJ per day by the end of 2023.

## Garden Plain Wind Project

On May 3, 2021, the Corporation announced that it entered into a long-term PPA with Pembina pursuant to which Pembina has contracted for the renewable electricity and environmental attributes for 100 MW of the 130 MW Garden Plain project. Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the quantity under the PPA). The option must be exercised no later than 30 days after the commercial operational date. TransAlta would remain the operator of the facility and earn a management fee if Pembina exercises this option. Garden Plain will be located approximately 30 km north of Hanna, Alberta. Construction activities are scheduled to start in fall 2021 with completion of the project expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

## Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. The agreement provides that if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the agreement will automatically terminate on Dec. 31, 2025. The Corporation is in active discussions with the three other existing industrial off-takers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. On July 19, 2021, the IESO released an Annual Acquisition Report which included draft details for mid and long-term procurement mechanisms for capacity for 2026 and beyond for existing and new generation. The Corporation will participate in the consultation process, seeking to secure a contract extension for the Sarnia Cogeneration facility following the end of the current contract.

### TransAlta Renewables is named on the Best 50 Corporate Citizens List

During the second quarter of 2021, TransAlta Renewables, a subsidiary of the Corporation, was recognized by Corporate Knights as one of the Best 50 Corporate Citizens for 2021. The Best 50 Corporate Citizens list evaluates and ranks Canadian corporations against a set of 24 key performance indicators covering environmental, social and governance ("ESG") indicators relative to their industry peers and using publicly available information. The Corporation is committed to continuous improvement on key ESG issues and to ensuring its economic value creation is balanced with a value proposition for the environment and its communities.

### Equity, Diversity and Inclusion Program

On May 3, 2021, TransAlta announced that it had received certification from Diversio, a technology company setting the global standard for diversity and inclusion, for its continued commitment to and meaningful performance on equity, diversity and inclusion ("ED&I") in the workplace. TransAlta is the first publicly-traded energy company to be certified. The certification is endorsed by several leading organizations and signals to investors, employees, customers and other stakeholders that the Corporation is shifting from words to actions in order to move the dial on ED&I.

### Sustainability-Linked Loan

In March 2021, TransAlta extended its $1.25 billion Syndicated Credit facility to June 30, 2025 and converted the facility into a Sustainability-Linked Loan ("SLL"). The facility's financing terms will align the cost of borrowing to TransAlta's GHG emission reductions and gender diversity targets, which are part of the Corporation's overall environment, social, and governance strategy, or ESG. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanism and could move either up, down or remain unchanged for each sustainability performance target based on performance. The SLL further underscores TransAlta's dedication to sustainability, including ED&I and emissions reduction.

### Mangrove Claim

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming the Corporation, the incumbent members of the Board of Directors (the "Board") of the Corporation on such date, and Brookfield BRP Holdings (Canada) as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

### Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021 and this matter is now resolved.

### TransAlta Renewables Acquisitions

The Corporation completed the sale of its 100 per cent direct interest in the 207 MW Windrise wind project ("Windrise") to TransAlta Renewables, a subsidiary of the Corporation, on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise will be paid by TransAlta Renewables. Windrise is expected to commence commercial operation in the second half of 2021.

On April 1, 2021, the Corporation completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility ("Ada") and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility ("Skookumchuck") to TransAlta Renewables for $43 million and $103 million, respectively. Both facilities are fully operational. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities. The Ada cogeneration facility is under a PPA until 2026. The Skookumchuck wind facility is contracted under a PPA until 2040 with an investment grade counterparty.

## Normal Course Issuer Bid

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of our 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 18, 2021. 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, 2021 and ends on May 30, 2022 or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

No common shares have been repurchased under the current and previous NCIB in 2021.

## Management Changes

On March 31, 2021, Dawn Farrell, President and Chief Executive Officer, retired from the Corporation and the Board. John Kousinioris succeeded Mrs. Farrell as President and Chief Executive Officer and joined the Board on April 1, 2021. Prior to his appointment as Chief Executive Officer of TransAlta, Mr. Kousinioris held the roles of Chief Operating Officer, Chief Growth Officer and Chief Legal and Compliance Officer and Corporate Secretary with the Corporation.

Effective April 30, 2021, Brett Gellner, our Chief Development Officer, retired after almost 13 years with TransAlta. Mr. Gellner will continue to serve on the Board of Directors of TransAlta Renewables as a non-independent director.

## Board of Director Changes

On May 4, 2021, the Corporation announced that the Board of Directors elected four new directors: Ms. Laura W. Folse, Ms. Sarah Slusser, Mr. Thomas O'Flynn and Mr. Jim Reid, who each bring diverse expertise and new perspectives to the Board. Mrs. Georgia Nelson, Mr. Richard Legault and Mr. Yakout Mansour did not stand for re-election and retired from the Board immediately following the annual shareholder meeting on May 4, 2021.

## COVID-19

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic.

The Corporation continues to operate under its business continuity plan, which focused on ensuring that: (i) employees who can work remotely do so; and (ii) employees who operate and maintain our facilities, and who are not able to work remotely, are able to work safely and in a manner that ensures their health and safety. TransAlta has adopted 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. All of TransAlta's offices and sites follow health screening and social distancing protocols, including personal protective equipment. Further, TransAlta maintains travel limitations that are aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to minimize any workplace transmission of the virus.

Notwithstanding the challenges associated with the pandemic, all of our facilities continue to remain fully operational and are capable of meeting our customers' needs. The Corporation continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

The Corporation continues to maintain a strong financial position due in part to its long-term contracts and hedged positions and its ample financial liquidity.

The Board and management have been monitoring the evolution of the pandemic and are continually assessing its impact to the safety of the Corporation's employees, operations, supply chains and customers as well as, more generally, to the business and affairs of the Corporation and our existing capital projects. Potential impacts of the pandemic on the business and affairs of the Corporation include, but are not limited to: potential interruptions of production; supply chain disruptions; unavailability of employees; potential delays in capital projects; increased credit risk with counterparties and increased volatility in commodity prices, as well as the valuation of financial instruments. In addition, the broader impacts to the global economy and financial markets could have potential adverse impacts on the availability of capital for investment and the demand for power and commodity pricing.

Please refer to Note 4 of the 2020 audited annual consolidated financial statements within our 2020 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2021, for significant events impacting both prior and current year results.

## 2021 Financial Outlook

Please refer to the 2021 Financial Outlook section in our 2020 Annual Integrated Report for full details on our 2021 Financial Outlook and related assumptions.

Our overall performance for the first half of 2021 is ahead of expectations. Electricity demand has recovered from its lows in 2020 and we are observing strengthening power prices in the Alberta and Pacific Northwest markets. As a result, the Corporation is revising upward its outlook range for comparable EBITDA and FCF.

The following table outlines our expectations on key financial targets and related assumptions for 2021:

| Measure | Original Target | Updated Target |
|---|---|---|
| Comparable EBITDA(1) | $960 million - $1,080 million | $1,100 million - $1,200 million |
| FCF(1) | $340 million - $440 million | $440 million - $515 million |
| Dividend | $0.18 per share annualized | No change |

*(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. 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.*

| Range of key power price assumptions | Original Expectations | Updated Expectations |
|---|---|---|
| **Market** | **Power Prices ($/MWh)** | **Power Prices ($/MWh)** |
| Alberta Spot | $58 - $68 | $80 - $100 |
| Mid-C Spot (US$) | US$25 - US$35 | US$45 - US$55 |
| **Other assumptions relevant to the 2021 financial outlook** | | |
| Sustaining capital | $175 million - $210 million | $200 million to $225 million |

### Alberta Hedging

| Range of hedging assumptions | Q3 - 2021 | Q4 - 2021 | 2022 |
|---|---|---|---|
| Hedged production (GWh) | 1,841 | 848 | 2,663 |
| Hedge Price ($/MWh) | 75 | 68 | 62 |
| Hedged gas volumes (GJ) | 14 million | 14 million | 44 million |
| Hedge gas prices ($/GJ) | 2.87 | 2.94 | 2.44 |

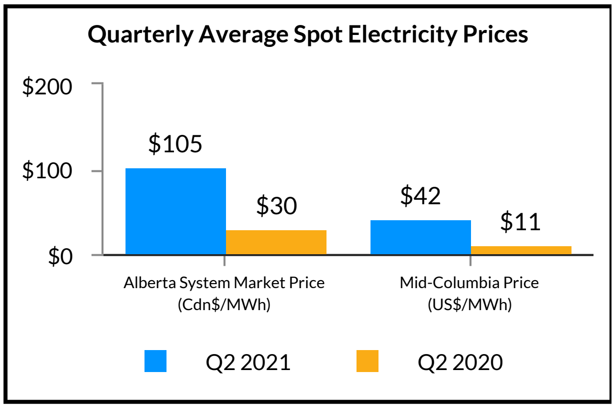
### Operations

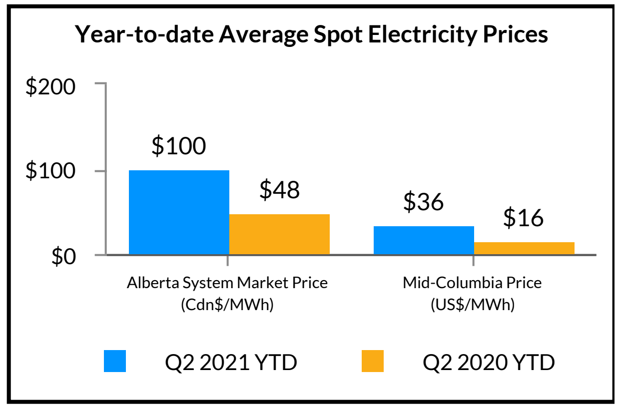
The following provides updates to our original assumptions included in the 2021 Financial Outlook.

#### Market Pricing

Power prices were higher in Alberta in the three and six months ended June 30, 2021, compared to the same periods in 2020. This resulted from commercial offer behavior following the expiry of the Alberta PPAs with the Balancing Pool on Dec. 31, 2020, higher carbon compliance costs, demand recovery from 2020, and tighter market conditions during periods of strong weather-driven demand in addition to planned outages. Alberta power prices for the remainder of 2021 are expected to continue to be higher than in 2020 as a result of the factors discussed above.

Power prices were also higher in the Pacific Northwest in the three and six months ended June 30, 2021, compared to the same periods in 2020, mainly due to lower hydro generation. Higher prices are expected in the Pacific Northwest for the remainder of 2021 compared to 2020.




### Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our updated 2021 objective for Energy Marketing is for the segment to contribute between $170 million to $200 million in gross margin for the year, an increase from the $90 million to $110 million communicated as part of our Management`s Discussion and Analysis at Dec. 31, 2020.

### Sustaining and Productivity Capital Expenditures

Our estimate for total sustaining and productivity capital is allocated among the following:

| Category | Description | Spent to date[1] | Expected spend in 2021 |
|---|---|---|---|
| Routine capital[2] | Capital required to maintain our existing generating capacity | **18** | 49 – 59 |
| Planned major maintenance | Regularly scheduled major maintenance | **82** | 150 – 164 |
| Mine capital | Capital related to mining equipment and land purchases | **—** | 1 – 2 |
| **Total sustaining capital** | | **100** | **200 – 225** |
| Productivity capital | Projects to improve power production efficiency and corporate improvement initiatives | **1** | 3 – 7 |
| **Total sustaining and productivity capital** | | **101** | **203 – 232** |

*(1) As at June 30, 2021.*
*(2) Includes hydro life extension expenditures.*

Significant planned major outages at TransAlta's operated units for the remainder of 2021 include the following:

- Major maintenance turnaround at Keephills Unit 3 is planned to begin at the end of the third quarter;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on major component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for Centralia, which is scheduled during a period of dispatch optimization, is estimated as follows for 2021:

| | Alberta Thermal | Gas and renewables | Lost to date[1] |
|---|---|---|---|
| GWh lost | 1,700 - 1,800 | 500 - 600 | 1,037 |

*(1) As at June 30, 2021.*

## Segmented Comparable Results

Segmented cash flow generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, payments on lease liabilities and provisions. This is the cash flow available to pay our interest and cash taxes, make distributions to our non-controlling partners and pay dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

The table below shows the segmented cash flow generated by each of our segments:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Segmented cash flow**(1) | | | | |
| Hydro | **90** | 27 | **162** | 50 |
| Wind and Solar | **50** | 57 | **119** | 129 |
| North American Gas | **26** | 25 | **59** | 54 |
| Australian Gas | **26** | 29 | **58** | 57 |
| Alberta Thermal(2) | **26** | 21 | **43** | 43 |
| Centralia(2) | **4** | 20 | **13** | 48 |
| **Generation segmented cash flow** | **222** | 179 | **454** | 381 |
| Energy Marketing | **35** | 30 | **80** | 48 |
| Corporate(3) | **(29)** | (18) | **(40)** | (51) |
| **Total segmented cash flow** | **228** | 191 | **494** | 378 |

*(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Please refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.*
*(2) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.*
*(3) Includes gains and losses on the total return swap.*

Segmented cash flow generated by the business for the three and six months ended June 30, 2021, increased by $37 million and $116 million, respectively, compared to the same periods in 2020. The increase was largely due to strong results from the Alberta Electricity Portfolio through optimizing assets during periods of higher realized pricing and favourable short-term trading within Energy Marketing. This was partially offset by major maintenance costs associated with conversion to gas outages at Alberta Thermal and higher fuel and purchased power costs at Centralia for acquiring higher-priced power to fulfil our contractual obligations during planned and unplanned outages during periods of higher merchant pricing. In Corporate costs, we realized a net loss of $2 million and a net gain of $5 million, respectively, for the three and six months ended June 30, 2021, from the total return swap on our share-based payment plans, whereas in the same periods last year we realized a net gain of $3 million and a net loss of $8 million. In addition, Corporate costs were lower on a year-to-date basis compared to the same period in 2020 due to the receipt of $8 million in CEWS funding.

For the three and six months ended June 30, 2021, approximately 63 per cent and 62 per cent, respectively, of our generation segmented cash flows were generated by renewable resources, compared to 47 percent for the same periods in 2020.

## Hydro

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)** | **926** | 926 | **926** | 926 |
| **Availability (%)** | **93.2** | 97.0 | **92.6** | 95.4 |
| Alberta Hydro Assets (GWh)(1) | **392** | 508 | **712** | 814 |
| Other Hydro Assets (GWh)(1) | **162** | 161 | **202** | 198 |
| **Total energy production (GWh)** | **554** | 669 | **914** | 1,012 |
| Ancillary service volumes (GWh)(2) | **749** | 717 | **1,498** | 1,589 |
| **Revenues** | | | | |
| Alberta Hydro Assets(1) | **52** | 20 | **91** | 45 |
| Other Hydro Assets and other revenue(1)(2) | **14** | 12 | **20** | 17 |
| Capacity payments(3) | **—** | 15 | **—** | 30 |
| Alberta Hydro Ancillary services(4) | **48** | 8 | **95** | 44 |
| Environmental credits | **1** | 1 | **1** | 1 |
| **Total gross revenues** | **115** | 56 | **207** | 137 |
| Net payment relating to Alberta Hydro PPA(5) | **(1)** | (14) | **(4)** | (57) |
| **Total Revenues** | **114** | 42 | **203** | 80 |
| Fuel and purchased power | **3** | 2 | **4** | 4 |
| **Comparable gross margin** | **111** | 40 | **199** | 76 |
| Operations, maintenance and administration | **14** | 10 | **24** | 19 |
| Taxes, other than income taxes | **1** | 1 | **2** | 2 |
| **Comparable EBITDA** | **96** | 29 | **173** | 55 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **3** | 1 | **4** | 2 |
| Planned major maintenance | **4** | 1 | **8** | 3 |
| **Total sustaining capital expenditures** | **7** | 2 | **12** | 5 |
| Provisions | **(2)** | — | **(2)** | — |
| Decommissioning and restoration costs settled | **1** | — | **1** | — |
| **Hydro cash flow** | **90** | 27 | **162** | 50 |

*(1) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems in Alberta that are not owned by TransAlta Renewables. Other Hydro Assets include our hydro facilities in BC, Ontario and the hydro facilities in Alberta owned by TransAlta Renewables.*
*(2) Other Hydro Assets includes transmission revenues.*
*(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000. The Alberta Hydro PPA expired on Dec. 31, 2020.*
*(4) Ancillary Services as described in the AESO Consolidated Authoritative Document Glossary.*
*(5) The net payment relating to the Alberta PPA in respect of the Alberta Hydro Assets represents the Corporation's financial obligations for notional amounts of energy and Ancillary Services in accordance with the Alberta PPA that expired on Dec. 31, 2020. The amount shown for the three and six months ended June 30, 2021, is related to adjustments for the final payments under the Alberta PPA recorded in the first and second quarters of 2021.*

Availability for the three and six months ended June 30, 2021, decreased compared to the the same periods in 2020, primarily due to higher unplanned outages, an extended planned outage at our Rundle facility and a major planned outage at Bighorn.

Production for the three and six months ended June 30, 2021, decreased by 115 GWh and 98 GWh, respectively, compared to the same periods in 2020, mainly due to lower availability.

Ancillary service volumes for the three months ended June 30, 2021 were consistent with the same period in 2020. For the six months ended June 30, 2021, ancillary service volumes decreased by 91 GWh, compared to the same period in 2020, primarily due to extended icing events at our Bighorn facility, a planned outage at our Rundle facility and due to the AESO procuring less volumes.

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross Revenues per MWh** | | | | |
| Alberta Hydro assets ($/MWh) | **$133** | $39 | **$128** | $55 |
| Alberta Hydro ancillary services ($/MWh) | **$64** | $11 | **$63** | $28 |

For the three and six months ended June 30, 2021, Alberta Hydro assets revenue per MWh of production increased by approximately $94 per MWh and $73 per MWh, respectively, compared to the same periods in 2020 as a result of higher merchant prices in Alberta. For the three and six months ended June 30, 2021, Alberta Hydro ancillary revenue per MWh of production increased by approximately $53 per MWh and $35 per MWh, respectively, compared to the same periods in 2020 as a result of higher merchant pricing in Alberta. For further discussion on the market conditions and pricing, please refer to the 2021 Financial Outlook section and Alberta Electricity Portfolio section of this MD&A.

Comparable EBITDA for the three and six months ended June 30, 2021, increased by $67 million and $118 million, respectively, compared with the same periods in 2020. On Dec. 31, 2020, the PPA for our Alberta Hydro assets expired and effective Jan. 1, 2021, these facilities operate on a merchant basis in the Alberta power market. With strong availability during periods of market volatility, the Corporation was able to capture higher energy and ancillary service revenue and benefited from the elimination of net payment obligations.

Sustaining capital expenditures for the three and six months ended June 30, 2021, increased by $5 million and $7 million, respectively, compared to the same periods in 2020, due to a greater number of outages.

Hydro's cash flow for the three and six months ended June 30, 2021, increased by $63 million and $112 million, respectively, compared with the same periods in 2020, mainly due to higher comparable EBITDA partially offset by increased capital expenditures.

## Wind and Solar

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)(1)** | **1,572** | 1,495 | **1,572** | 1,495 |
| **Availability (%)** | **95.5** | 96.3 | **95.3** | 95.8 |
| Contract production (GWh) | **622** | 677 | **1,450** | 1,472 |
| Merchant production (GWh) | **204** | 260 | **507** | 601 |
| **Total production (GWh)** | **826** | 937 | **1,957** | 2,073 |
| Revenues | **75** | 80 | **171** | 174 |
| Fuel and purchased power | **3** | 4 | **7** | 9 |
| **Comparable gross margin** | **72** | 76 | **164** | 165 |
| Operations, maintenance and administration | **15** | 13 | **28** | 26 |
| Taxes, other than income taxes | **2** | 2 | **5** | 4 |
| **Comparable EBITDA** | **55** | 61 | **131** | 135 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Planned major maintenance | **3** | 3 | **4** | 5 |
| **Total sustaining capital expenditures** | **3** | 3 | **4** | 5 |
| Provisions | **1** | — | **7** | — |
| Principal payments on lease liabilities | **1** | 1 | **1** | 1 |
| **Wind and Solar cash flow** | **50** | 57 | **119** | 129 |

*(1) The 2021 gross installed capacity includes the addition of the WindCharger battery storage facility and our proportionate share of the Skookumchuck wind facility, which were added in the fourth quarter of 2020.*

Availability for the three and six months ended June 30, 2021, were consistent with the same periods in 2020.

Production for the three and six months ended June 30, 2021, decreased by 111 GWh and 116 GWh, respectively, compared to the same periods in 2020. Production was down due to lower wind resources across our entire fleet, which was partially offset by incremental production from the new Skookumchuck facility.

Comparable EBITDA for the three and six months ended June 30, 2021, decreased by $6 million and $4 million, respectively, compared with the same periods in 2020, primarily due to lower production and lower gains on foreign exchange, which was partially offset by the new Skookumchuck facility and higher pricing in Alberta.

Sustaining capital expenditures for the three and six months ended June 30, 2021, were consistent with the same periods in 2020.

Wind and Solar's cash flow for the three and six months ended June 30, 2021, decreased $7 million and $10 million, respectively, compared to the the same periods in 2020, mainly due to lower comparable EBITDA. In addition, for the six months ended June 30, 2021, cash flows further decreased from settlement of provisions related to the transmission line loss rule proceeding.

## North American Gas

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)** | **974** | 974 | **974** | 974 |
| **Availability (%)** | **91.0** | 95.8 | **95.5** | 98.6 |
| Contract production (GWh) | **440** | 452 | **943** | 909 |
| Merchant production (GWh)(1) | **34** | 15 | **103** | 35 |
| Purchased power (GWh)(1) | **(58)** | (66) | **(104)** | (86) |
| **Total production (GWh)** | **416** | 401 | **942** | 858 |
| Revenues | **55** | 53 | **133** | 109 |
| Fuel and purchased power | **18** | 14 | **42** | 27 |
| Carbon compliance | **5** | — | **12** | 1 |
| **Comparable gross margin** | **32** | 39 | **79** | 81 |
| Operations, maintenance and administration | **13** | 12 | **25** | 24 |
| Taxes, other than income taxes | **1** | — | **1** | 1 |
| **Comparable EBITDA** | **18** | 27 | **53** | 56 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **1** | 2 | **2** | 2 |
| Planned major maintenance | **2** | — | **3** | — |
| **Total sustaining capital expenditures** | **3** | 2 | **5** | 2 |
| Provisions and other | **(11)** | — | **(11)** | — |
| **North American Gas cash flow** | **26** | 25 | **59** | 54 |

*(1) Purchased power used for dispatch optimization has been separated from merchant production in the current year. Comparable periods have been adjusted to reflect this change.*

Availability for the three and six months ended June 30, 2021, was lower compared with the same periods in 2020. Lower availability was primarily the result of unplanned outage events at Sarnia. Higher levels of planned outages at other facilities also contributed to lower availability.

Production for the three and six months ended June 30, 2021, increased by 15 GWh and 84 GWh, respectively, compared to the same periods in 2020, mainly due to the Ada facility acquired in May 2020 and higher merchant production at Sarnia, which was partially offset by unplanned outages.

Comparable EBITDA for the three and six months ended June 30, 2021, decreased by $9 million and $3 million, respectively, compared with the same periods in 2020, primarily due to unplanned outage events at Sarnia. The decrease was partially offset by the May 2020 acquisition of the Ada facility and higher realized pricing in Alberta.

Sustaining capital expenditures for the three and six months ended June 30, 2021, increased by $1 million and $3 million, respectively, compared with the same periods in 2020, mainly due to higher planned outages.

North American Gas' cash flow for the three and six months ended June 30, 2021, increased by $1 million and $5 million, respectively, compared to the same periods in 2020 as lower comparable EBITDA and higher sustaining capital was more than offset by changes in provisions recognized in the period.

## Australian Gas

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)** | **450** | 450 | **450** | 450 |
| **Availability (%)** | **92.8** | 94.3 | **91.9** | 93.1 |
| **Contract production (GWh)** | **415** | 448 | **839** | 919 |
| Revenues | **41** | 39 | **84** | 78 |
| Fuel and purchased power | **2** | 1 | **3** | 3 |
| **Comparable gross margin** | **39** | 38 | **81** | 75 |
| Operations, maintenance and administration | **8** | 9 | **18** | 16 |
| **Comparable EBITDA** | **31** | 29 | **63** | 59 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **1** | — | **1** | — |
| Planned major maintenance | **4** | — | **4** | 2 |
| **Total sustaining capital expenditures** | **5** | — | **5** | 2 |
| **Australian Gas cash flow** | **26** | 29 | **58** | 57 |

Availability for the three and six months ended June 30, 2021, decreased slightly compared to the same periods in 2020, mainly due to unplanned outages.

Production for the three and six months ended June 30, 2021, decreased compared with the same periods in 2020, mainly due to a change in customer loads. Changes in production do not have a significant financial impact as our contracts are structured as capacity payments with customer supplied fuel or a passthrough of fuel costs.

Comparable EBITDA for the three and six months ended June 30, 2021, increased by $2 million and $4 million, respectively, compared with the same periods in 2020. The increase was mainly due to the strengthening of the Australian dollar relative to the Canadian dollar.

Sustaining capital expenditures for the three and six months ended June 30, 2021, increased by $5 million and $3 million, respectively, compared with the same periods in 2020. The increase was mainly due to timing of planned major maintenance.

Australian Gas' cash flow for the three months ended June 30, 2021, decreased by $3 million, compared with the same period in 2020, mainly due to higher sustaining capital expenditures partially offset by higher comparable EBITDA. For the six months ended June 30, 2021, cash flow was consistent with the same period in 2020, with higher comparable EBITDA offset by higher capital expenditures.

## Alberta Thermal[1]

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)[2]** | **2,866** | 3,229 | **2,866** | 3,229 |
| **Availability (%)** | **82.0** | 91.3 | **80.9** | 90.1 |
| Contract production (GWh) | **—** | 1,302 | **—** | 2,840 |
| Merchant production (GWh) | **2,386** | 849 | **4,494** | 2,284 |
| **Total production (GWh)[3]** | **2,386** | 2,151 | **4,494** | 5,124 |
| Revenues | **223** | 141 | **407** | 333 |
| Fuel and purchased power | **75** | 50 | **149** | 127 |
| Carbon compliance | **37** | 35 | **80** | 79 |
| **Comparable gross margin** | **111** | 56 | **178** | 127 |
| Operations, maintenance and administration | **33** | 33 | **63** | 66 |
| Taxes, other than income taxes | **4** | 3 | **8** | 7 |
| Net other operating income | **(11)** | (10) | **(21)** | (20) |
| **Comparable EBITDA** | **85** | 30 | **128** | 74 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **3** | 3 | **6** | 4 |
| Mine capital | **—** | 1 | **—** | 2 |
| Planned major maintenance | **30** | 6 | **50** | 20 |
| **Total sustaining capital expenditures** | **33** | 10 | **56** | 26 |
| Productivity capital | **—** | 1 | **—** | 1 |
| **Total sustaining and productivity capital** | **33** | 11 | **56** | 27 |
| Provisions | **24** | (8) | **25** | (8) |
| Principal payments on lease liabilities | **—** | 3 | **1** | 7 |
| Decommissioning and restoration costs settled | **2** | 3 | **3** | 5 |
| **Alberta Thermal cash flow** | **26** | 21 | **43** | 43 |

*(1) The Canadian Coal segment was renamed Alberta Thermal in the third quarter of 2020.*
*(2) All periods include 406 MW for Sundance Unit 5. The unit was initially temporarily mothballed, however on July 29, 2021, the Corporation has provided notice to the AESO of its intention to retire the coal -fired unit on Nov. 1, 2021. Sheerness Unit 2's capacity was increased in 2020 following a generator rewind and final testing. Sundance Unit 3's 368 MW was included in 2020's gross installed capacity until it was retired in the third quarter of 2020.*
*(3) Estimated production generated from gas fuel source for three and six months ended June 30, 2021 were 1,489 GWh and 2,472 GWh, respectively (2020 - 840 GWh and 1,758 GWh).*

Availability for the three and six months ended June 30, 2021, decreased compared with the same periods in 2020, as a result of the Keephills Unit 2 conversion. In addition, the fleet experienced higher derates and unplanned outages.

Production for the three months ended June 30, 2021, increased by 235 GWh, compared to the same period in 2020, mainly due to higher dispatching of our facilities. Production for the six months ended June 30, 2021 decreased by 630 GWh, compared to the same period in 2020, due to portfolio optimization activities.

Revenue for the three and six months ended June 30, 2021, increased by $82 million and $74 million, respectively, compared to the same periods in 2020, mainly due to higher realized prices within the Alberta market.

| | 3 Months Ended June 30, | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Economic hedge position (percentage)[1] | **71** | 100 | **73** | 100 |
| Spot power price average per MWh | **$105** | $30 | **$100** | $48 |
| Realized power prices per MWh[2] | **$93** | $66 | **$91** | $65 |
| Natural gas price (AECO) per GJ | **$2.93** | $1.89 | **$2.95** | $1.91 |
| Fuel and purchased power per MWh | **$31** | $23 | **$33** | $25 |
| Carbon compliance per MWh | **$16** | $16 | **$18** | $15 |

*(1) Represents the percentage of production sold forward at the end of the reporting period for the Alberta Thermal assets.*
*(2) Realized power prices is the average price realized as a result of the Corporation's commercial contracted sales and portfolio optimization activities divided by total GWh produced.*

In the three and six months ended June 30, 2021, the realized power prices per MWh of production increased by $27 per MWh and $26 per MWh, respectively, compared with the same periods in 2020, primarily due to the optimization of production during periods of favourable pricing. The realized prices include gains or losses from hedging positions that are entered into to mitigate the impact of unfavourable market pricing.

In the three and six months ended June 30, 2021, the fuel and purchased power costs per MWh of production increased by $8 per MWh and $8 per MWh, respectively, compared to the same periods in 2020. Costs per MWh increased due to higher gas pricing, higher transmission costs and fixed coal costs spread over fewer volumes resulting in increased costs per MWh.

In the three months ended June 30, 2021, carbon compliance costs per MWh of production was consistent with the same period in 2020. For the six months ended June 30, 2021, carbon compliance costs increased by $3 per MWh, compared with the same period in 2020. Carbon compliance costs increased in 2021 primarily due to an increase in carbon costs from $30/tonne to $40/tonne. This was partially offset by changes in fuel ratios as we increased our natural gas combustion versus coal. This effectively lowered our GHG compliance costs as natural gas combustion produces fewer GHG emissions than coal combustion.

OM&A costs for the three months ended June 30, 2021, were consistent with the same period in 2020. OM&A costs for the six months ended June 30, 2021, were $3 million lower, compared with the same period in 2020. The decrease was due to planned reductions resulting from our transition off-coal plan and conversion to gas strategy.

Comparable EBITDA for the three and six months ended June 30, 2021, increased by $55 million and $54 million, compared with the same periods in 2020. Higher availability during periods of tight market conditions and higher Alberta pricing was partially offset by increases in fuel and carbon compliance costs.

For the three and six months ended June 30, 2021, sustaining and productivity capital expenditures increased by $22 million and $29 million, respectively, compared to the same periods in 2020, mainly due to the major maintenance costs associated with conversion to gas outages at our coal facilities.

Alberta Thermal's cash flow for the three months ended June 30, 2021, increased by $5 million, compared to the same period in 2020, due to higher comparable EBITDA and lower lease payments, which was partially offset by settlement of provisions. For the six months ended June 30, 2021, cash flow was consistent with the same period in 2020, as higher comparable EBITDA and lower lease payments were offset by higher higher sustaining capital spend and settlement of provisions.

## Centralia[1]

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Gross installed capacity (MW)** [2] | **670** | 1,340 | **670** | 1,340 |
| Availability (%) | **15.4** | 44.6 | **50.8** | 60.4 |
| **Adjusted availability (%)**[3] | **46.0** | 79.1 | **66.2** | 86.1 |
| Contract sales volume (GWh) | **830** | 829 | **1,650** | 1,659 |
| Merchant sales volume (GWh) | **96** | — | **1,246** | 1,271 |
| Purchased power (GWh) | **(835)** | (829) | **(1,813)** | (1,824) |
| **Total production (GWh)** | **91** | — | **1,083** | 1,106 |
| Revenues | **80** | 61 | **180** | 179 |
| Fuel and purchased power | **53** | 17 | **127** | 85 |
| **Comparable gross margin** | **27** | 44 | **53** | 94 |
| Operations, maintenance and administration | **12** | 15 | **25** | 31 |
| Taxes, other than income taxes | **1** | 2 | **2** | 3 |
| **Comparable EBITDA** | **14** | 27 | **26** | 60 |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **—** | 1 | **—** | 2 |
| Planned major maintenance | **12** | 5 | **13** | 7 |
| **Total sustaining capital expenditures** | **12** | 6 | **13** | 9 |
| Productivity capital | **—** | — | **—** | — |
| **Total sustaining and productivity capital** | **12** | 6 | **13** | 9 |
| Provisions | **(4)** | — | **(4)** | — |
| Decommissioning and restoration costs settled | **2** | 1 | **4** | 3 |
| **Centralia cash flow** | **4** | 20 | **13** | 48 |

*(1) The US Coal segment was renamed Centralia in the third quarter of 2020.*
*(2) Centralia Unit 1 was retired from services in the first quarter of 2021.*
*(3) Adjusted for dispatch optimization.*

Adjusted availability for the three and six months ended June 30, 2021, decreased compared to the same periods in 2020, due to higher planned and unplanned outages and due to the retirement of Centralia Unit 1 during the first quarter of 2021.

Production for the three months ended June 30, 2021, was higher compared to the same period in 2020, due to higher merchant pricing. Production for the six months ended June 30, 2021, was consistent with the same period in 2020, as higher pricing and lower dispatch optimization was offset by the retirement of Centralia Unit 1 and lower availability.

Fuel and purchased power for the three and six months ended June 30, 2021, increased by $36 million and $42 million, respectively, due to planned and unplanned outages necessitating power purchases during higher merchant pricing to meet contractual obligations, which was partially offset by lower fuel costs.

OM&A costs for the three and six months ended June 30, 2021, decreased by $3 million and $6 million, respectively, compared with the same periods in 2020, due to the retirement of Centralia Unit 1 and enhanced cost controls.

Comparable EBITDA for the three and six months ended June 30, 2021, decreased by $13 million and $34 million, respectively, compared to the same periods in 2020, primarily due to outages occurring during periods of higher merchant pricing partially offset by lower OM&A costs.

Sustaining capital expenditures for the three and six months ended June 30, 2021, were $6 million and $4 million higher, respectively, compared with the same periods in 2020, mainly due to the timing of planned major maintenance.

Centralia's cash flow for the three and six months ended June 30, 2021, decreased by $16 million and $35 million, respectively, compared to the the same periods in 2020, mainly due to lower comparable EBITDA and higher sustaining capital expenditures, partially offset by increases in provisions for settlements.

## Energy Marketing

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Revenues and comparable gross margin | **34** | 34 | **87** | 56 |
| Operations, maintenance and administration | **7** | 6 | **17** | 15 |
| **Comparable EBITDA** | **27** | 28 | **70** | 41 |
| **Deduct:** | | | | |
| Provisions and other | **(8)** | (2) | **(10)** | (7) |
| **Energy Marketing cash flow** | **35** | 30 | **80** | 48 |

Comparable EBITDA for the three months ended June 30, 2021, was consistent to the same period in 2020. Comparable EBITDA for the six months ended June 30, 2021, increased by $29 million, compared to the same period in 2020, due to favourable short-term trading of both physical and financial power and gas products across all North American markets.

Energy Marketing's cash flow for the three and six months ended June 30, 2021, increased by $5 million due to changes in emissions obligations and prepaid balances for transmission rights. Energy Marketing's cash flow for the six months ended June 30, 2021, increased by $32 million, compared to the the same period in 2020, mainly due to higher comparable EBITDA and changes in emissions obligations and prepaid balances for transmission rights.

## Corporate

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Operations, maintenance and administration | **24** | 14 | **32** | 43 |
| **Comparable EBITDA** | **(24)** | (14) | **(32)** | (43) |
| **Deduct:** | | | | |
| **Sustaining capital:** | | | | |
| Routine capital | **3** | 3 | **5** | 6 |
| **Total sustaining capital expenditures** | **3** | 3 | **5** | 6 |
| Productivity capital | **1** | — | **1** | — |
| **Total sustaining and productivity capital expenditures** | **4** | 3 | **6** | 6 |
| Principal payments on lease liabilities | **1** | 1 | **2** | 2 |
| **Corporate cash flow** | **(29)** | (18) | **(40)** | (51) |

Corporate overhead costs for the three months ended June 30, 2021, increased by $10 million, compared to the same period in 2020, primarily due to realized losses from the the total return swap, additional legal fees and dispute settlement costs. Corporate overhead costs for the six months ended June 30, 2021, decreased by $11 million, compared to the same period in 2020, primarily due to the receipt of CEWS funding and realized gains from the total return swap, partially offset by higher legal fees, dispute settlement costs and higher staffing costs. A portion of the settlement costs of our employee share-based payment plans is hedged by entering into total return swaps, which are cash settled every quarter.

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| **Supplemental disclosure** | **2021** | 2020 | **2021** | 2020 |
| Corporate cash flow | **(29)** | (18) | **(40)** | (51) |
| Total return swap (gains) losses | **2** | (3) | **(5)** | 8 |
| CEWS | **—** | — | **(8)** | — |
| **Adjusted Corporate cash flow** | **(27)** | (21) | **(53)** | (43) |

Adjusted corporate overhead costs for the three months ended June 30, 2021, increased by $6 million, compared to the same period in 2020 due to higher legal fees and incentive payments. For the six months ended June 30, 2021, adjusted corporate overhead costs increased by $10 million, compared to the same period in 2020, due to higher incentive costs, higher legal fees for settlement of outstanding legal issues and an increase in staffing costs. Staffing costs increased due to additional headcount and staff reorganization to centralize services to support growth initiatives. As previously committed, the CEWS funding was used to support the incremental employment within the Corporation.

## Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of earnings (loss) for the three and six months ended June 30, 2021 and 2020. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We evaluate our performance and the performance of our business segments using a variety of measures to provide management and investors with an understanding of our financial position and results. Certain financial measures discussed in this MD&A are not defined under IFRS, are not standard measures under IFRS and, therefore, should not be considered in isolation or as an alternative to, or to be more meaningful than, net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Comparable EBITDA, deconsolidated comparable EBITDA, deconsolidated comparable EBITDA by segment, FFO, deconsolidated FFO, FCF, total net debt, total consolidated net debt, adjusted net debt, deconsolidated net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. Please refer to the reconciliation of Non-IFRS Measures, Segmented Comparable Results, Selected Quarterly Information, Key Financial Ratios and Financial Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

## Reconciliation of Non-IFRS Measures

Each business segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

### Comparable EBITDA

EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, under comparable EBITDA we reclassify certain transactions to facilitate the discussion of the performance of our business:

- Comparable EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.
- 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.
- We also reclassify the depreciation on our mining equipment from fuel, carbon compliance and purchased power to reflect the actual cash cost of our business in our comparable EBITDA.
- The writedown of coal inventory and coal-related parts and materials inventory has been removed from the calculation as it distorts the comparability of comparable EBITDA. Coal-related inventory writedowns are adjustments that are not reflective of our core on-going business results upon conversion to gas. To accelerate our conversion to gas, a decision was made to accelerate the mine shut-down to the end of 2021.
- 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.
- Asset impairments (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.
- 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 comparable EBITDA of Skookumchuck in our total comparable EBITDA. In addition, in the Wind and Solar comparable results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's comparable EBITDA in our total comparable EBITDA as it does not represent our regular power-generating operations.

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Net loss attributable to common shareholders | **(12)** | (60) | **(42)** | (33) |
| Net earnings attributable to non-controlling interests | **30** | 15 | **61** | 22 |
| Preferred share dividends | **10** | 10 | **10** | 20 |
| **Net earnings (loss)** | **28** | (35) | **29** | 9 |
| *Adjustments to reconcile net income to comparable EBITDA* | | | | |
| Income tax expense (recovery) | **44** | (17) | **64** | (15) |
| Gain on sale of assets and other | **(32)** | — | **(33)** | — |
| Foreign exchange gain | **(14)** | (23) | **(21)** | (4) |
| Net interest expense | **60** | 57 | **123** | 119 |
| Equity income | **(2)** | — | **(4)** | — |
| Depreciation and amortization | **123** | 163 | **272** | 319 |
| *Comparable reclassifications* | | | | |
| Decrease in finance lease receivables | **10** | 4 | **20** | 8 |
| Mine depreciation included in fuel cost | **50** | 26 | **105** | 54 |
| Australian interest income | **1** | 1 | **2** | 2 |
| Unrealized mark-to-market (gains) losses | **(13)** | 9 | **(33)** | (46) |
| *Adjustments to earnings to arrive at comparable EBITDA* | | | | |
| Parts and materials inventory writedown | **25** | — | **25** | — |
| Coal inventory writedown | **3** | — | **11** | — |
| Asset impairment (reversal)(1) | **16** | 32 | **45** | (9) |
| Share of adjusted EBITDA from Joint venture(2) | **3** | — | **7** | — |
| **Comparable EBITDA** | **302** | 217 | **612** | 437 |

*(1) The asset impairment for the three months ended June 30, 2021 of $16 million was mainly due to impairment of capital spares and vehicles related to the Highvale mine and coal-burning operations, as well as changes in the decommissioning and restoration liability at the Centralia mine and Sundance Units 1, 2 and 3. The asset impairment for the six months ended June 30, 2021, also includes impairments of $29 million, primarily related to the impairment of the Kaybob project and coal rights, offset by changes in the decommissioning and restoration liability at the Centralia mine and Sundance Units 1, 2 and 3. The asset impairment (reversal) for the three and six months ended June 30, 2020 of $32 million and $9 million, respectively, relates to changes in the decommissioning and restoration liability at the Centralia mine and Sundance Units 1 and 2 as a result of changes in the discount rates due to volatility in the current market.*
*(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.*

## Funds from Operations and Free Cash Flow

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. FCF is a key 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 that FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Cash flow from operating activities[1] | **80** | 121 | **337** | 335 |
| Change in non-cash operating working capital balances | **128** | 30 | **56** | (20) |
| **Cash flow from operations before changes in working capital** | **208** | 151 | **393** | 315 |
| Adjustments | | | | |
| Share of adjusted FFO from joint venture[1] | **—** | — | **4** | — |
| Decrease in finance lease receivable | **10** | 4 | **20** | 8 |
| Parts and materials inventory writedown | **25** | — | **25** | — |
| Coal inventory write-down | **3** | — | **11** | — |
| Other | **4** | 4 | **8** | 8 |
| **FFO** | **250** | 159 | **461** | 331 |
| Deduct: | | | | |
| Sustaining capital | **(66)** | (26) | **(100)** | (55) |
| Productivity capital | **(1)** | (1) | **(1)** | (1) |
| Dividends paid on preferred shares | **(10)** | (10) | **(20)** | (20) |
| Distributions paid to subsidiaries' non-controlling interests | **(32)** | (26) | **(69)** | (45) |
| Principal payments on lease liabilities | **(2)** | (5) | **(4)** | (10) |
| Other | **(1)** | — | **—** | — |
| **FCF** | **138** | 91 | **267** | 200 |
| Weighted average number of common shares outstanding in the period | **270** | 276 | **271** | 276 |
| **FFO per share** | **0.92** | 0.58 | **1.70** | 1.20 |
| **FCF per share** | **0.51** | 0.33 | **0.99** | 0.72 |

*(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.*

The table below bridges our comparable EBITDA to our FFO and FCF:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Comparable EBITDA[1] | **302** | 217 | **612** | 437 |
| Provisions and other | **—** | 10 | **(5)** | 15 |
| Interest expense | **(48)** | (45) | **(99)** | (92) |
| Current income tax expense | **(12)** | (12) | **(35)** | (21) |
| Realized foreign exchange gain (loss) | **(2)** | (6) | **(3)** | 9 |
| Decommissioning and restoration costs settled | **(5)** | (4) | **(8)** | (8) |
| Other cash and non-cash items | **15** | (1) | **(1)** | (9) |
| **FFO** | **250** | 159 | **461** | 331 |
| Deduct: | | | | |
| Sustaining capital | **(66)** | (26) | **(100)** | (55) |
| Productivity capital | **(1)** | (1) | **(1)** | (1) |
| Dividends paid on preferred shares | **(10)** | (10) | **(20)** | (20) |
| Distributions paid to subsidiaries' non-controlling interests | **(32)** | (26) | **(69)** | (45) |
| Principal payments on lease liabilities | **(2)** | (5) | **(4)** | (10) |
| Other | **(1)** | — | **—** | — |
| **FCF** | **138** | 91 | **267** | 200 |

*(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.*

The table below bridges our reported EBITDA of our owned assets to our comparable EBITDA:

| | 3 months ended June 30, 2021 | | | | 6 months ended June 30, 2021 | | | |
|---|---|---|---|---|---|---|---|---|
| | Reported | Adjustments[1] | Joint venture investment[2] | Comparable total | Reported | Adjustments[1] | Joint venture investment[2] | Comparable total |
| Revenues | 619 | 3 | 4 | 626 | 1,261 | — | 9 | 1,270 |
| Fuel, carbon compliance and purchased power | 212 | (54) | — | 158 | 455 | (118) | — | 337 |
| Carbon compliance | 42 | — | — | 42 | 92 | — | — | 92 |
| Gross margin | 365 | 57 | 4 | 426 | 714 | 118 | 9 | 841 |
| Operations, maintenance and administration | 151 | (25) | — | 126 | 256 | (25) | 1 | 232 |
| Asset impairment | 16 | (16) | — | — | 45 | (45) | — | — |
| Taxes, other than income taxes | 8 | — | 1 | 9 | 17 | — | 1 | 18 |
| Net other operating income | (11) | — | — | (11) | (21) | — | — | (21) |
| **Comparable EBITDA** | 201 | 98 | 3 | 302 | 417 | 188 | 7 | 612 |

*(1) Please refer to the reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA table above for details of all adjustments.*
*(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture which was acquired in the fourth quarter of 2020.*

### Alberta Electricity Portfolio Comparable Revenues

A reconciliation of revenues to Alberta Electricity Portfolio comparable revenues is set out below:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Revenues | **619** | 437 | **1,261** | 1,043 |
| *Less: Segments not applicable to the Alberta Electricity Portfolio* | | | | |
| Australian Gas | **(41)** | (39) | **(84)** | (78) |
| Centralia | **(80)** | (61) | **(180)** | (179) |
| Energy Marketing | **(34)** | (34) | **(87)** | (56) |
| Corporate | **(4)** | (1) | **(5)** | 2 |
| **Adjusted Segment Revenues** | **460** | 302 | **905** | 732 |
| *Comparable reclassifications* | | | | |
| Finance lease income | **6** | 1 | **13** | 2 |
| Decrease in finance lease receivables | **10** | 4 | **20** | 8 |
| Unrealized mark-to-market (gains) losses | **(13)** | 7 | **(33)** | (46) |
| *Adjustments to earnings to arrive at comparable revenues for the Alberta Electricity Portfolio* | | | | |
| Revenues from Wind Assets not within Alberta | **(56)** | (70) | **(127)** | (143) |
| Revenues from Hydro Assets not within Alberta | **(10)** | (9) | **(13)** | (13) |
| Revenues from Gas Assets not within Alberta | **(45)** | (47) | **(113)** | (94) |
| **Alberta Electricity Portfolio comparable revenues** | **352** | 188 | **652** | 446 |

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

| | Q3 2020 | Q4 2020 | Q1 2021 | **Q2 2021** |
|---|---|---|---|---|
| Revenues | 514 | 544 | 642 | **619** |
| Comparable EBITDA | 256 | 234 | 310 | **302** |
| FFO | 193 | 161 | 211 | **250** |
| Net loss attributable to common shareholders | (136) | (167) | (30) | **(12)** |
| Net loss per share attributable to common shareholders, basic and diluted(1) | (0.50) | (0.61) | (0.11) | **(0.04)** |

| | Q3 2019 | Q4 2019 | Q1 2020 | Q2 2020 |
|---|---|---|---|---|
| Revenues | 593 | 609 | 606 | 437 |
| Comparable EBITDA | 305 | 243 | 220 | 217 |
| FFO | 244 | 189 | 172 | 159 |
| Net earnings (loss) attributable to common shareholders | 51 | 66 | 27 | (60) |
| Net earnings (loss) per share attributable to common shareholders, basic and diluted(1) | 0.18 | 0.24 | 0.10 | (0.22) |

*(1) Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.*

Reported net earnings, comparable EBITDA and FFO are generally higher in the first and fourth quarters due to higher demand associated with the cold winter months in the markets in which we operate and lower planned outages.

Net earnings attributable to common shareholders has also been impacted by the following variations and events:

- Effective Jan. 1, 2021, many of our Alberta hydro facilities, Keephills Units 1 and 2 and Sheerness began operating on a merchant basis in the Alberta market;
- Revenues declined due to weaker market conditions during the last three quarters of 2020 as a result of the COVID-19 pandemic and low oil prices;
- Sheerness going off-coal has resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Coal inventory writedowns incurred in the first and second quarter of 2021 and third and fourth quarters of 2020;
- Coal-related parts and materials inventory writedowns incurred in the second quarter of 2021;
- The impact of the updated provision estimates for the transmission line loss rule during the first quarter of 2021 and the last three quarters of 2020;
- The unplanned outages at Sarnia in the second quarter of 2021;
- Significant foreign exchange gains in the last three quarters of 2020, which more than offset foreign exchange losses experienced during the first quarter of 2020;
- Gains relating to the Keephills Unit 3 and Genesee Unit 3 swap in the fourth quarter of 2019;
- The effects of impairments and reversals during all periods shown;
- The effects of changes in decommissioning and restoration provisions for retired assets in all periods shown;
- The effects of changes in useful lives of certain assets during the third quarter of 2020 and third quarter of 2019;
- Current tax expense increases since the fourth quarter of 2020, mainly due to the Energy Marketing segment and certain Hydro operations becoming taxable, increased valuation allowances taken on US deferred tax assets along with a decreased deferred tax recovery mainly due to increased revenues in the first and second quarters of 2021; and
- Recognition of $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019.

## Key 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 Comparable EBITDA

| As at | June 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| Period-end long-term debt(1) | **3,091** | 3,361 |
| Exchangeable debentures | **332** | 330 |
| Less: Cash and cash equivalents | **(642)** | (703) |
| Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2) | **671** | 671 |
| Other(3) | **4** | (13) |
| **Adjusted net debt(4)(5)** | **3,456** | 3,646 |
| Comparable EBITDA(5)(6) | **1,102** | 927 |
| **Adjusted net debt to adjusted comparable EBITDA (times)** | **3.1** | 3.9 |

*(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 purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.*
*(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at June 30, 2021 and Dec. 31, 2020.*
*(4) The interest on the tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.*
*(5) 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 trends more readily in comparison with prior periods' results. 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.*
*(6) Last 12 months.*

Our adjusted net debt to adjusted comparable EBITDA ratio was lower than 2020 as a result of strong comparable EBITDA in the first half of 2021, debt repayments and the weakening of the US dollar compared to the Canadian dollar in 2021.

### Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage, excluding the portion of TransAlta Renewables and TransAlta Cogeneration L.P. ("TA Cogen") that are not wholly owned by TransAlta. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. Please also refer to the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

| **As at** | **June 30, 2021** | Dec. 31, 2020 |
|---|---|---|
| Period-end long-term debt(1) | **3,091** | 3,361 |
| Exchangeable debentures | **332** | 330 |
| Less: Cash and cash equivalents | **(642)** | (703) |
| Add: TransAlta Renewables cash and cash equivalents | **240** | 582 |
| Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2) | **671** | 671 |
| Other(3) | **4** | (13) |
| Less: TransAlta Renewables long-term debt | **(667)** | (692) |
| Less: US tax equity financing and South Hedland debt(4) | **(865)** | (905) |
| **Deconsolidated net debt** | **2,164** | 2,631 |
| Comparable EBITDA(5)(6) | **1,102** | 927 |
| Less: TransAlta Renewables comparable EBITDA(5) | **(449)** | (462) |
| Less: TA Cogen comparable EBITDA(5) | **(95)** | (54) |
| Less: comparable EBITDA from equity accounted investments(5)(6) | **(10)** | (3) |
| Add: Dividend from TransAlta Renewables(5) | **151** | 151 |
| Add: Dividend from TA Cogen(5) | **16** | 17 |
| **Deconsolidated comparable EBITDA(5)** | **715** | 576 |
| **Deconsolidated net debt to deconsolidated comparable EBITDA(5) (times)** | **3.0** | 4.6 |

*(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 purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.*
*(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at June 30, 2021 and Dec. 31, 2020.*
*(4) Relates to assets where TransAlta Renewables has economic interests.*
*(5) Last 12 months.*
*(6) Comparable EBITDA includes our share of amounts for Skookumchuck, an equity accounted joint venture.*

We continue to actively reduce our net senior unsecured debt levels to achieve a lower deconsolidated net debt to deconsolidated comparable EBITDA. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio decreased compared with 2020, mainly as a result lower debt balances and stronger comparable EBITDA in the period.

**Deconsolidated Comparable EBITDA by Segment**

Comparable EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated comparable 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 comparable EBITDA to deconsolidated comparable EBITDA by segment results is set out below:

| | **3 months ended June 30, 2021** | | | 3 months ended June 30, 2020 | | |
|---|---|---|---|---|---|---|
| | **TransAlta Consolidated** | **TransAlta Renewables** | **TransAlta Deconsolidated** | TransAlta Consolidated | TransAlta Renewables | TransAlta Deconsolidated |
| Hydro | **96** | **7** | | 29 | 8 | |
| Wind and Solar | **55** | **57** | | 61 | 62 | |
| North American Gas | **18** | **7** | | 27 | 19 | |
| Australian Gas | **31** | **31** | | 29 | 31 | |
| Alberta Thermal | **85** | **—** | | 30 | — | |
| Centralia | **14** | **—** | | 27 | — | |
| Energy Marketing | **27** | **—** | | 28 | — | |
| Corporate | **(24)** | **(5)** | | (14) | (5) | |
| Comparable EBITDA | **302** | **97** | **205** | 217 | 115 | 102 |
| Less: TA Cogen comparable EBITDA | | | **(38)** | | | (10) |
| Less: EBITDA from joint venture investments[1] | | | **(3)** | | | — |
| Add: Dividend from TransAlta Renewables | | | **37** | | | 37 |
| Add: Dividend from TA Cogen | | | **—** | | | 3 |
| Deconsolidated comparable EBITDA | | | **201** | | | 132 |

*(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.*

| | **6 months ended June 30, 2021** | | | 6 months ended June 30, 2020 | | |
|---|---|---|---|---|---|---|
| | **TransAlta Consolidated** | **TransAlta Renewables** | **TransAlta Deconsolidated** | TransAlta Consolidated | TransAlta Renewables | TransAlta Deconsolidated |
| Hydro | **173** | **8** | | 55 | 8 | |
| Wind and Solar | **131** | **132** | | 135 | 136 | |
| North American Gas | **53** | **28** | | 56 | 38 | |
| Australian Gas | **63** | **63** | | 59 | 61 | |
| Alberta Thermal | **128** | **—** | | 74 | — | |
| Centralia | **26** | **—** | | 60 | — | |
| Energy Marketing | **70** | **—** | | 41 | — | |
| Corporate | **(32)** | **(11)** | | (43) | (10) | |
| Comparable EBITDA | **612** | **220** | **392** | 437 | 233 | 204 |
| Less: TA Cogen comparable EBITDA | | | **(63)** | | | (22) |
| Less: EBITDA from joint venture investments[1] | | | **(7)** | | | — |
| Add: Dividend from TransAlta Renewables | | | **75** | | | 75 |
| Add: Dividend from TA Cogen | | | **3** | | | 4 |
| Deconsolidated TransAlta comparable EBITDA | | | **400** | | | 261 |

*(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.*

**Deconsolidated FFO**

The Corporation has set a target to return 10 to 15 per cent of TransAlta's deconsolidated FFO to shareholders as it aligns shareholder returns to the assets held directly at TransAlta. This metric 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. Please refer to the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

| | **3 months ended June 30, 2021** | | | 3 months ended June 30, 2020 | | |
|---|---|---|---|---|---|---|
| | **TransAlta Consolidated** | **TransAlta Renewables** | **TransAlta Deconsolidated** | TransAlta Consolidated | TransAlta Renewables | TransAlta Deconsolidated |
| Cash flow from operating activities | **80** | **79** | | 121 | 71 | |
| Change in non-cash operating working capital balances | **128** | **(19)** | | 30 | (5) | |
| Cash flow from operations before changes in working capital | **208** | **60** | | 151 | 66 | |
| *Adjustments:* | | | | | | |
| Decrease in finance lease receivable | **10** | **—** | | 4 | — | |
| Parts and materials inventory writedown | **25** | **—** | | — | — | |
| Coal inventory write-down | **3** | **—** | | — | — | |
| Share of FFO from joint venture(1) | **—** | **—** | | — | — | |
| Finance and interest income - economic interests | **—** | **(20)** | | — | (10) | |
| AFFO - economic interests | **—** | **30** | | — | 42 | |
| Sustaining capital expenditures - economic interests(2) | **—** | **6** | | — | — | |
| Tax equity distributions - economic interests(2) | **—** | **8** | | — | 6 | |
| Other | **4** | **—** | | 4 | — | |
| **FFO** | **250** | **84** | **166** | 159 | 104 | 55 |
| Dividend from TransAlta Renewables | | | **37** | | | 37 |
| Distributions to TA Cogen's Partner | | | **(6)** | | | (3) |
| Less: Share of adjusted FFO from joint venture | | | **—** | | | — |
| **Deconsolidated TransAlta FFO** | | | **197** | | | 89 |

*(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.*
*(2) During the first quarter of 2021, sustaining capital expenditures and tax equity distributions for TransAlta Renewables' economic interests have been added back to the Adjusted Funds from Operations ("AFFO") to align with the Corporation's calculation of FFO. Prior comparative periods have been adjusted.*

| | 6 months ended June 30, 2021 | | | 6 months ended June 30, 2020 | | |
|---|---|---|---|---|---|---|
| | **TransAlta Consolidated** | **TransAlta Renewables** | **TransAlta Deconsolidated** | TransAlta Consolidated | TransAlta Renewables | TransAlta Deconsolidated |
| Cash flow from operating activities | **337** | **182** | | 335 | 153 | |
| Change in non-cash operating working capital balances | **56** | **(34)** | | (20) | (23) | |
| Cash flow from operations before changes in working capital | **393** | **148** | | 315 | 130 | |
| *Adjustments:* | | | | | | |
| Decrease in finance lease receivable | **20** | **—** | | 8 | — | |
| Parts and materials inventory writedown | **25** | **—** | | — | — | |
| Coal inventory write-down | **11** | **—** | | — | — | |
| Share of FFO from joint venture[1] | **4** | **—** | | — | — | |
| Finance and interest income - economic interests | **—** | **(49)** | | — | (18) | |
| AFFO - economic interests | **—** | **65** | | — | 82 | |
| Sustaining capital expenditures - economic interests[2] | **—** | **6** | | — | 3 | |
| Tax equity distributions - economic interests[2] | **—** | **14** | | — | 12 | |
| Other | **8** | **—** | | 8 | — | |
| **FFO** | **461** | **184** | **277** | 331 | 209 | 122 |
| Dividend from TransAlta Renewables | | | **75** | | | 75 |
| Distributions to TA Cogen's Partner | | | **(17)** | | | (4) |
| Less: Share of adjusted FFO from joint venture | | | **(4)** | | | — |
| **Deconsolidated TransAlta FFO** | | | **331** | | | 193 |

*(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.*
*(2) During the first quarter of 2021, sustaining capital expenditures and tax equity distributions for TransAlta Renewables' economic interests have been added back to the AFFO to align with the Corporation's calculation of FFO. Prior comparative periods have been adjusted.*

# Financial Position

The following table provides a summary of account balances derived from the unaudited interim condensed consolidated statements of financial position as at June 30, 2021 and Dec. 31, 2020:

| As at | June 30, 2021 | Dec. 31, 2020 | Increase (decrease) |
|---|---|---|---|
| **Assets** | | | |
| Cash and cash equivalents | **642** | 703 | (61) |
| Trade and other receivables | **695** | 583 | 112 |
| Prepaid expenses | **58** | 31 | 27 |
| Inventory | **208** | 238 | (30) |
| Assets held for sale | **8** | 105 | (97) |
| Finance lease receivables (long-term) | **201** | 228 | (27) |
| Property, plant, and equipment, net | **5,628** | 5,822 | (194) |
| Right of use assets | **88** | 141 | (53) |
| Intangible assets | **271** | 313 | (42) |
| Others(1) | **1,567** | 1,583 | (16) |
| **Total assets** | **9,366** | 9,747 | (381) |
| **Liabilities and equity** | | | |
| Dividends payable | **37** | 59 | (22) |
| Credit facilities, long-term debt and lease liabilities (current and long-term) | **3,091** | 3,361 | (270) |
| Decommissioning and other provisions (current and long-term) | **644** | 673 | (29) |
| Risk management liabilities (current and long-term) | **330** | 162 | 168 |
| Defined benefit obligation and other long-term liabilities | **256** | 298 | (42) |
| Equity attributable to shareholders | **2,193** | 2,352 | (159) |
| Non-controlling interests | **1,040** | 1,084 | (44) |
| Others(2) | **1,775** | 1,758 | 17 |
| **Total liabilities and equity** | **9,366** | 9,747 | (381) |

*(1) Includes restricted cash, investments, risk management assets, goodwill, deferred income tax assets and other assets.*
*(2) Includes accounts payable and accrued liabilities, income taxes payable, exchangeable securities and contract liabilities.*

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

- Please refer to the Cash Flow section of this MD&A for details on the change in cash during the period.
- Trade and other receivables increased mainly due to higher revenues and timing of cash receipts.
- Prepaid expenses increased mainly due to annual property tax and insurance premium payments.
- Coal Inventory at Alberta Thermal decreased to 446,587 tonnes as at June 30, 2021, compared to 973,298 tonnes at Dec. 31, 2020, resulting in $11 million released from working capital, including the coal inventory writedowns. In addition, a writedown of $25 million was recorded on parts and material inventory related to the Highvale mine and coal operations at our facilities that have been converted to gas. These decreases were partially offset by higher coal stockpiles at Centralia as a result of lower production due to dispatch optimization.
- Assets held for sale decreased as a result of the sale of the Pioneer Pipeline. Please refer to the Significant and Subsequent Events section of this MD&A for further details.
- Finance lease receivables decreased mainly due to scheduled principal receipts.
- Property, plant and equipment ("PP&E") decreased due to depreciation ($338 million), changes in foreign exchange rates ($39 million) and asset impairments ($37 million), which was partially offset by additions ($217 million) relating to assets under construction for the Windrise wind project, boiler conversions, Sundance Unit 5 repowering project and other planned major maintenance expenditures. Please refer to the Significant and Subsequent Events section in this MD&A for more details on the status of the Sundance Unit 5 repowering project.
- Right of use assets decreased due to the 15-year natural gas transportation agreement with Pioneer Pipeline LP being terminated upon the close of the sale of the Pioneer Pipeline, which was accounted for as a lease ($41 million) and depreciation ($10 million).
- Intangible assets decreased due to a $14 million impairment of coal rights and depreciation expense of $27 million.
- Dividends payable decreased due to the timing of the declaration of dividends.

- Credit facilities, long-term debt and lease liabilities decreased due to lower drawings on the credit facilities ($114 million) and debt repayments ($45 million), the termination of the pipeline lease liability ($43 million) and changes in outstanding balances as a result of the weakening of the US dollar ($31 million) and weakening of the Australian closing rates ($33 million).
- Decommissioning and other provisions decreased primarily due to cash settlement of provisions partially offset by additional provisions and accretion of provisions.
- Decreases in net risk management assets and liabilities are primarily attributable to volatility in market prices and contract settlements.
- Defined benefit obligation and other long-term liabilities decreased due to net actuarial gains resulting from increases in actuarial discount rates.
- Equity attributable to shareholders decreased mainly due to net losses for the period ($32 million), net losses on translating net assets of foreign operations ($23 million), and net losses on cash flow hedges ($159 million), partially offset by changes in fair value investments ($39 million) and actuarial gains on defined benefit plans ($38 million).
- Non-controlling interests decreased mainly due to distributions ($67 million) and fair value investment losses on intercompany fair value through other comprehensive income ("FVOCI") investments ($39 million), partially offset by net earnings attributable to non-controlling interests ($61 million).

## Cash Flows

The following reconciles TransAlta's opening cash and cash equivalents to closing cash and cash equivalents:

| | **6 months ended June 30** | | Increase |
|---|---|---|---|
| | **2021** | 2020 | (decrease) |
| Cash and cash equivalents, beginning of period | **703** | 411 | 292 |
| Provided by (used in): | | | |
| Operating activities | **337** | 335 | 2 |
| Investing activities | **(121)** | (204) | 83 |
| Financing activities | **(273)** | (290) | 17 |
| Translation of foreign currency cash | **(4)** | 5 | (9) |
| Cash and cash equivalents, end of period | **642** | 257 | 385 |

Cash provided by operating activities for the six months ended June 30, 2021, was consistent with the same period in 2020 primarily due to higher revenues being realized in Alberta on the merchant assets, partially offset by higher fuel and purchased power and OM&A costs as we transition off coal.

Cash used in investing activities for the six months ended June 30, 2021, decreased compared with the same period in 2020, largely due to:

- proceeds on the sale of Pioneer Pipeline ($128 million);
- no acquisitions in 2021, whereas 2020 had the Ada acquisition ($37 million); and
- partially offset by increased cash spent on construction activities ($70 million).

Cash used in financing activities for the six months ended June 30, 2021, decreased compared with the same period in 2020, largely due to:

- lower common share repurchases under the NCIB ($15 million);
- proceeds on issuing common shares from the exercise of stock options ($8 million);
- lower realized losses ($8 million) on financial instruments;
- changes in working capital related to financing activities ($13 million); and
- partially offset by increased distributions paid to subsidiaries' non-controlling interests ($25 million).

# Financial Capital

## Capital Structure

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

| As at | June 30, 2021 | | Dec. 31, 2020 | |
|---|---|---|---|---|
| | **$** | **%** | $ | % |
| **TransAlta Corporation** | | | | |
| **Net senior unsecured debt** | | | | |
| Recourse debt - CAD debentures | **251** | **4** | 249 | 3 |
| Recourse debt - US senior notes | **860** | **13** | 886 | 13 |
| Credit facilities | **—** | **—** | 114 | 2 |
| Other | **4** | **—** | 7 | — |
| Less: cash and cash equivalents | **(402)** | **(6)** | (121) | (2) |
| Less: Other cash and liquid assets[1] | **4** | **—** | (13) | — |
| **Net senior unsecured debt** | **717** | **11** | 1,122 | 16 |
| **Other debt liabilities** | | | | |
| Exchangeable debentures | **332** | **5** | 330 | 5 |
| Non-recourse debt | **381** | **6** | 385 | 6 |
| Lease liabilities | **62** | **1** | 112 | 2 |
| **Total net debt - TransAlta Corporation** | **1,492** | **23** | 1,949 | 29 |
| **TransAlta Renewables** | | | | |
| **Net TransAlta Renewables reported debt** | | | | |
| Non-recourse debt | **645** | **10** | 670 | 10 |
| Lease liabilities | **22** | **—** | 22 | — |
| Less: cash and cash equivalents | **(240)** | **(4)** | (582) | (9) |
| **Debt on TransAlta Renewables Economic Investments** | | | | |
| US tax equity financing[2] | **126** | **2** | 134 | 2 |
| Non-recourse debt[3] | **739** | **12** | 782 | 11 |
| **Total net debt - TransAlta Renewables** | **1,292** | **20** | 1,026 | 14 |
| **Total consolidated net debt[4]** | **2,784** | **43** | 2,975 | 43 |
| Non-controlling interests | **1,040** | **16** | 1,084 | 16 |
| Exchangeable preferred securities[5] | **400** | **6** | 400 | 6 |
| Equity attributable to shareholders | | | | |
| Common shares | **2,901** | **45** | 2,896 | 43 |
| Preferred shares | **942** | **15** | 942 | 14 |
| Contributed surplus, deficit and accumulated other comprehensive income | **(1,650)** | **(25)** | (1,486) | (22) |
| **Total capital** | **6,417** | **100** | 6,811 | 100 |

*(1) Includes principal portion of OCP restricted cash and fair value asset 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$800 million senior secured notes.*
*(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in these amounts.*
*(5) Exchangeable preferred securities are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.*

The Corporation continues to maintain a strong financial position in part due to our long-term contracts and hedged positions. At quarter end, we had access to $2.0 billion in liquidity including $642 million in cash and cash equivalents.

We have access to additional capital through potential project financings of existing assets that are currently unencumbered. Between 2021 and 2023, we have $820 million of debt maturing, including $500 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the senior notes maturing in 2022.

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

| As at June 30, 2021 | Facility size | Utilized: Outstanding letters of credit[1] | Utilized: Actual drawings | Available capacity | Maturity date |
|---|---|---|---|---|---|
| **TransAlta Corporation** | | | | | |
| Committed syndicated bank facility[2] | 1,250 | 470 | — | 780 | Q2 2025 |
| Canadian committed bilateral credit facilities | 240 | 189 | — | 51 | Q2 2023 |
| **TransAlta Renewables** | | | | | |
| Committed credit facility[2] | 700 | 105 | — | 595 | Q2 2025 |
| **Total** | **2,190** | **764** | **—** | **1,426** | |

*(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 June 30, 2021, we provided cash collateral of $50 million.*
*(2) TransAlta has letters of credit of $97 million and TransAlta Renewables has letters of credit of $105 million issued from uncommitted demand facilities. These obligations are backstopped and reduce the available capacity on the committed credit facilities.*

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

| As at | Aug. 9, 2021 | June 30, 2021 | Dec. 31, 2020 |
|---|---|---|---|
| | **Number of shares** *(millions)* | | |
| **Common shares issued and outstanding, end of period** | **271.0** | **271.0** | 269.8 |
| Preferred shares | | | |
| Series A[1] | 9.6 | **9.6** | 10.2 |
| Series B[1] | 2.4 | **2.4** | 1.8 |
| Series C | 11.0 | **11.0** | 11.0 |
| 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) On March 18, 2021, the Corporation announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices.*
*(2) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares on Oct. 30, 2020. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.*

*Non-Controlling Interests*
As at June 30, 2021, we own 60.1 per cent (June 30, 2020 – 60.2 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables' Dividend Reinvestment Plan ("DRIP"). We do not participate in this plan. In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends. Any future dividends will be paid in cash.

We also own 50.01 per cent of TA Cogen (June 30, 2020 - 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel generating facility (Sheerness).

Reported earnings attributable to non-controlling interests for the three and six months ended June 30, 2021, was $30 million and $61 million, an increase of $15 million and $39 million, respectively, compared to the same periods in 2020. Earnings from TA Cogen for the three and six months ended June 30, 2021, increased compared with the same periods in 2020 due to higher prices in the Alberta market.

For the three months ended June 30, 2021, net earnings from TransAlta Renewables decreased primarily due to unplanned outages, lower foreign exchange gains, partially offset by higher finance income from investments in subsidiaries of TransAlta and no fair value losses recognized in the current period as the Preferred Shares Tracking the Amortizing Term Loan were redeemed on Oct. 23, 2020. For the six months ended June 30, 2021, net earnings increased at TransAlta Renewables primarily due to higher finance income from investments in subsidiaries of

TransAlta, no fair value losses recognized on financial assets as the Preferred Shares Tracking the Amortizing Term Loan were redeemed in the prior year. This was partially offset by the unplanned outages and lower foreign exchange gains recognized in the period.

### Returns to Providers of Capital

*Net Interest Expense*

The components of net interest expense are shown below:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Interest on debt | **40** | 39 | **80** | 82 |
| Interest on exchangeable debentures | **7** | 8 | **14** | 15 |
| Interest on exchangeable preferred shares | **7** | — | **14** | — |
| Interest income | **(3)** | (2) | **(6)** | (5) |
| Capitalized interest | **(3)** | (1) | **(8)** | (2) |
| Interest on lease liabilities | **2** | 2 | **4** | 4 |
| Credit facility fees, bank charges, and other interest | **4** | 5 | **8** | 9 |
| Tax shield on tax equity financing | **—** | — | **1** | — |
| Other | **(1)** | — | **2** | 1 |
| Accretion of provisions | **7** | 6 | **14** | 15 |
| **Net interest expense** | **60** | 57 | **123** | 119 |

Net interest expense for the three and six months ended June 30, 2021, was higher than the same periods in 2020. Interest expense increased in 2021 mainly due to the exchangeable preferred shares that were issued in 2020, and the project financing related to South Hedland obtained in the fourth quarter of 2020, partially offset by an increase in capitalized interest on development projects, the redemption of $400 million medium-term notes in the fourth quarter of 2020 and lower interest on other debt balances due to scheduled repayments.

# Regulatory Updates

Please refer to the Policy and Legal Risks discussion in our 2020 annual MD&A as well as the Corporate Strategy section of this MD&A for further details that supplement the recent developments as discussed below.

## Canada

### Federal Climate Plan

On Dec. 11, 2020, the Government of Canada released its "*A Healthy Environment and a Healthy Economy*" climate plan that outlines how the federal government intends to use policies, regulations and funding to achieve Canada's Paris Agreement emissions reduction target. TransAlta continues to engage with governments to mitigate risks and identify opportunities within the new federal plan. Please refer to the Corporate Strategy section of this MD&A for further details.

### Clean Fuel Regulation

On Dec. 19, 2020, the Canadian federal government published its draft version of the CFR. This started a 75-day obligatory public consultation period that ended on March 4, 2021 pursuant to which the public was able to submit comments. The federal government also announced the CFR would only regulate liquid transportation fuels, removing gaseous and solid fuels from regulation thereby limiting the impact on the electricity sector. The CFR is scheduled to be finalized in December 2021 and come into force on Dec. 1, 2022.

### Federal Carbon Pricing on GHG

On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the federal government implemented a national price on GHG emissions. On Jan. 1, 2019, the GGPPA's backstop mechanisms came into force in provinces and territories that did not have an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system. The backstop mechanism has two components: a carbon levy for small emitters ("Carbon Tax") and regulation for large emitters called the Output-Based Pricing Standard ("OBPS"). The Carbon Tax sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources. The carbon price is also the OBPS compliance price for carbon obligations.

On Feb. 12, 2021, the federal government began planning for a 2022 review of the OBPS and other aspects of the GGPPA. TransAlta will actively engage in this process as any changes to the OBPS will likely influence provincial carbon pricing systems in the future.

On June 5, 2021, the federal government published draft amendments to the GGPPA regulations clarifying the treatment of boilers. If adopted, this clarification will provide greater certainty regarding the treatment of gas-fired generating facilities under the OBPS.

#### Ontario Transition to Provincial Emission Performance Standard ("EPS")

In the fall of 2020, the federal government confirmed the EPS met the requirements of the GGPPA permitting Ontario to transition from the OBPS to the EPS. Ontario will transition to the EPS on Jan. 1, 2022. The transition to the EPS represents no material risk to TransAlta's business in Ontario. TransAlta will continue to submit compliance reports to the federal government under the OBPS until the implementation of the EPS.

#### Net-Zero Emissions Accountability Act

The federal government has committed to a net-zero emission target by 2050. The *Canadian Net-Zero Emissions Accountability Act*, which received Royal Assent on June 30, 2021, requires the federal government to set an interim target for 2026 and emission targets for the years 2030, 2035, 2040 and 2045 at least 5 years before the target date. When setting targets, the government will also publish an action plan of measures that it will implement to support the achievement of the target. The federal Department of Finance will provide an annual report on costs of the measures and progress.

### United States

#### President Biden's Updated 2030 Emissions Reduction Commitment

On April 22, 2021, during a climate summit hosted by President Biden, the President committed to reduce US GHG emissions by 50 to 52 per cent below 2005 levels by 2030.

#### President Biden Executive Order on Climate Related Financial Risk

On May 25, 2021, President Biden's administration published an Executive Order that tasks the US Secretary of Treasury with the responsibility to determine the federal government and the economy's financial exposure to climate change impacts and to develop strategy documents outlining approaches to deal with the impacts of climate change. This work will likely lead to more formalized and consistent climate risk reporting by public and private sector entities.

#### Washington State Cap and Trade

On May 17, 2021, Governor Inslee signed into law Washington State's cap and trade law. This law will cover entities that emit over 25,000 $tCO_2e$ per year. The regulation is expected to start in 2023 and will link with the California and Quebec Western Climate Initiative Cap and Trade system in 2026. TransAlta's Centralia facility will be exempt from the cap and trade system until it closes in 2025 as per our previous agreement with the State of Washington.

## Other Consolidated Analysis

### Commitments

Certain commitments disclosed in the Other Consolidated Analysis section of the 2020 Annual Integrated Report are based on variable pricing; any material updates to contracts containing variable pricing are discussed below. Please also refer to the Other Consolidated Analysis section of the 2020 Annual Integrated Report for a complete listing of commitments we have incurred either directly or through interests in joint operations.

#### Natural Gas Purchase and Transportation Contracts

As part of the sale of the Pioneer Pipeline, the Corporation entered into a 15-year agreement for an additional 275 TJ per day of natural gas transportation on a firm basis by 2023, representing a new commitment of $439 million over the next 15 years. This agreement replaces, in part, the Corporation's existing 15-year commitment for natural gas transportation for 139 TJ per day on the Pioneer Pipeline, which was terminated on June 30, 2021, and was accounted for as a lease. As a result, the Corporation now has firm gas transportation contracts in place for 400 TJ per day by 2023. Additionally, on June 30, 2021, the Corporation's agreement to purchase 139 TJ per day of natural gas from Tidewater was terminated, which reduces the commitments disclosed at Dec. 31, 2020 by $1.7 billion.

### Contingencies

For the current significant outstanding contingencies, please refer to the Other Consolidated Analysis section of the 2020 Annual MD&A included in the 2020 Annual Integrated Report. Changes to these contingencies during the six months ended June 30, 2021, are included with the Significant and Subsequent Events section of the MD&A and below.

### I. 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. The Corporation commenced an investigation to determine the root cause of each of the three events, which should be completed in the third quarter of 2021. The results of the investigation will help to determine if any liquidated damages are owing and, if so, the quantum.

### II. Transmission Line Loss Rule Proceeding

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and the third and final invoice for $11 million was received in the first quarter of 2021. All invoices have settled as of the second quarter of 2021, which remain subject to true-up invoices expected to be issued by the AESO in Oct. 2021. The impact of the true-up invoices, if any, to the Corporation is not known at this time.

### III. Kaybob 3 Cogeneration Dispute

The Corporation is engaged in a dispute with Energy Transfer Canada ULC, formerly SemCAMS Midstream ULC ("ET Canada") as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing has not yet been scheduled but will likely occur sometime in 2022.

### IV. Fortescue Metals Group Ltd. Dispute

The Corporation has been engaged in a dispute with FMG as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was to start on May 3, 2021 but, on May 2, 2021, the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions.

## 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. There were no material changes in estimates in the quarter, except for the following:

*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 to $231 million as at June 30, 2021 from $282 million as at Dec. 31, 2020.

## Accounting Changes

### Current Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Corporation's audited annual consolidated financial statements for the year ended Dec. 31, 2020, except for the adoption of new standards effective as of Jan. 1, 2021 and the early adoption of standards, interpretations or amendments that have been issued but are not yet effective.

#### Amendments to IAS 16 *Property, Plant and Equipment*: Proceeds before Intended Use

Effective Jan. 1, 2021, the Corporation early adopted amendments to IAS 16 *Property, plant and equipment* ("IAS 16 Amendments"), in advance of its mandatory effective date of Jan. 1, 2022. The Corporation adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendment.

#### IFRS 7 *Financial Instruments:* Disclosures — Interest Rate Benchmark Reform

London Interbank Offered Rate ("LIBOR") is scheduled to be phased out as an interest rate index readily used by corporations for financial instruments by the end of 2021. The International Accounting Standards Board ("IASB") issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Corporation on Jan. 1, 2021.

The Corporation's credit facilities references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at June 30, 2021, there were no drawings under the credit facilities. The Corporation is monitoring the reform and does not expect any material impact.

### Future Accounting Policy and National Instrument Changes

#### Amendments to IAS 1 Presentation of Financial Statements: Material Accounting Policies

On Feb. 12, 2021, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to require entities to disclose their material accounting policy information rather than their significant accounting policies. The amendments are effective for annual periods beginning on or after Jan. 1, 2023, but the Corporation plans to early adopt these amendments for the 2021 annual financial statements.

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

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

The amendments are effective for annual periods beginning on or after Jan. 1, 2023 with early application permitted. The Corporation is currently assessing the potential impact of this amendment on our financial statements.

#### National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure

On May 27, 2021, the Canadian Securities Administrators published the final National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure* ("the Instrument"), effective Aug. 25, 2021 and will apply to reporting issuers for documents filed for a financial year ending on or after Oct. 15, 2021. The Instrument addresses disclosure of non-GAAP financial measures, non-GAAP ratios and other financial measures with the intent to provide clarity and consistency with respect to an issuer's disclosure obligations. The Corporation plans to apply the Instrument on its filings for the year ended Dec. 31, 2021.

For further details and changes in estimates relating to prior years, please refer to Note 3 of the 2020 audited annual consolidated financial statements and Note 2 of the unaudited interim condensed consolidated financial statements.

## Financial Instruments

Please refer to Note 15 of the notes to the 2020 audited annual consolidated financial statements and Note 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2021, 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 on a quarterly basis by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the unaudited interim condensed consolidated financial statements.

At June 30, 2021, Level III instruments had a net asset carrying value of $245 million (Dec. 31, 2020 - $582 million net asset). The decrease during the period is primarily attributable to volatility in market prices and contract settlements. Our risk management profile and practices have not changed materially from Dec. 31, 2020.

# Governance and Risk Management

Please refer to the Governance and Risk Management section of our 2020 Annual Integrated Report and Note 11 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2020. The following factor may contribute to those risks and uncertainties:

### COVID-19 Global Pandemic

During the year, TransAlta has maintained a number of risk mitigation measures introduced in 2020 in response to the COVID-19 pandemic to keep our people safe and to ensure that we are able to remain fully operational and capable of meeting our customer needs.

Overall, we continue to actively monitor the situation and advice from public health officials with a view to responding to changing recommendations and adapting our response and approach as necessary.

# Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the three and six months ended June 30, 2021, the majority of our workforce supporting and executing our ICFR and DC&P worked remotely. There has been minimal impact to the design and performance of our internal controls. Management has reviewed the changes as a result of changes implemented in response to COVID-19 and is reasonably assured that adjustments to process have not materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of 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 Corporation's ICFR.

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

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

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at June 30, 2021, 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 June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| *Unaudited* | **2021** | 2020 | **2021** | 2020 |
| Revenues (Note 4) | **619** | 437 | **1,261** | 1,043 |
| Fuel and purchased power (Note 5) | **212** | 116 | **455** | 309 |
| Carbon compliance | **42** | 35 | **92** | 80 |
| **Gross margin** | **365** | 286 | **714** | 654 |
| Operations, maintenance and administration (Note 5) | **151** | 112 | **256** | 240 |
| Depreciation and amortization | **123** | 163 | **272** | 319 |
| Asset impairment (reversal) (Note 6) | **16** | 32 | **45** | (9) |
| Taxes, other than income taxes | **8** | 8 | **17** | 17 |
| Net other operating income | **(11)** | (10) | **(21)** | (20) |
| **Operating income (loss)** | **78** | (19) | **145** | **107** |
| Equity income | **2** | — | **4** | **—** |
| Finance lease income | **6** | 1 | **13** | 2 |
| Net interest expense (Note 7) | **(60)** | (57) | **(123)** | (119) |
| Foreign exchange gain | **14** | 23 | **21** | 4 |
| Gain on sale of assets and other | **32** | — | **33** | — |
| **Earnings (loss) before income taxes** | **72** | (52) | **93** | (6) |
| Income tax expense (recovery) (Note 8) | **44** | (17) | **64** | (15) |
| **Net earnings (loss)** | **28** | (35) | **29** | 9 |
| | | | | |
| **Net earnings (loss) attributable to:** | | | | |
| TransAlta shareholders | **(2)** | (50) | **(32)** | (13) |
| Non-controlling interests (Note 9) | **30** | 15 | **61** | 22 |
| | **28** | (35) | **29** | 9 |
| | | | | |
| Net loss attributable to TransAlta shareholders | **(2)** | (50) | **(32)** | (13) |
| Preferred share dividends (Note 17) | **10** | 10 | **10** | 20 |
| **Net loss attributable to common shareholders** | **(12)** | (60) | **(42)** | (33) |
| **Weighted average number of common shares outstanding in the period** *(millions)* | **270** | 276 | **271** | 276 |
| **Net loss per share attributable to common shareholders, basic and diluted** | **(0.04)** | (0.22) | **(0.16)** | (0.12) |

*See accompanying notes.*

# Condensed Consolidated Statements of Comprehensive Income (Loss)

*(in millions of Canadian dollars)*

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| *Unaudited* | **2021** | 2020 | **2021** | 2020 |
| **Net earnings (loss)** | **28** | (35) | **29** | 9 |
| **Other comprehensive income (loss)** | | | | |
| Net actuarial gains (loss) on defined benefit plans, net of tax (Note 1B)[(1)] | **1** | (21) | **38** | (15) |
| Gains (losses) on derivatives designated as cash flow hedges, net of tax[(2)] | **—** | (4) | **(1)** | 5 |
| **Total items that will not be reclassified subsequently to net earnings** | **1** | (25) | **37** | (10) |
| Gains (losses) on translating net assets of foreign operations, net of tax | **(24)** | (29) | **(37)** | 67 |
| Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax | **9** | 18 | **14** | (23) |
| Gains (losses) on derivatives designated as cash flow hedges, net of tax[(3)] | **(108)** | 41 | **(131)** | 55 |
| Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(4)] | **(8)** | (24) | **(26)** | (49) |
| **Total items that will be reclassified subsequently to net earnings** | **(131)** | 6 | **(180)** | 50 |
| **Other comprehensive income (loss)** | **(130)** | (19) | **(143)** | 40 |
| **Total comprehensive income (loss)** | **(102)** | (54) | **(114)** | 49 |
| | | | | |
| **Total comprehensive income (loss) attributable to:** | | | | |
| TransAlta shareholders | **(135)** | (41) | **(137)** | 37 |
| Non-controlling interests (Note 9) | **33** | (13) | **23** | 12 |
| | **(102)** | (54) | **(114)** | 49 |

*(1) Net of income tax expense of nil and $11 million for the three and six months ended June 30, 2021 (2020 - $7 million and $5 million recovery).*
*(2) Net of income tax expense of nil for the three and six months ended June 30, 2021 (2020 - nil and $1 million expense).*
*(3) Net of income tax recovery of $28 million and $36 million for the three and six months ended June 30, 2021 (2020 - $11 million and $16 million expense).*
*(4) Net of reclassification of income tax expense of $2 million and $7 million for the three and six months ended June 30, 2021 (2020 - 6 million and $13 million expense).*

*See accompanying notes.*

## Condensed Consolidated Statements of Financial Position

*(in millions of Canadian dollars)*

| *Unaudited* | **June 30, 2021** | Dec. 31, 2020 |
|---|---|---|
| Cash and cash equivalents | **642** | 703 |
| Restricted cash | **54** | 71 |
| Trade and other receivables | **695** | 583 |
| Prepaid expenses | **58** | 31 |
| Risk management assets (Note 10 and 11) | **225** | 171 |
| Inventory (Note 12) | **208** | 238 |
| Assets held for sale | **8** | 105 |
| | **1,890** | 1,902 |
| Investments | **98** | 100 |
| Long-term portion of finance lease receivables | **201** | 228 |
| Risk management assets (Note 10 and 11) | **456** | 521 |
| Property, plant and equipment (Note 13) | | |
| Cost | **13,407** | 13,398 |
| Accumulated depreciation | **(7,779)** | (7,576) |
| | **5,628** | 5,822 |
| Right of use asset (Note 3) | **88** | 141 |
| Intangible assets | **271** | 313 |
| Goodwill | **463** | 463 |
| Deferred income tax assets | **65** | 51 |
| Other assets | **206** | 206 |
| **Total assets** | **9,366** | 9,747 |
| Accounts payable and accrued liabilities | **582** | 599 |
| Current portion of decommissioning and other provisions | **55** | 59 |
| Risk management liabilities (Note 10 and 11) | **237** | 94 |
| Current portion of contract liabilities | **15** | 1 |
| Income taxes payable | **26** | 18 |
| Dividends payable (Note 16 and 17) | **37** | 59 |
| Current portion of long-term debt and lease liabilities (Note 14) | **115** | 105 |
| | **1,067** | 935 |
| Credit facilities, long-term debt and lease liabilities (Note 14) | **2,976** | 3,256 |
| Exchangeable securities (Note 15) | **732** | 730 |
| Decommissioning and other provisions | **589** | 614 |
| Deferred income tax liabilities | **407** | 396 |
| Risk management liabilities (Note 10 and 11) | **93** | 68 |
| Contract liabilities | **13** | 14 |
| Defined benefit obligation and other long-term liabilities (Note 1B) | **256** | 298 |
| Equity | | |
| Common shares (Note 16) | **2,901** | 2,896 |
| Preferred shares | **942** | 942 |
| Contributed surplus | **33** | 38 |
| Deficit | **(1,880)** | (1,826) |
| Accumulated other comprehensive income | **197** | 302 |
| **Equity attributable to shareholders** | **2,193** | 2,352 |
| Non-controlling interests (Note 9) | **1,040** | 1,084 |
| **Total equity** | **3,233** | 3,436 |
| **Total liabilities and equity** | **9,366** | 9,747 |

Significant and subsequent events (Note 3)
Commitments and contingencies (Note 18)

*See accompanying notes.*

# Condensed Consolidated Statements of Changes in Equity

*(in millions of Canadian dollars)*

*Unaudited*

| 6 months ended June 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 earnings (loss) | — | — | — | (32) | — | (32) | 61 | 29 |
| Other comprehensive income (loss): | | | | | | | | |
| Net losses on translating net assets of foreign operations, net of hedges and of tax | — | — | — | — | (23) | (23) | — | (23) |
| Net gain (losses) on derivatives designated as cash flow hedges, net of tax | — | — | — | — | (159) | (159) | 1 | (158) |
| Net actuarial gains on defined benefits plans, net of tax | — | — | — | — | 38 | 38 | — | 38 |
| Intercompany FVOCI investments | — | — | — | — | 39 | 39 | (39) | — |
| Total comprehensive income (loss) | — | — | — | (32) | (105) | (137) | 23 | (114) |
| Common share dividends | — | — | — | (12) | — | (12) | — | (12) |
| Preferred share dividends | — | — | — | (10) | — | (10) | — | (10) |
| Effect of share-based payment plans | 5 | — | (5) | — | — | — | — | — |
| Distributions paid, and payable, to non-controlling interests (Note 9) | — | — | — | — | — | — | (67) | (67) |
| **Balance, June 30, 2021** | **2,901** | **942** | **33** | **(1,880)** | **197** | **2,193** | **1,040** | **3,233** |

| 6 months ended June 30, 2020 | Common shares | Preferred shares | Contributed surplus | Deficit | Accumulated other comprehensive income | Attributable to shareholders | Attributable to non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|
| Balance, Dec. 31, 2019 | 2,978 | 942 | 42 | (1,455) | 454 | 2,961 | 1,101 | 4,062 |
| Net earnings (loss) | — | — | — | (13) | — | (13) | 22 | 9 |
| Other comprehensive income (loss): | | | | | | | | |
| Net gains on translating net assets of foreign operations, net of hedges and tax | — | — | — | — | 44 | 44 | — | 44 |
| Net gains on derivatives designated as cash flow hedges, net of tax | — | — | — | — | 11 | 11 | — | 11 |
| Net actuarial losses on defined benefits plans, net of tax | — | — | — | — | (15) | (15) | — | (15) |
| Intercompany FVOCI investments | — | — | — | — | 10 | 10 | (10) | — |
| Total comprehensive income (loss) | — | — | — | (13) | 50 | 37 | 12 | 49 |
| Common share dividends | — | — | — | (23) | — | (23) | — | (23) |
| Preferred share dividends | — | — | — | (20) | — | (20) | — | (20) |
| Shares purchased under NCIB | (30) | — | — | 9 | — | (21) | — | (21) |
| Changes in non-controlling interests in TransAlta Renewables (Note 9) | — | — | — | 3 | — | 3 | 9 | 12 |
| Effect of share-based payment plans | (4) | — | (10) | — | — | (14) | — | (14) |
| Distributions paid, and payable, to non-controlling interests (Note 9) | — | — | — | — | — | — | (54) | (54) |
| Balance, June 30, 2020 | 2,944 | 942 | 32 | (1,499) | 504 | 2,923 | 1,068 | 3,991 |

*See accompanying notes.*

# Condensed Consolidated Statements of Cash Flows

*(in millions of Canadian dollars)*

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| *Unaudited* | **2021** | 2020 | **2021** | 2020 |
| **Operating activities** | | | | |
| Net earnings (loss) | **28** | (35) | **29** | 9 |
| Depreciation and amortization (Note 19) | **173** | 188 | **377** | 372 |
| Gain on sale of assets (Note 3) | **(32)** | — | **(33)** | — |
| Accretion of provisions (Note 7) | **7** | 6 | **14** | 15 |
| Decommissioning and restoration costs settled | **(5)** | (4) | **(8)** | (8) |
| Deferred income tax expense (recovery) (Note 8) | **32** | (29) | **29** | (36) |
| Unrealized (gain) loss from risk management activities | **(13)** | 7 | **(33)** | (46) |
| Unrealized foreign exchange (gains) losses | **(16)** | (24) | **(25)** | 2 |
| Provisions and contract liability | **(18)** | 9 | **(22)** | 9 |
| Asset impairment (reversal) (Note 6) | **16** | 32 | **45** | (9) |
| Equity income, net of distributions from Joint Ventures | **1** | — | **(1)** | — |
| Other non-cash items | **35** | 1 | **21** | 7 |
| Cash flow from operations before changes in working capital | **208** | 151 | **393** | 315 |
| Change in non-cash operating working capital balances | **(128)** | (30) | **(56)** | 20 |
| **Cash flow from operating activities** | **80** | 121 | **337** | 335 |
| **Investing activities** | | | | |
| Additions to property, plant and equipment (Note 13) | **(119)** | (75) | **(217)** | (147) |
| Additions to intangibles | **(2)** | (3) | **(3)** | (5) |
| Restricted cash | **(2)** | (1) | **15** | 16 |
| Acquisitions, net of cash acquired | **—** | (37) | **—** | (37) |
| Proceeds on the sale of Pioneer Pipeline (Note 3) | **128** | — | **128** | — |
| Proceeds on sale of property, plant and equipment | **—** | 1 | **4** | 1 |
| Realized gains (losses) on financial instruments | **(1)** | 3 | **(3)** | 6 |
| Decrease in finance lease receivable | **10** | 4 | **20** | 8 |
| Increase in loan receivable | **(2)** | (3) | **(2)** | (3) |
| Other | **(13)** | 1 | **(18)** | 4 |
| Change in non-cash investing working capital balances | **(9)** | 1 | **(45)** | (47) |
| **Cash flow used in investing activities** | **(10)** | (109) | **(121)** | (204) |
| **Financing activities** | | | | |
| Net decrease in borrowings under credit facilities (Note 14) | **—** | (8) | **(114)** | (109) |
| Repayment of long-term debt (Note 14) | **(27)** | (27) | **(45)** | (44) |
| Dividends paid on common shares (Note 16) | **(12)** | (12) | **(24)** | (23) |
| Dividends paid on preferred shares (Note 17) | **(10)** | (10) | **(20)** | (20) |
| Net proceeds on issuance of common shares (Note 16) | **8** | — | **8** | — |
| Repurchase of common shares under NCIB (Note 16) | **—** | (10) | **(4)** | (19) |
| Realized gains (losses) on financial instruments | **1** | 3 | **1** | (7) |
| Distributions paid to subsidiaries' non-controlling interests (Note 9) | **(30)** | (23) | **(67)** | (42) |
| Repayment of lease liabilities (Note 14) | **(2)** | (5) | **(4)** | (10) |
| Other | **(1)** | (2) | **(3)** | (2) |
| Change in non-cash financing working capital balances | **—** | — | **(1)** | (14) |
| **Cash flow used in financing activities** | **(73)** | (94) | **(273)** | (290) |
| **Cash flow used in operating, investing, and financing activities** | **(3)** | (82) | **(57)** | (159) |
| **Effect of translation on foreign currency cash** | **(3)** | 1 | **(4)** | 5 |
| **Decrease in cash and cash equivalents** | **(6)** | (81) | **(61)** | (154) |
| **Cash and cash equivalents, beginning of period** | **648** | 338 | **703** | 411 |
| **Cash and cash equivalents, end of period** | **642** | 257 | **642** | 257 |
| Cash income taxes paid | **15** | 8 | **27** | 20 |
| Cash interest paid | **61** | 60 | **112** | 99 |

*See accompanying notes.*

# Notes to Condensed Consolidated Financial Statements

***(Unaudited)***

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

# 1. Accounting Policies

## A. 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 TransAlta Corporation's ("TransAlta" or the "Corporation") 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 Corporation's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation'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 Corporation and the subsidiaries that it controls.

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

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of the Board of Directors on Aug. 9, 2021.

## B. Use of Estimates and Significant Judgments

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. Please refer to Note 2(Z) of the Corporation's most recent audited annual consolidated financial statements for further details. 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.

### Change in Estimates

*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 to $231 million as at June 30, 2021 from $282 million as at Dec. 31, 2020.

# 2. Significant Accounting Policies

## A. Current Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Corporation's audited annual consolidated financial statements for the year ended Dec. 31, 2020, except for the adoption of new standards effective as of Jan. 1, 2021 and the early adoption of standards, interpretations or amendments that have been issued but are not yet effective.

### I. Amendments to IAS 16 Property, Plant and Equipment: Proceeds before Intended Use

Effective Jan. 1, 2021, the Corporation early adopted amendments to IAS 16 Property, plant and equipment ("IAS 16 Amendments"), in advance of its mandatory effective date of Jan. 1, 2022. The Corporation adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendment.

#### II. IFRS 7 Financial Instruments: Disclosures — Interest Rate Benchmark Reform

London Interbank Offered Rate ("LIBOR") is scheduled to be phased out as an interest rate index readily used by corporations for financial instruments by the end of 2021. The International Accounting Standards Board ("IASB") issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Corporation on Jan. 1, 2021.

The Corporation's credit facilities references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at June 30, 2021, there were no drawings under the credit facilities. The Corporation is monitoring the reform and does not expect any material impact.

### B. Future Accounting Policy Changes

#### I. Amendments to IAS 1 Presentation of Financial Statements: Material Accounting Policies

On Feb. 12, 2021, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to require entities to disclose their material accounting policy information rather than their significant accounting policies. The amendments are effective for annual periods beginning on or after Jan. 1, 2023, but the Corporation plans to early adopt these amendments for the 2021 annual financial statements.

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

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

The amendments are effective for annual periods beginning on or after Jan. 1, 2023 with early application permitted. The Corporation is currently assessing the potential impact of this amendment on our financial statements.

### C. Comparative Figures

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

# 3. Significant and Subsequent Events

## A. BHP Nickel West Solar Contract

On July 29, 2021, TransAlta Renewables announced that Southern Cross Energy, a subsidiary of the Corporation and an entity in which TransAlta Renewables owns an indirect economic interest, had reached an agreement to provide BHP Nickel West Pty Ltd. ("BHP") with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Construction activities are scheduled to start in the fourth quarter of 2021 with completion of the projects expected in the second half of 2022. Total construction capital of the project is estimated at approximately AU$73 million. This is the first major growth project agreed under the extended power purchase agreement ("PPA") that was executed in October of 2020. The Corporation continues to actively explore other growth opportunities with BHP.

## B. Sundance Unit 5 Retirement as a Coal-Fired Unit

On July 29, 2021, in accordance with applicable regulatory requirements, the Corporation gave notice to the Alberta Electric System Operator ("AESO") of its intention to retire the currently mothballed coal-fired Sundance Unit 5 effective Nov. 1, 2021 and to terminate the associated transmission service agreement. Under the applicable regulatory rules, a mothball outage can extend no later than 24 months after the commencement of such mothball outage; following which time either the unit must be returned to service, or the transmission service agreement must be terminated (effectively retiring the unit as a coal-fired facility). The AESO had previously granted the extension of the mothball outage for the Sundance Unit 5 mothballed outage to Nov. 1, 2021. As a result, Sundance Unit 5 will not be returning to service as a coal-fired unit.

## C. Keephills Unit 2 and Sundance Unit 6 Conversion to Gas Completions

On July 19, 2021, the Corporation announced the completion of the full conversion of Keephills Unit 2 from thermal coal to natural gas. In February 2021, the Corporation also completed the conversion of Sundance Unit 6. Both Keephills Unit 2 and Sundance Unit 6 will maintain the same generator nameplate capacity of 395 MW and 401 MW, respectively. These conversion to gas projects will reduce our $CO_2$ emissions by more than half and advances our plan to be 100 per cent clean electricity in Alberta by the end of 2021.

## D. Sale of the Pioneer Pipeline

On June 30, 2021, the Corporation closed the previously announced sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest, are approximately $128 million, subject to certain adjustments. Following closing of the transaction, the Pioneer Pipeline will be integrated into NOVA Gas Transmission Ltd. ("NGTL") and ATCO's Alberta natural gas transmission systems to provide reliable natural gas supply to the Corporation's power generation stations at Sundance and Keephills. As part of the transaction, TransAlta has entered into additional long-term gas transportation agreements with NGTL for new and existing transportation service of 400 TJ per day by the end of 2023. Please refer to Note 18 for further details.

As a result of this sale, the Corporation has derecognized the related Pioneer Pipeline assets which were classified as assets held for sale ($97 million) and recognized a gain on sale of $31 million on the statement 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 the derecognition of the right of use asset ($41 million) and lease liability ($43 million) related to the pipeline, resulting in a gain of $2 million.

## E. Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. The agreement provides that if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the agreement will automatically terminate on Dec. 31, 2025. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. The Corporation is in active discussions with the three other existing industrial off-takers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. On July 19, 2021, the IESO released an Annual Acquisition Report which included draft details for mid and long-term procurement mechanisms for capacity for 2026 and beyond for existing and new generation. The Corporation will participate in the consultation process, seeking to secure a contract extension for the Sarnia Cogeneration facility following the end of the current contract.

### F. Garden Plain Wind Project

On May 3, 2021, the Corporation announced that it entered into a long-term PPA with Pembina Pipeline Corporation ("Pembina") pursuant to which Pembina has contracted for the renewable electricity and environmental credits of 100 MWs of the 130 MW Garden Plain wind project ("Garden Plain"). Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the power purchase agreement). The option must be exercised no later than 30 days after commercial operational date. TransAlta would remain the operator of the facility and earn a service fee if Pembina exercises this option. Garden Plain will be located approximately 30 km north of Hanna, Alberta. Construction activities are scheduled to start in fall 2021 with completion of the project expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

### G. Mangrove Claim

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming TransAlta Corporation, the incumbent members of the Board of Directors of TransAlta Corporation on such date, and Brookfield BRP Holdings (Canada) as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

### H. Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the Alberta power purchase arrangement. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021 and this matter is now resolved.

### I. TransAlta Renewables Acquisitions

The Corporation completed the sale of its 100 per cent direct interest in the 207 MW Windrise wind project ("Windrise") to TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Corporation, on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise will be paid by TransAlta Renewables. Windrise is expected to commence commercial operation in the second half of 2021.

On April 1, 2021, the Corporation also completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility ("Ada") and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility ("Skookumchuck") to TransAlta Renewables for $43 million and $103 million, respectively. Both facilities are fully operational. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities. The Ada cogeneration facility is under a PPA until 2026. The Skookumchuck wind facility is contracted under a PPA until 2040 with an investment grade counterparty.

### J. Global Pandemic

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic.

Notwithstanding the challenges associated with the pandemic, all of the Corporation's facilities continue to remain fully operational and capable of meeting our customers' needs. The Corporation continues to work and serve all customers and counterparties under the terms of their contracts. The Corporation has not experienced interruptions to service requirements. Electricity and steam supply continue to remain a critical service requirement to all customers and have been deemed an essential service in the Corporation's jurisdictions.

The Corporation continues to maintain a strong financial position due in part to the long-term contracts and hedged positions. At the end of the second quarter, we had access to $2.0 billion in liquidity including $642 million in cash and cash equivalents.

# 4. Revenue

## A. Disaggregation of Revenue

The majority of the Corporation'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 Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

| 3 months ended June 30, 2021 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal | Centralia | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Revenue from contracts with customers** | | | | | | | | | |
| Power and other | **13** | **49** | **44** | **28** | **8** | **1** | **—** | **—** | **143** |
| Environmental credits[1] | **—** | **4** | **—** | **—** | **—** | **—** | **—** | **—** | **4** |
| **Revenue from contracts with customers** | **13** | **53** | **44** | **28** | **8** | **1** | **—** | **—** | **147** |
| Revenue from leases[2] | **—** | **—** | **5** | **—** | **—** | **—** | **—** | **—** | **5** |
| Revenue from derivatives and other trading activities[3] | **—** | **3** | **3** | **—** | **(55)** | **48** | **38** | **4** | **41** |
| Merchant revenue and other | **101** | **19** | **1** | **2** | **295** | **8** | **—** | **—** | **426** |
| **Total revenue** | **114** | **75** | **53** | **30** | **248** | **57** | **38** | **4** | **619** |
| **Revenue from contracts with customers** | | | | | | | | | |
| Timing of revenue recognition | | | | | | | | | |
| At a point in time | **—** | **4** | **—** | **—** | **4** | **1** | **—** | **—** | **9** |
| Over time | **13** | **49** | **44** | **28** | **4** | **—** | **—** | **—** | **138** |
| **Total revenue from contracts with customers** | **13** | **53** | **44** | **28** | **8** | **1** | **—** | **—** | **147** |

*(1) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.*
*(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.*
*(3) Represents realized and unrealized gains or losses from hedging positions.*

| 3 months ended June 30, 2020 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal[1] | Centralia[1] | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| Revenue from contracts with customers | | | | | | | | | |
| Power and other[2] | 39 | 55 | 43 | 22 | 78 | 1 | — | — | 238 |
| Environmental credits[3] | — | 7 | — | — | — | — | — | — | 7 |
| Total revenue from contracts with customers | 39 | 62 | 43 | 22 | 78 | 1 | — | — | 245 |
| Revenue from leases[4] | — | — | 1 | 16 | 14 | — | — | — | 31 |
| Revenue from derivatives and other trading activities[5] | — | (6) | — | — | 20 | 67 | 25 | 1 | 107 |
| Merchant revenue and other | 3 | 18 | 4 | 1 | 28 | — | — | — | 54 |
| Total revenue | 42 | 74 | 48 | 39 | 140 | 68 | 25 | 1 | 437 |
| Revenue from contracts with customers | | | | | | | | | |
| Timing of revenue recognition | | | | | | | | | |
| At a point in time | — | 7 | — | — | 6 | 1 | — | — | 14 |
| Over time | 39 | 55 | 43 | 22 | 72 | — | — | — | 231 |
| Total revenue from contracts with customers | 39 | 62 | 43 | 22 | 78 | 1 | — | — | 245 |

*(1) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.*
*(2) Certain contract balances within the Wind and Solar segment and North American Gas Segments have been reclassified from revenue from contracts with customers to merchant revenue and other or revenue from leases.*
*(3) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.*
*(4) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.*
*(5) Represents realized and unrealized gains or losses from hedging positions.*

| 6 months ended June 30, 2021 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal | Centralia | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Revenue from contracts with customers** | | | | | | | | | |
| Power and other | **13** | **112** | **108** | **57** | **14** | **3** | **—** | **—** | **307** |
| Environmental credits[1] | **—** | **9** | **—** | **—** | **—** | **—** | **—** | **—** | **9** |
| **Revenue from contracts with customers** | **13** | **121** | **108** | **57** | **14** | **3** | **—** | **—** | **316** |
| Revenue from leases[2] | **—** | **—** | **10** | **—** | **—** | **—** | **—** | **—** | **10** |
| Revenue from derivatives and other trading activities[3] | **—** | **(1)** | **4** | **—** | **(96)** | **98** | **99** | **5** | **109** |
| Merchant revenue and other | **190** | **41** | **5** | **4** | **536** | **50** | **—** | **—** | **826** |
| **Total revenue** | **203** | **161** | **127** | **61** | **454** | **151** | **99** | **5** | **1,261** |
| **Revenue from contracts with customers** | | | | | | | | | |
| Timing of revenue recognition | | | | | | | | | |
| At a point in time | **—** | **9** | **—** | **—** | **8** | **3** | **—** | **—** | **20** |
| Over time | **13** | **112** | **108** | **57** | **6** | **—** | **—** | **—** | **296** |
| **Total revenue from contracts with customers** | **13** | **121** | **108** | **57** | **14** | **3** | **—** | **—** | **316** |

*(1) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.*
*(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.*
*(3) Represents realized and unrealized gains or losses from hedging positions.*

| 6 months ended June 30, 2020 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal[1] | Centralia[1] | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| Revenue from contracts with customers | | | | | | | | | |
| Power and other[2] | 75 | 116 | 87 | 43 | 155 | 5 | — | — | 481 |
| Environmental credits[3] | — | 15 | — | — | — | — | — | (5) | 10 |
| Total revenue from contracts with customers | 75 | 131 | 87 | 43 | 155 | 5 | — | (5) | 491 |
| Revenue from leases[4] | — | — | 5 | 31 | 27 | — | — | — | 63 |
| Revenue from derivatives and other trading activities[5] | — | 5 | 1 | — | 22 | 166 | 53 | 3 | 250 |
| Merchant revenue and other | 5 | 43 | 6 | 4 | 142 | 39 | — | — | 239 |
| Total revenue | 80 | 179 | 99 | 78 | 346 | 210 | 53 | (2) | 1,043 |
| Revenue from contracts with customers | | | | | | | | | |
| Timing of revenue recognition | | | | | | | | | |
| At a point in time | — | 11 | — | — | 11 | 5 | — | — | 27 |
| Over time | 75 | 120 | 87 | 43 | 144 | — | — | (5) | 464 |
| Total revenue from contracts with customers | 75 | 131 | 87 | 43 | 155 | 5 | — | (5) | 491 |

*(1) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.*
*(2) Certain contract balances within the Wind and Solar segment and North American Gas Segments have been reclassified from revenue from contracts with customers to merchant revenue and other or revenue from leases.*
*(3) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.*
*(4) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.*
*(5) Represents realized and unrealized gains or losses from hedging positions.*

## 5. Expenses by Nature

Fuel and purchased power and operations, maintenance and administrative ("OM&A") expenses classified by nature are as follows:

| | **3 months ended June 30** | | | | **6 months ended June 30** | | | |
|---|---|---|---|---|---|---|---|---|
| | **2021** | | 2020 | | **2021** | | 2020 | |
| | **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[1] | **62** | **—** | 31 | — | **120** | **—** | 71 | — |
| Coal fuel costs[1][2] | **24** | **—** | 16 | — | **70** | | 85 | — |
| Royalty, land lease, other direct costs | **5** | **—** | 6 | — | **10** | **—** | 11 | — |
| Purchased power | **64** | **—** | 25 | — | **133** | **—** | 64 | — |
| Mine depreciation[3] | **50** | **—** | 25 | — | **105** | **—** | 53 | — |
| Salaries and benefits | **7** | **61** | 13 | 54 | **17** | **107** | 25 | 121 |
| Other operating expenses[4] | **—** | **90** | — | 58 | **—** | **149** | — | 119 |
| **Total** | **212** | **151** | 116 | 112 | **455** | **256** | 309 | 240 |

*(1) In the first and second quarters of 2021, fuel costs have been split to show gas and coal fuel costs separately within the above table and carbon compliance costs have been reclassified from fuel and purchased power to a separate line called carbon compliance costs on the condensed consolidated statements of earnings (loss). Prior periods have been adjusted to reflect these reclassifications.*
*(2) Included in coal fuel costs for the three and six months ended June 30, 2021, were $3 million and $11 million, respectively, related to the impairment of coal inventory recorded during 2021 .*
*(3) Included in mine depreciation for the three and six months ended June 30, 2021, were $12 million and $29 million, respectively, related to the impairment of mine depreciation recorded during2021.*
*(4) During the second quarter of 2021, OM&A costs included a writedown of $25 million for parts and material inventory related to the Highvale mine and coal operations at our gas converted facilities. Please refer to Note 12 for further details.*

# 6. Asset Impairment Charges and Reversals

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| PP&E impairment - Kaybob Cogeneration Project | **—** | — | **27** | — |
| Intangible asset impairment - Coal Rights(1) | **—** | — | **14** | — |
| Changes in decommissioning and restoration provisions for retired assets(2) | **6** | 32 | **(6)** | (9) |
| PP&E impairment - Alberta Thermal(3) | **10** | — | **10** | — |
| **Asset impairment (reversal)** | **16** | 32 | **45** | (9) |

*(1) Impaired to nil as no future coal will be extracted from this area of the mine.*
*(2) Change primarily due to changes in discount rates on retired assets.*
*(3) Certain capital spares and vehicles at the Highvale mine have been impaired as they will not be utilized in our converted gas facilities. Amounts have been adjusted to the expected recoverable amount less costs of disposal.*

## Kaybob Cogeneration Project

Energy Transfer Canada, formerly SemCAMS Midstream ULC ("ET Canada") 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 Corporation 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. TransAlta has commenced an arbitration seeking compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the Agreements were lawfully terminated. Please refer to Note 18 for further details.

# 7. Net Interest Expense

The components of net interest expense are as follows:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Interest on debt | **40** | 39 | **80** | 82 |
| Interest on exchangeable debentures | **7** | 8 | **14** | 15 |
| Interest on exchangeable preferred shares | **7** | — | **14** | — |
| Interest income | **(3)** | (2) | **(6)** | (5) |
| Capitalized interest | **(3)** | (1) | **(8)** | (2) |
| Interest on lease liabilities | **2** | 2 | **4** | 4 |
| Credit facility fees, bank charges and other interest | **4** | 5 | **8** | 9 |
| Tax shield on tax equity financing | **—** | — | **1** | — |
| Other | **(1)** | — | **2** | 1 |
| Accretion of provisions | **7** | 6 | **14** | 15 |
| **Net interest expense** | **60** | 57 | **123** | 119 |

## 8. Income Taxes

The components of income tax expense are as follows:

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Current income tax expense | **12** | 12 | **35** | 21 |
| Deferred income tax recovery related to the origination and reversal of temporary differences | **—** | (14) | **(19)** | (24) |
| Deferred income tax expense arising from the writedown (reversal of previous writedowns) of deferred income tax assets[1] | **32** | (15) | **48** | (12) |
| **Income tax expense (recovery)** | **44** | (17) | **64** | (15) |

| | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Current income tax expense | **12** | 12 | **35** | 21 |
| Deferred income tax expense (recovery) | **32** | (29) | **29** | (36) |
| **Income tax expense (recovery)** | **44** | (17) | **64** | (15) |

*(1) During the three and six months ended June 30, 2021, the Corporation recorded a writedown on deferred tax assets of $32 million and $48 million, respectively (June 30, 2020 - reversed a previous writedown of $15 million and $12 million). The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. The Corporation wrote these assets off as it is not considered probable that sufficient future taxable income will be available from the Corporation's directly owned US operations to utilize the underlying tax losses.*

## 9. Non-Controlling Interests

The Corporation'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 June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| **Net earnings** | | | | |
| TransAlta Cogeneration L.P. | **19** | 2 | **31** | 5 |
| TransAlta Renewables | **11** | 13 | **30** | 17 |
| | **30** | 15 | **61** | 22 |
| **Total comprehensive income (loss)** | | | | |
| TransAlta Cogeneration L.P. | **19** | 2 | **31** | 5 |
| TransAlta Renewables | **14** | (15) | **(8)** | 7 |
| | **33** | (13) | **23** | 12 |
| **Cash distributions paid to non-controlling interests** | | | | |
| TransAlta Cogeneration L.P. | **5** | 3 | **17** | 4 |
| TransAlta Renewables | **25** | 20 | **50** | 38 |
| | **30** | 23 | **67** | 42 |

| **As at** | **June 30, 2021** | Dec. 31, 2020 |
|---|---|---|
| Equity attributable to non-controlling interests | | |
| TransAlta Cogeneration L.P. | **150** | 136 |
| TransAlta Renewables | **890** | 948 |
| | **1,040** | 1,084 |
| Non-controlling interests share (per cent) | | |
| TransAlta Cogeneration L.P. | **49.99** | 49.99 |
| TransAlta Renewables | **39.9** | 39.9 |

# 10. 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 Corporation 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 Corporation 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.

*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 Corporation 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 Corporation's valuation processes, valuation techniques, and types of inputs used in the fair value measurements during the period. For additional information, please refer to Note 15 of the 2020 audited annual consolidated financial statements.

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses or the offsetting impact of Level II positions. 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, commodity volatility and correlations, delivery volumes, escalation rates and cost of supply.

| **As at** | | | **June 30, 2021** | | | |
|---|---|---|---|---|---|---|
| **Description** | **Base fair value** | **Sensitivity** | **Valuation technique** | **Unobservable input** | **Range** | **Reasonable possible change** |
| Long-term power sale – US | **361** | +28<br>-124 | Long-term price forecast | Illiquid future power prices (per MWh) | US$27 to US$31 | Price decrease of US$3 or price increase of US$12 |
| Coal transportation - US | **(30)** | +9<br>-9 | Numerical derivation valuation | Illiquid future power prices (per MWh) | US$27 to US$31 | Price decrease of US$3 or price increase of US$12 |
| | | | | Volatility | 30% to 70% | 80% to 120% |
| | | | | Rail rate escalation | $22 to $24 | zero to 4% |
| Full requirements - Eastern US | **(49)** | +5<br>-4 | Historical bootstrap | Volume | | 95% to 105% |
| | | | | Cost of supply | | (+/-) US$1 per MWh |
| Long-term wind energy sale – Eastern US | **(20)** | +22<br>-22 | Long-term price forecast | Illiquid future power prices (per MWh) | US$34 to US$48 | Price increase or decrease of US$6 |
| | | | | Illiquid future REC prices (per unit) | US$2 to US$14 | Price decrease of US$3 or price increase of US$2 |
| Long-term wind energy sale – Canada | **(1)** | +31<br>-18 | Long-term price forecast | Illiquid future power prices (per MWh) | US$51 to US$98 | Price decrease of $26 or increase of $4 |
| | | | | Monthly wind discounts | 34% to 54% | 5% decrease or 5% increase |
| Others | **(16)** | +7<br>-13 | | | | |

| As at | | | Dec. 31, 2020 | | | |
|---|---|---|---|---|---|---|
| Description | Base fair value | Sensitivity | Valuation technique | Unobservable input | Range | Reasonable possible change |
| Long-term power sale – US | 598 | +35<br>-59 | Long-term price forecast | Illiquid future power prices (per MWh) | US$24 to US$32 | Price decrease of US$3 or a price increase of US$5 |
| Coal transportation - US | (16) | +3<br>-5 | Numerical derivative valuation | Illiquid future power prices (per MWh) | US$24 to US$32 | Price decrease of US$3 or a price increase of US$5 |
| | | | | Volatility | 15% to 40% | 80% to 120% |
| | | | | Rail rate escalation | US$21 to US$24 | zero to 4% |
| Full requirements - Eastern US | 11 | +3<br>-3 | Historical bootstrap | Volume | | 95% to 105% |
| | | | | Cost of supply | | (+/-) US$1 per MWh |
| Long-term wind energy sale – Eastern US | (29) | +22<br>-22 | Long-term price forecast | Illiquid future power prices (per MWh) | US$35 to US$52 | Price increase or decrease of US$6 |
| | | | | Illiquid future REC prices (per unit) | US$11 | Price increase or decrease of US$1 |
| Others | (4) | +5<br>-5 | | | | |

*i. Long-Term Power Sale – US*

The Corporation 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. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2020 to June 30, 2021, the base fair value and the sensitivity values have decreased by approximately $11 million and $4 million, respectively.

*ii. Coal Transportation - US*

The Corporation has a coal rail transport agreement that includes an upside sharing mechanism to the benefit of the supplier, with a contract start date of Jan. 1, 2021, and extending until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

*iii. Full Requirements – Eastern US*

The Corporation has a portfolio of full requirement service contracts, whereby the Corporation 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 Corporation has a long-term contract for differences whereby the Corporation 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. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

*v. Long-Term Wind Energy Sale – Canada*

In relation to the Garden Plain wind facility, the Corporation has entered into a virtual PPA whereby the Corporation receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. The contract commences on commercial operation of the facility, which is expected by the end of 2022, and extending for 18 years past that date. The energy component of the contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are the non-liquid forward prices for power and monthly wind discounts.

### 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 June 30, 2021, are as follows: Level I - $19 million net asset (Dec. 31, 2020 – $13 million net liability), Level II – $77 million net asset (Dec. 31, 2020 – $27 million net liability) and Level III – $245 million net asset (Dec. 31, 2020 – $582 million net asset).

Significant changes in commodity net risk management assets and liabilities during the six months ended June 30, 2021, are primarily attributable to volatility in market prices and 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 level during the six months ended June 30, 2021 and 2020, respectively:

| | **6 months ended June 30, 2021** | | | 6 months ended June 30, 2020 | | |
|---|---|---|---|---|---|---|
| | **Hedge** | **Non-hedge** | **Total** | Hedge | Non-hedge | Total |
| Opening balance | **573** | **9** | **582** | 678 | 8 | 686 |
| Changes attributable to: | | | | | | |
| Market price changes on existing contracts | **(142)** | **(46)** | **(188)** | 65 | 18 | 83 |
| Market price changes on new contracts | **—** | **(62)** | **(62)** | — | 4 | 4 |
| Contracts settled | **(70)** | **(1)** | **(71)** | (42) | (5) | (47) |
| Change in foreign exchange rates | **(17)** | **1** | **(16)** | 34 | (1) | 33 |
| **Net risk management assets (liabilities), end of period** | **344** | **(99)** | **245** | 735 | 24 | 759 |
| **Additional Level III information:** | | | | | | |
| Gains (losses) recognized in other comprehensive income | **(160)** | **—** | **(160)** | 99 | — | 99 |
| Total gains (losses) included in earnings before income taxes | **70** | **(107)** | **(37)** | 42 | 21 | 63 |
| Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end | **—** | **(108)** | **(108)** | — | 16 | 16 |

### 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 $10 million as at June 30, 2021 (Dec. 31, 2020 – $12 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the six months ended June 30, 2021, are primarily attributable to favourable changes in interest and foreign exchange rates.

### 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** |
|---|---|---|---|---|---|
| | **Level I** | **Level II** | **Level III** | **Total** | **value[1]** |
| **Exchangeable securities - June 30, 2021** | **—** | **779** | **—** | **779** | **732** |
| **Long-term debt - June 30, 2021** | **—** | **3,162** | **—** | **3,162** | **3,007** |
| | | | | | |
| Exchangeable securities - Dec. 31, 2020 | — | 769 | — | 769 | 730 |
| Long-term debt - Dec. 31, 2020 | — | 3,480 | — | 3,480 | 3,227 |

*(1) Includes current portion.*

The fair values of the Corporation'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 recorded in other assets approximate the carrying amounts as amounts receivable represent cash flows from repayments of principal and interest.

### C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. For derivatives that 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. Please refer to section B of this Note 10 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "Transaction Price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the Transaction Price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

| | 6 months ended June 30 | |
|---|---|---|
| | **2021** | 2020 |
| Unamortized net gain (loss) at beginning of period | **(33)** | 9 |
| New inception gains | **15** | 4 |
| Change in foreign exchange rates | **1** | (1) |
| Amortization recorded in net earnings during the period | **(7)** | (25) |
| **Unamortized net loss at end of period[1]** | **(24)** | (13) |

*(1) In the third quarter of 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day 1 forward price curve at inception of the contract.*

## 11. Risk Management Activities

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. The Corporation's risk management strategy, policies and controls are designed to ensure that the risk it assumes comply with the Corporation's internal objectives and its risk tolerance. For additional information on the Corporation's Risk Management Activities please refer to Note 16 of the 2020 audited annual consolidated financial statements.

### A. Net Risk Management Assets and Liabilities

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

**As at June 30, 2021**

| | Cash flow hedges | Not designated as a hedge | Total |
|---|---|---|---|
| **Commodity risk management** | | | |
| Current | **(3)** | **(12)** | **(15)** |
| Long-term | **345** | **11** | **356** |
| **Net commodity risk management assets** | **342** | **(1)** | **341** |
| **Other** | | | |
| Current | **4** | **(1)** | **3** |
| Long-term | **—** | **7** | **7** |
| **Net other risk management assets** | **4** | **6** | **10** |
| | | | |
| **Total net risk management assets** | **346** | **5** | **351** |

As at Dec. 31, 2020

| | Cash flow hedges | Not designated as a hedge | Total |
|---|---|---|---|
| Commodity risk management | | | |
| Current | 101 | (11) | 90 |
| Long-term | 471 | (19) | 452 |
| Net commodity risk management assets (liabilities) | 572 | (30) | 542 |
| Other | | | |
| Current | (9) | (4) | (13) |
| Long-term | — | 1 | 1 |
| Net other risk management liabilities | (9) | (3) | (12) |
| Total net risk management assets (liabilities) | 563 | (33) | 530 |

## B. Nature and Extent of Risks Arising from Financial Instruments

### I. Market Risk

*i. Commodity Price Risk Management – Proprietary Trading*

The Corporation'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 Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at June 30, 2021, associated with the Corporation's proprietary trading activities was $3 million (Dec. 31, 2020 - $1 million).

*ii. Commodity Price Risk – Generation*

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. VaR is used to determine the potential change in value of the Corporation's commodity derivative instruments used in association with generation activities, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with these activities affect net earnings in the period that the price changes occur. VaR at June 30, 2021, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $42 million (Dec. 31, 2020 - $12 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at June 30, 2021, associated with these transactions was $22 million (Dec. 31, 2020 - $15 million).

### II. Credit Risk

The Corporation 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 Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at June 30, 2021:

| | **Investment grade** *(Per cent)* | **Non-investment grade** *(Per cent)* | **Total** *(Per cent)* | **Total amount** |
|---|---|---|---|---|
| Trade and other receivables(1) | 91 | 9 | **100** | **695** |
| Long-term finance lease receivable | 100 | — | **100** | **201** |
| Risk management assets(1) | 94 | 6 | **100** | **681** |
| Loan receivable(2) | — | 100 | **100** | **54** |
| **Total** | | | | **1,631** |

*(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.*
*(2) The counterparty has no external credit rating.*

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at June 30, 2021, was $28 million (Dec. 31, 2020 - $22 million). TransAlta has implemented additional monitoring and risk mitigation measures to address the on-going impacts from the COVID-19 pandemic.

### III. Liquidity Risk

TransAlta continues to be in a strong financial position with no liquidity issues. The Corporation has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for November 2022. Our highly diversified asset portfolio, by both fuel type and operating region, provide stability in our cash flows and highlight the strength of our long-term contracted asset base.

Liquidity risk relates to the Corporation'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 Corporation'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:

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 and thereafter | Total |
|---|---|---|---|---|---|---|---|
| Accounts payable and accrued liabilities | 582 | — | — | — | — | — | 582 |
| Long-term debt[(1)] | 48 | 610 | 162 | 119 | 134 | 1,967 | 3,040 |
| Exchangeable securities[(2)] | — | — | — | — | 750 | — | 750 |
| Commodity risk management liabilities (assets) | 66 | (59) | (118) | (126) | (98) | (6) | (341) |
| Other risk management liabilities (assets) | 1 | (2) | (5) | (3) | — | (1) | (10) |
| Lease liabilities[(3)] | 2 | (6) | 4 | 3 | 2 | 79 | 84 |
| Interest on long-term debt and lease obligations[(4)] | 76 | 148 | 120 | 115 | 109 | 852 | 1,420 |
| Interest on exchangeable securities[(2,4)] | 26 | 52 | 53 | 53 | — | — | 184 |
| Dividends payable | 37 | — | — | — | — | — | 37 |
| **Total** | **838** | **743** | **216** | **161** | **897** | **2,891** | **5,746** |

*(1) Excludes impact of hedge accounting and derivatives.*
*(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Please refer to Note 15 for further details.*
*(3) Lease liabilities include a lease incentive of $13 million expected to be received in 2022.*
*(4) Not recognized as a financial liability on the condensed consolidated statements of financial position.*

## C. Collateral and Contingent Features in Derivative Instruments

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

As at June 30, 2021, the Corporation had posted collateral of $227 million (Dec. 31, 2020 – $163 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk contingent features, which if triggered could result in the Corporation having to post an additional $110 million (Dec. 31, 2020 – $85 million) of collateral to its counterparties.

# 12. Inventory

The cost of coal from the Highvale mine continues to increase as a result of the Corporation's decision to convert coal fired facilities to natural gas. The cost of coal is not expected to be recovered based on current power pricing. For the three and six months ended June 30, 2021, the fuel and purchased power includes a $15 million and $40 million writedown, respectively, on internally produced coal inventory to its net realizable value, of which $12 million and $29 million relates to increased depreciation from the accelerated closure of the mine.

The components of inventory are as follows:

| As at | June 30, 2021 | Dec. 31, 2020 |
|---|---|---|
| Parts and materials | **83** | 107 |
| Coal | **82** | 83 |
| Deferred stripping costs | **3** | 8 |
| Natural gas | **3** | 2 |
| Purchased emission credits | **37** | 38 |
| **Total** | **208** | 238 |

During the second quarter of 2021, OM&A costs included a writedown of $25 million for parts and material inventory related to the Highvale mine and coal operations at our gas converted facilities. With the accelerated shut down of the Highvale mine and progression towards full conversion to gas by the end of 2021, it was determined that a portion of the coal-related parts and materials inventory would not be utilized in the operations of our converted gas facilities and adjusted their values down to the expected net realizable amounts for the remainder of 2021.

Carbon compliance costs are regulated costs that the business incurs as a result of greenhouse gases emission generated from our operating units. TransAlta's exposure to carbon compliance costs is mitigated through the use of eligible emission credits generated from the Corporation's Wind and Solar and Hydro segments, as well as, purchasing emission credits from the market at prices lower than the regulated compliance price of carbon. Emission credits generated from our Alberta business have no recorded book value but are expected to be used to offset emission obligations from our Alberta Thermal and North American Gas segments in the future when the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. At June 30, 2021, we currently hold 1,531,198 credits of inventory purchased externally with a recorded book value of $37 million (Dec. 31, 2020 — 1,434,761 credits with a recorded book value of $38 million). The Corporation has approximately 736,213 (Dec. 31, 2020 — 502,653) of internally generated eligible emission credits with no recorded book value.

## 13. Property, Plant and Equipment

During the three and six months ended June 30, 2021, the Corporation had additions of $119 million and $217 million, respectively. The additions mainly related to assets under construction for the boiler conversions, Windrise wind project, Sundance Unit 5 repowering project and other planned major maintenance expenditures. Please refer to the Significant and Subsequent Events section for more details on the status of the Sundance Unit 5 repowering project.

## 14. Credit Facilities, Long-Term Debt and Lease Liabilities

The amounts outstanding are as follows:

| As at | June 30, 2021 | | | Dec. 31, 2020 | | |
|---|---|---|---|---|---|---|
| | **Carrying value** | **Face value** | **Interest[1]** | Carrying value | Face value | Interest[1] |
| Credit facilities[2] | **—** | **—** | **—%** | 114 | 114 | 2.7% |
| Debentures | **251** | **251** | **7.1%** | 249 | 251 | 7.1% |
| Senior notes[3] | **860** | **867** | **5.4%** | 886 | 894 | 5.4% |
| Non-recourse[4] | **1,765** | **1,784** | **4.1%** | 1,837 | 1,858 | 4.1% |
| Other[5] | **131** | **138** | **7.1%** | 141 | 147 | 7.1% |
| | **3,007** | **3,040** | | 3,227 | 3,264 | |
| Lease liabilities | **84** | | | 134 | | |
| | **3,091** | | | 3,361 | | |
| Less: current portion of long-term debt | **(109)** | | | (97) | | |
| Less: current portion of lease liabilities | **(6)** | | | (8) | | |
| Total current long-term debt and lease liabilities | **(115)** | | | (105) | | |
| **Total credit facilities, long-term debt and lease liabilities** | **2,976** | | | 3,256 | | |

*(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*
*(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.*
*(3) US face value at June 30, 2021 - US$700 million (Dec. 31, 2020 - US$700 million).*
*(4) Includes AU$800 million (Dec 31, 2020 - AU$800 million) senior secured note offering by TEC Hedland Pty Ltd., a subsidiary of the Corporation.*
*(5) Includes US$107 million at June 30, 2021 (Dec. 31, 2020 - US$110 million) of tax equity financing.*

The Corporation has $2.0 billion of committed syndicated credit facilities and $0.2 billion of committed bilateral credit facilities, of which $1.4 billion was available as at June 30, 2021 (Dec. 31, 2020 – $1.5 billion) including the undrawn letters of credit. This includes a $1.25 billion credit facility which was converted into a facility with a Sustainability-Linked Loan ("SLL") and which was extended to June 30, 2025. The facility's financing terms will align the cost of borrowing to TransAlta's greenhouse gas emission reduction and gender diversity targets, which are part of the Corporation's overall environment, social and governance, or ESG. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanic and could move either up, down or remain unchanged for each sustainability performance target based on performance. In addition, the Corporation's committed bilateral credit facilities were also extended to June 30, 2023.

As at June 30, 2021, the Corporation was in compliance with all debt covenants.

The weakening of the US dollar has decreased our US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $31 million as at June 30, 2021. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

| | **June 30, 2021** |
|---|---|
| Effects of foreign exchange on carrying amounts of US operations (net investment hedge) | **(14)** |
| Foreign currency economic cash flow hedges on debt | **(6)** |
| Economic hedges and other | **(7)** |
| Unhedged | **(4)** |
| **Total** | **(31)** |

Additionally, the weakening of the Australian dollar has decreased our Australian-denominated non-recourse senior secured notes by approximately $33 million. As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income and not in foreign exchange gains (losses) on the statement of earnings.

# 15. Exchangeable Securities

## A. $750 Million Exchangeable Securities

| As at | June 30, 2021 | | | Dec. 31, 2020 | | |
|---|---|---|---|---|---|---|
| | **Carrying value** | **Face value** | **Interest** | Carrying value | Face value | Interest |
| Exchangeable debentures – due May 1, 2039 | **332** | **350** | **7 %** | 330 | 350 | 7 % |
| Exchangeable preferred shares(1) | **400** | **400** | **7 %** | 400 | 400 | 7 % |
| Total Exchangeable Securities | **732** | **750** | | 730 | 750 | |

*(1) Exchangeable preferred share dividends are reported as interest expense.*

On May 3, 2021, the Corporation declared a dividend of $7 million in aggregate for the issued and outstanding Cumulative Redeemable Rate Reset First Preferred Share, Series I ("Exchangeable Preferred Shares") at the fixed rate of 1.726 per cent per Share paid on May 31, 2021. On Aug. 5, 2021, the Corporation declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.745 per cent, per Share payable on Aug. 31, 2021. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense (Note 7).

## B. Option to Exchange

| As at | June 30, 2021 | | Dec. 31, 2020 | |
|---|---|---|---|---|
| **Description** | **Base fair value** | **Sensitivity** | Base fair value | Sensitivity |
| Option to exchange – embedded derivative | — | nil<br>-41 | — | nil<br>-33 |

The Corporation entered into an investment agreement pursuant to which Brookfield Renewable Partners and its affiliates (collectively "Brookfield") invested $750 million in the Corporation through the purchase of exchangeable securities.

The investment agreement allows Brookfield the Option to Exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the Option to Exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the Option to Exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

# 16. Common Shares

## A. Issued and Outstanding

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

| | **6 months ended June 30** | | | |
|---|---|---|---|---|
| | **2021** | | 2020 | |
| | **Common shares *(millions)*** | **Amount** | Common shares *(millions)* | Amount |
| Issued and outstanding, beginning of period | **269.8** | **2,896** | 277.0 | 2,978 |
| Effect of share-based payment plans | **—** | **(3)** | — | (4) |
| Purchased and cancelled under the NCIB | **—** | **—** | (2.8) | (30) |
| Stock options exercised | **1.2** | **8** | — | — |
| Issued and outstanding, end of period | **271.0** | **2,901** | 274.2 | 2,944 |

### B. NCIB Program

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of our 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 18, 2021. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commences on May 31, 2021 and ends on May 30, 2022.

Shares purchased by the Corporation 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.

| | **June 30, 2021** | June 30, 2020 |
|---|---|---|
| Total shares purchased | — | 2,849,400 |
| Average purchase price per share | $ — | $ 7.51 |
| **Total cost** | — | 21 |
| Weighted average book value of shares cancelled | — | 30 |
| Amount recorded in deficit | — | 9 |

### C. Dividends

On May 3, 2021, the Corporation declared a quarterly dividend of $0.045 per common share, paid on July 1, 2021. On August 5, 2021, the Corporation declared a quarterly dividend of $0.045 per common share, payable on Oct. 1, 2021.

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.

### D. Stock Options

On May 4, 2021, the Corporation approved amendments to the Stock Option Plan to reduce the total aggregate number of common shares held in reserve for issuance under this program. The amendments reduce the aggregate total number of shares reserved for issuance to 14,500,000 common shares as at March 31, 2021 (Dec. 31, 2020 - 16,500,000 common shares).

## 17. Preferred Shares

### A. Issued and Outstanding

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

| | **June 30, 2021** | | Dec. 31, 2020 | |
|---|---|---|---|---|
| **Series** | **Number of shares** *(millions)* | **Amount** | Number of shares (millions) | Amount |
| Series A | **9.6** | **235** | 10.2 | 248 |
| Series B | **2.4** | **58** | 1.8 | 45 |
| Series C | **11.0** | **269** | 11.0 | 269 |
| 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 |

On March 18, 2021, the Corporation announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices. As a result of the conversion, the Corporation had 9.6 million Series A shares and 2.4 million Series B Shares issued and outstanding as at March 31, 2021.

## B. Dividends

The following table summarizes the value of preferred share dividends declared during the six months ended June 30, 2021 and 2020:

| Series | Quarterly amounts per share | 3 months ended June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|---|
| | | **2021** | 2020 | **2021**(1) | 2020 |
| A | 0.17981 | **2** | 1 | **2** | 3 |
| B(2) | 0.13108 | **—** | 1 | **—** | 1 |
| C | 0.25169 | **3** | 3 | **3** | 6 |
| E | 0.32463 | **3** | 3 | **3** | 6 |
| G | 0.31175 | **2** | 2 | **2** | 4 |
| **Total for the period** | | **10** | 10 | **10** | 20 |

*(1) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.*
*(2) 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.*

On May 3, 2021, the Corporation declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.13108 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, paid on June 30, 2021.

On August 5, 2021, the Corporation declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.13479 per share on the Series B preferred shares, $0.25169 per share on the Series C 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, 2021.

# 18. Commitments and Contingencies

## A. Commitments

In addition to the commitments disclosed elsewhere in these unaudited interim condensed consolidated financial statements and those disclosed in the 2020 audited annual financial statements, during 2021, the Corporation has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are shown in the table below. In addition, certain commitments disclosed in the 2020 audited annual financial statements are based on variable pricing. Any material updates to contracts containing variable pricing are discussed below.

### Natural Gas and Transportation Contracts

As part of the sale of the Pioneer Pipeline, the Corporation entered into a 15-year agreement for an additional 275 TJ per day of natural gas transportation on a firm basis by 2023, representing a new commitment of $439 million over the next 15 years. This agreement replaces, in part, the Corporation's existing 15-year commitment for natural gas transportation for 139 TJ per day on the Pioneer Pipeline, which was terminated on June 30, 2021, and was accounted for as a lease. As a result, the Corporation now has firm gas transportation contracts in place for 400 TJ per day by 2023. Additionally, on June 30, 2021 the Corporation's agreement to purchase 139 TJ per day of natural gas from Tidewater was terminated, which reduces the commitments disclosed at Dec. 31, 2020 by $1.7 billion.

## 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 Corporation'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 Corporation responds as required. For the current significant outstanding contingencies, please refer to Note 36 of the 2020 audited annual consolidated financial statements. The changes to these contingencies during the six months ended June 30, 2021 are included below:

### I. 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. The Corporation commenced an investigation to determine the root cause of each of the three events, which should be completed in the third quarter of 2021. The results of the investigation will help to determine if any liquidated damages are owing and, if so, the quantum.

**II. Transmission Line Loss Rule Proceeding**

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and the third and final invoice for $11 million was received in the first quarter of 2021. All invoices have settled as of the second quarter of 2021, which remain subject to true-up invoices expected to be issued by the AESO in Oct. 2021. The impact of the true-up invoices, if any, to the Corporation is not known at this time.

**III. Kaybob 3 Cogeneration Dispute**

The Corporation is engaged in a dispute with ET Canada as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing has not yet been scheduled but will likely occur sometime in 2022.

**IV. Fortescue Metals Group Ltd. Dispute**

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was to start on May 3, 2021 but, on May 2, 2021, the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions.

# 19. Segment Disclosures

## A. Reported Segment Earnings (Loss)

| 3 months ended June 30, 2021 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal | Centralia | Energy Marketing | Corporate | Total | Equity accounted investments(1) | IFRS Financials |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenues | 114 | 79 | 53 | 30 | 248 | 57 | 38 | 4 | 623 | (4) | 619 |
| Fuel and purchased power(2) | 3 | 3 | 18 | 3 | 128 | 53 | — | 4 | 212 | — | 212 |
| Carbon compliance(2) | — | — | 5 | — | 37 | — | — | — | 42 | — | 42 |
| Gross margin | 111 | 76 | 30 | 27 | 83 | 4 | 38 | — | 369 | (4) | 365 |
| Operations, maintenance, and administration | 14 | 15 | 13 | 8 | 58 | 12 | 7 | 24 | 151 | — | 151 |
| Depreciation and amortization | 9 | 36 | 11 | 7 | 42 | 13 | 1 | 6 | 125 | (2) | 123 |
| Asset impairment | — | — | — | — | 12 | 4 | — | — | 16 | — | 16 |
| Taxes, other than income taxes | 1 | 2 | 1 | — | 4 | 1 | — | — | 9 | (1) | 8 |
| Net other operating income | — | — | — | — | (11) | — | — | — | (11) | — | (11) |
| Operating income (loss) | 87 | 23 | 5 | 12 | (22) | (26) | 30 | (30) | 79 | (1) | 78 |
| Equity income from associate | — | — | — | — | — | — | — | (2) | (2) | 4 | 2 |
| Finance lease income | — | — | 1 | 5 | — | — | — | — | 6 | — | 6 |
| Net interest expense | | | | | | | | | (58) | (2) | (60) |
| Foreign exchange gain | | | | | | | | | 14 | — | 14 |
| Gain on sale of assets | | | | | | | | | 32 | — | 32 |
| **Earnings before income taxes** | | | | | | | | | **71** | **1** | **72** |

*(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.*
*(2) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.*

| 3 months ended June 30, 2020 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal(1) | Centralia(1) | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| Revenues | 42 | 74 | 48 | 39 | 140 | 68 | 25 | 1 | 437 |
| Fuel and purchased power(2) | 2 | 4 | 14 | 2 | 76 | 17 | — | 1 | 116 |
| Carbon compliance(2) | — | — | — | — | 35 | — | — | — | 35 |
| Gross margin | 40 | 70 | 34 | 37 | 29 | 51 | 25 | — | 286 |
| Operations, maintenance, and administration | 10 | 13 | 12 | 9 | 33 | 15 | 6 | 14 | 112 |
| Depreciation and amortization | 7 | 34 | 10 | 12 | 68 | 25 | 1 | 6 | 163 |
| Asset impairment | — | — | — | — | 2 | 30 | — | — | 32 |
| Taxes, other than income taxes | 1 | 2 | — | — | 3 | 2 | — | — | 8 |
| Net other operating income | — | — | — | — | (10) | — | — | — | (10) |
| Operating income (loss) | 22 | 21 | 12 | 16 | (67) | (21) | 18 | (20) | (19) |
| Finance lease income | — | — | 1 | — | — | — | — | — | 1 |
| Net interest expense | | | | | | | | | (57) |
| Foreign exchange gain | | | | | | | | | 23 |
| Loss before income taxes | | | | | | | | | (52) |

*(1) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.*
*(2) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted.*

| 6 months ended June 30, 2021 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal | Centralia | Energy Marketing | Corporate | Total | Equity accounted investments[1] | IFRS Financials |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenues | 203 | 170 | 127 | 61 | 454 | 151 | 99 | 5 | 1,270 | (9) | 1,261 |
| Fuel and purchased power[2] | 4 | 7 | 42 | 5 | 265 | 127 | — | 5 | 455 | — | 455 |
| Carbon compliance[2] | — | — | 12 | — | 80 | — | — | — | 92 | — | 92 |
| Gross margin | 199 | 163 | 73 | 56 | 109 | 24 | 99 | — | 723 | (9) | 714 |
| Operations, maintenance, and administration | 24 | 28 | 25 | 18 | 88 | 25 | 17 | 32 | 257 | (1) | 256 |
| Depreciation and amortization | 13 | 71 | 23 | 14 | 114 | 28 | 1 | 12 | 276 | (4) | 272 |
| Asset impairment | — | — | — | — | 18 | — | — | 27 | 45 | — | 45 |
| Taxes, other than income taxes | 2 | 5 | 1 | — | 8 | 2 | — | — | 18 | (1) | 17 |
| Net other operating income | — | — | — | — | (21) | — | — | — | (21) | — | (21) |
| Operating income (loss) | 160 | 59 | 24 | 24 | (98) | (31) | 81 | (71) | 148 | (3) | 145 |
| Equity income from associate | — | — | — | — | — | — | — | (2) | (2) | 6 | 4 |
| Finance lease income | — | — | 2 | 11 | — | — | — | — | 13 | — | 13 |
| Net interest expense | | | | | | | | | (121) | (2) | (123) |
| Foreign exchange gain | | | | | | | | | 21 | — | 21 |
| Gain on sale of assets | | | | | | | | | 33 | — | 33 |
| **Earnings before income taxes** | | | | | | | | | 92 | 1 | 93 |

*(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.*
*(2) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.*

| 6 months ended June 30, 2020 | Hydro | Wind and Solar | North American Gas | Australian Gas | Alberta Thermal[1] | Centralia[1] | Energy Marketing | Corporate | Total |
|---|---|---|---|---|---|---|---|---|---|
| Revenues | 80 | 179 | 99 | 78 | 346 | 210 | 53 | (2) | 1,043 |
| Fuel and purchased power[2] | 4 | 9 | 27 | 5 | 181 | 85 | — | (2) | 309 |
| Carbon compliance[2] | — | — | 1 | — | 79 | — | — | — | 80 |
| Gross margin | 76 | 170 | 71 | 73 | 86 | 125 | 53 | — | 654 |
| Operations, maintenance, and administration | 19 | 26 | 24 | 16 | 66 | 31 | 15 | 43 | 240 |
| Depreciation and amortization | 13 | 67 | 21 | 23 | 135 | 47 | 1 | 12 | 319 |
| Asset impairment reversal | — | — | — | — | (2) | (7) | — | — | (9) |
| Taxes, other than income taxes | 2 | 4 | 1 | — | 7 | 3 | — | — | 17 |
| Net other operating income | — | — | — | — | (20) | — | — | — | (20) |
| Operating income (loss) | 42 | 73 | 25 | 34 | (100) | 51 | 37 | (55) | 107 |
| Finance lease income | — | — | 2 | — | — | — | — | — | 2 |
| Net interest expense | | | | | | | | | (119) |
| Foreign exchange gain | | | | | | | | | 4 |
| Loss before income taxes | | | | | | | | | (6) |

*(1) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.*
*(2) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted.*

### B. 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 June 30 | | 6 months ended June 30 | |
|---|---|---|---|---|
| | **2021** | 2020 | **2021** | 2020 |
| Depreciation and amortization expense on the condensed consolidated statements of earnings (loss) | **123** | 163 | **272** | 319 |
| Depreciation included in fuel and purchased power (Note 5) | **50** | 25 | **105** | 53 |
| **Depreciation and amortization on the condensed consolidated statements of cash flows** | **173** | 188 | **377** | 372 |

# Exhibit 1

*(Unaudited)*

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the audited annual consolidated financial statements.

## To the Financial Statements of TransAlta Corporation

## EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the twelve months ended June 30, 2021:

### Earnings coverage on long-term debt supporting the Corporation’s Shelf Prospectus

(0.2) times

*Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.*

# Glossary of Key Terms

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

### Alberta Electricity Portfolio
The Alberta portfolio includes hydro, wind, energy storage and thermal units operating, primarily, on a merchant basis in the Alberta market.

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

### Alberta Power Purchase Arrangement (Alberta PPA)
A long-term arrangement that had been established by Alberta regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

### 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, the Highvale Mine and includes our non operated Sheerness facility.

### AUC
Alberta Utilities Commission.

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

### 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. Their current obligations and responsibilities are governed by the Alberta *Electric Utilities Act* (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

### Boiler
A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

### Carbon Tax
The carbon price per tonne of greenhouse gas emissions related to transportation fuels, heating fuels and other small emission sources.

### 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.

### Combined cycle
An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

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

### Disclosure Controls and Procedures (DC&P)
Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Corporation 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 Corporation 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.

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

### Force Majeure
Literally means “greater force.” These clauses generally 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 Corporation through its operations (cash from operations) minus the funds used by the Corporation for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Corporation (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 Corporation believes are not representative of ongoing cash flows from operations.

### FVOCI
Fair value through other comprehensive income; where fair value accounting adjustments are recorded through the statement other comprehensive income.

### 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.

### 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 Corporation'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)
An agreement for the sale of electric energy.

### 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.

**TransAlta Corporation**
110 - 12th Avenue S.W.
Box 1900, Station “M”
Calgary, Alberta T2P 2M1

**Phone**
403.267.7110

**Website**
www.transalta.com

**Computershare Trust Company of Canada**
Suite 800, 324 - 8th Avenue SW
Calgary, Alberta T2P 2Z2

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

**Fax**
Toll-free in North America: 1.800.453.0330
Outside North America: 403.267.6529

**Website**
www.investorcentre.com

## FOR MORE INFORMATION

### Investor Inquiries

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

**E-mail**
investor_relations@transalta.com

### Media Inquiries

**Phone**
Toll-free 1.855.255.9184
or 403.267.2540

**E-mail**
TA_Media_Relations@transalta.com