TransAlta™

TRANSALTA CORPORATION
Third Quarter Report for 2019

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 nine months ended Sept. 30, 2019 and 2018, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2018 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 Sept. 30, 2019. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Nov. 6, 2019. 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.

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 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 financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income in our Condensed Consolidated Statements of Earnings (Loss) for the three and nine months ended Sept. 30, 2019 and 2018. 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. Certain of the financial measures discussed in this MD&A are not defined 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 earnings before interest, tax, depreciation and amortization ("EBITDA"), deconsolidated comparable EBITDA, funds from operations ("FFO"), deconsolidated FFO, free cash flow ("FCF"), 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. See the Discussion of Consolidated Financial Results, Segmented Comparable Results, Key Financial Ratios and Capital Structure and Liquidity sections of this MD&A for additional information.

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 strategic focus, including as it pertains to our operating performance and transitioning to clean power generation; expectations regarding the Pioneer Pipeline, including the increase of co-firing at merchant units; achieving our targeted key financial ratios; redeploying the recently acquired two 230 MW Siemens F class gas turbines to our Sundance site in order to repower Sundance Unit 5; the clean energy investment plan, including plans relating to the conversion of some or all of the units at Sundance and Keephills and the timing thereof and the repowering of two units to highly efficient combined cycle natural gas units; the benefits of the clean energy investment plan, including being a low-cost generator, extending the life of the assets and reducing air emissions and costs; the operation of Sundance Unit 5 and Keephills Unit 1 ahead of repowering, including either by co-firing or through a boiler conversion; the source of funding for the clean energy investment plan; returning up to $250 million to common shareholders; reducing corporate debt by $400 million in 2020; the timing for the conversions, including the issuance of the notices to proceed for the Keephills Units 2 and 3 boiler conversions and the Sundance

Unit 5 and, if applicable, Keephills Unit 1 repowering; the costs incurred in 2019 to maximize the ability to co-fire; the cost and timing of completion of projects under development and construction, including the Big Level wind project, Antrim wind project, Windrise wind project, Windcharger energy storage project and Skooumchuk wind energy project; the $750 million investment by Brookfield, including the closing of the second tranche of $400 million of preferred shares, the use of proceeds, and the expected benefits associated with the Brookfield investment; pit development work and planned power maintenance outages; the Windcharger project, including that it will be the first utility-scale battery storage project in Alberta, it will receive funds from Emissions Reduction Alberta, the supply of lithium-ion batteries, the receipt of regulatory approvals; the expected benefits from Project Greenlight and embedding the program into the business and realization of new value; that TransAlta and Brookfield will work together to complete TransAlta's transition to clean energy, maximize the value of TransAlta's Alberta Hydro Assets consisting of 13 facilities currently subject to the power purchase arrangement ("PPA") with the Balancing Pool (the "Alberta Hydro Assets"), and create long-term shareholder value; Brookfield's increase in its share ownership to 9%; the construction and operation of the Kaybob cogeneration project, including the capital cost, expected annual EBITDA, SemCAMS' investment of a 50% interest and the associated reduction in emissions;; the tax equity financing relating to Big Level and Antrim, including the amount and closing thereof; the estimated decommissioning and restoration expenses; Canadian Federal regulatory developments, including carbon pricing, the "backstop" mechanism and clean fuel standard; Alberta regulatory changes, including the Technology Innovation and Emission Reduction regime and maintaining an energy-only market; Ontario regulatory changes, including as it pertains to the large greenhouse gas emitter regulation, carbon tax, and the electricity market review; the terms of the new lease commitment; the exposure under the Alberta Utilities Commission line loss proceeding, including the reduction to $10 million following the transaction with Capital Power; the claims with Fortescue Metals Group in Australia; the various power purchase arrangement disputes with the Balancing Pool; the section under "2019 Financial Outlook", including the Comparable EBITDA, the revised FCF guidance of $300 million to $340 million, dividend levels, availability for our generating segments, market pricing and hedging strategy, portfolio management strategy, fuel costs, energy marketing, net interest expense, liquidity and capital resources, growth expenditures and lost production as a result of major maintenance, remaining estimated capital spend on growth projects in 2019, and estimated total sustaining and productivity capital in 2019; source of capital for funding capital expenditures; and impact of accounting changes.

The forward looking statements in this MD&A are based on TransAlta's beliefs and assumptions based on information available at the time the assumptions were made, including assumptions pertaining to: the Corporation's ability to successfully defend against or pursue any existing or potential legal actions or regulatory proceedings; the closing of the second tranche of the Brookfield investment occurring and other risks to the Brookfield investment not materializing; no significant changes to regulatory, securities, credit or market environments; our ownership of or relationship with TransAlta Renewables Inc. ("TransAlta Renewables") not materially changing; the Alberta Hydro Assets achieving their anticipated future value, cash flows and adjusted EBITDA; the anticipated benefits and financial results generated on the coal-to-gas conversions and the Corporation's other strategies; the Corporation's strategies and plans; no significant changes in applicable laws, including any tax or regulatory changes in the markets in which we operate; the anticipated structure and framework of an Alberta capacity market in the future; risks associated with the impact of the Brookfield investment on the Corporation's stakeholders, including its shareholders, debtholders and other securityholders and credit ratings; assumptions referenced in our 2019 guidance, including: Alberta spot power price equal to $50 to $60 per megawatt hours ("MWh"); Alberta contracted power price equal to $50 to $55 per MWh; Mid-C spot power prices equal to US$20 to US$25 per MWh; Mid-C contracted power price of US$47 to US$53 per MWh; sustaining capital between $140 million and $165 million; no material decline in the dividends expected to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion; and assumptions relating to the completion of the strategic partnership with and investment by Brookfield and proposed share buy-backs. The forward-looking statements contained in this MD&A are subject to a number of risks and uncertainties that may cause actual performance, events or results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause such differences include: the failure of the second tranche of the Brookfield investment to close; the outcomes of existing or potential legal actions or regulatory proceedings not being as anticipated, including those pertaining to the Brookfield investment; changes in our relationships with Brookfield and its affiliated entities or our other shareholders; our Alberta Hydro Assets not achieving their anticipated value, cash flows or adjusted EBITDA; the Brookfield investment not resulting in the expected benefits for the Corporation and its shareholders; the inability to complete share buy-backs within the timeline or on the terms anticipated, or at all; fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; changes in the current or anticipated legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; risks associated with the calculation of the Alberta Hydro Assets' EBITDA, including non-financial measures included in that calculation; the anticipated benefits of the joint Brookfield/TransAlta hydro operating committee not materializing; the timing and value of Brookfield's exchange of exchangeable securities and the amount of equity interest in the Alberta Hydro Assets resulting therefrom; changes in general economic conditions including interests rates; operational risks involving our facilities; unexpected increases in cost structure; failure to meet financial expectations; structural subordination of securities; and other risks and uncertainties contained in the Corporation's Management Proxy Circular dated March 26, 2019 and its Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2018, filed under the Company's profile with the Canadian securities regulators on www.sedar.com and the U.S. 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 Corporation is providing the guidance and other forward looking information for the purpose of assisting shareholders and financial analysts in understanding our financial position and results of operations as at and for the periods ended on the dates presented, as well as our financial performance objectives, vision and strategic goals, and may not be appropriate for other purposes. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. 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.

Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Revenues	**593**	593	**1,738**	1,627
Operations, maintenance, and administration	**114**	120	**348**	376
Net earnings (loss) attributable to common shareholders	**51**	(86)	**(14)**	(126)
Cash flow from operating activities	**328**	159	**668**	688
Comparable EBITDA(1,2,3)	**305**	250	**741**	891
FFO(1,3)	**244**	204	**568**	710
FCF(1,3)	**170**	94	**314**	426
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.30)	**(0.05)**	(0.44)
FFO per share(1,3)	**0.87**	0.71	**2.00**	2.47
FCF per share(1,3)	**0.60**	0.33	**1.11**	1.48
Dividends declared per common share	**0.04**	0.04	**0.08**	0.12
Dividends declared per preferred share(4)	**0.26**	0.26	**0.52**	0.77

As at	**Sept. 30, 2019**	Dec. 31, 2018
Total assets	**9,261**	9,428
Total consolidated net debt(1,5)	**2,975**	3,141
Total long-term liabilities	**4,520**	4,414

(1) These items are not defined 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. 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.
(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.
(3) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(4) 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.
(5) Total consolidated net debt includes long-term debt including current portion, amounts due under credit facilities, tax equity, and lease obligations, net of available cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure and Liquidity section of this MD&A for more details on the composition of net debt.

Year-to-date, the overall performance of our portfolio is in line with expectations and based on the outlook for the balance of the year, the Corporation is currently tracking to achieve the upper end of the original FCF guidance of $270 - $330 million, excluding the impact of the PPA Settlements. We have revised our FCF guidance to $300 - $340 million due to strong results as well as participation in the TransAlta Renewables dividend reinvestment program, which lowers our distributions paid to subsidiaries' non-controlling interests. Reported FCF will further benefit from the receipt of $56 million from the Balancing Pool on settlement of the termination of the Sundance B and C Power Purchase Arrangements dispute.

In Alberta, our merchant assets at Canadian Coal and Wind benefited from higher year-to-date power prices. For the first nine months of the year, average power prices increased to $58 per MWh from $49 per MWh in 2018, mainly reflecting the impact of the extreme cold weather during the first quarter of 2019. Average power prices during the third quarter in Alberta decreased to $47 per MWh compared with $55 per MWh in 2018, due to lower than normal demand as a result from a cooler summer.

Operations, maintenance, and administration ("OM&A") expense for the three and nine months ended Sept. 30, 2019 decreased $6 million and $28 million, respectively, compared to the same periods in 2018. This decline in OM&A is largely due to lower salaries and contractor expenses, partially offset by higher legal fees.

To accurately reflect the year-over-year changes in comparable operating performance, we removed the one time PPA Settlements. After making these adjustments, comparable EBITDA for the three and nine months ended Sept. 30, 2019 decreased $1 million and $49 million, respectively, compared to the same periods in 2018, which was expected as a result of the expiry of the Mississauga contract and lower scheduled payments on the Poplar Creek contract. However, strong performance at the Canadian Coal and Energy Marketing segments as well as lower Corporate costs have significantly offset this expected decrease. At Canadian Coal, comparable EBITDA improved in 2019 on a year-to-date basis due to the combined impact of higher realized prices as a result of greater merchant production, increased co-firing resulting in lower fuel, carbon compliance and purchased power costs, as well as lower OM&A costs. In addition, performance from our Energy Marketing segment was stronger than the same periods in 2018, particularly from US Western and Eastern markets due to continued high levels of volatility across North American power markets. Comparable EBITDA for the nine months ended Sept. 30, 2019 was negatively impacted by the unplanned outage at US Coal during the first quarter of 2019.

Net earnings attributable to common shareholders for the three and nine months ended Sept. 30, 2019 were $51 million and a loss of $14 million, respectively. Increased earnings was largely due to the $56 million PPA Settlement received during the third quarter of 2019 as well as the reversal of a previous impairment at the Centralia plant of $151 million, which was partially offset by the $109 million increase for the decommissioning and restoration liability at the Centralia mine and the $18 million write-off of project development costs. Excluding the PPA Settlements and impairment charges and reversals in 2019 and 2018, net loss for the three and nine months ended Sept. 30, 2019 was $18 million and $83 million, respectively, which are improvements over 2018. Stronger earnings are attributable to stronger performance at Canadian Coal and Energy Marketing, strong year-to-date Alberta pricing, the Alberta tax rate reduction, lower OM&A costs, and lower interest expense, partially offset by other gains and losses.

FCF, after adjusting for the PPA Settlements, was $20 million higher for the three months ended Sept. 30, 2019 compared to the same period in 2018, mainly due to timing of capital expenditures and strong results despite significant cash flow declines from expiring contract payments. For the nine months ended Sept. 30, 2019, FCF was $11 million lower, excluding the PPA Settlements, compared with the same period in 2018, mainly due to lower comparable EBITDA, partially offset by lower distributions paid to subsidiaries' non-controlling interests. Significant changes in segmented cash flows are highlighted below:

- Excluding the PPA Settlements, Canadian Coal cash flow was $29 million and $14 million higher in the three and nine months ended Sept. 30, 2019, respectively, compared to the same periods in 2018. The increase in the quarter was mainly due to stronger comparable EBITDA and timing of capital expenditures. For the year-to-date period, strong comparable EBITDA was partially offset by higher sustaining capital spend due to planned major maintenance at Canadian Coal.
- US Coal cash flow for the third quarter of 2019 was $19 million higher than the same period in 2018, mainly due to higher comparable EBITDA. On a year-to-date basis, US Coal comparable EBITDA and cash flow was significantly lower due to an unplanned outage for one of the units during extreme market conditions driven by low temperatures and high natural gas prices in early March 2019.
- Canadian Gas cash flow in the three and nine months ended Sept. 30, 2019, was $26 million and $92 million lower, respectively, which was expected due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease.
- Energy Marketing cash flow improved by $2 million and $51 million in the three and nine months ended Sept. 30, 2019, respectively, compared to the same periods in 2018, due to higher comparable EBITDA in the year-to-date period and other cash settlements.

Significant Events

Our focus continues to be improving our operating performance and transitioning to clean power generation. The Corporation made the following progress throughout the period:

- On Oct. 30, 2019, TransAlta entered into an agreement with Kineticor Holdings Limited #2 ("Kineticor") to indirectly acquire two 230 MW Siemens F class gas turbines and related equipment for $84 million, which will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined cycle unit. The Corporation is assuming long-term non-unit contingent power purchase agreements for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada).
- On Oct. 1, 2019, TransAlta and SemCAMS Midstream ULC ("SemCAMS") announced that they have entered into definitive agreements for the development, construction and operation of a new cogeneration facility at the Kaybob South No. 3 sour gas processing plant.
- On Oct. 1, 2019, the Corporation closed the previously announced agreement with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility.
- On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in renewable energy. The total cost of the plan is expected to be approximately $2 billion which includes approximately $800 million of renewable energy projects already under construction.
- On Sept. 16, 2019, TransAlta also announced that it has adopted, based on TransAlta level deconsolidated cash flows, a Debt/EBITDA target of 3.0x or less, and a dividend policy of returning between 10% and 15% of TransAlta deconsolidated funds from operations ("Deconsolidated FFO") to common shareholders.
- On Aug. 26, 2019, the Corporation announced it was successful in the arbitration with the Balancing Pool relating to the termination of the Sundance B and C PPAs and received the full amount it was seeking to recover of $56 million, plus GST and interest.
- During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills.
- During the first nine months of the year, we purchased and cancelled 3,133,200 common shares at an average price of $8.57 per common share through our normal course issuer bid ("NCIB") program, for a total cost of $27 million.
- On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the 136.8 MW Skookumchuk Wind Energy Facility.
- On March 28, 2019, the Corporation closed its acquisition of the Antrim wind project following the receipt of required regulatory approvals.
- On March 25, 2019, the Corporation announced a $750 million investment in exchangeable securities by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for unsecured subordinated debentures.

- On March 8, 2019, the Alberta Electric System Operator ("AESO") approved the Corporation's decision to extend the mothballing of Sundance Unit 3 and 5 until Nov. 1, 2021.
- On March 4, 2019, TransAlta approved the WindCharger Battery Storage Project ("Windcharger"), an innovative 10 MW / 20 MWh energy storage project.

See the Strategic Growth and Corporate Transformation and Significant and Subsequent Events sections of this MD&A for further details.

Adjusted Availability and Production

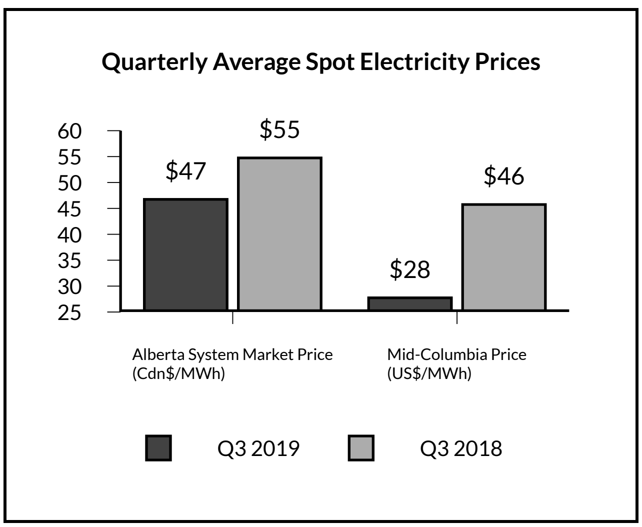
Adjusted availability for the three months ended Sept. 30, 2019 was 95.2 per cent compared to 93.7 per cent for the same period in 2018, this increase was largely due to fewer forced outages and derates at Canadian and US Coal. Adjusted availability for the nine months ended Sept. 30, 2019 was 89.5 per cent compared to 91.3 per cent for the same period in 2018. The decrease was mainly due to higher planned outages at Canadian Coal, unplanned outages and derates at US Coal and unplanned outages at Australian Gas.

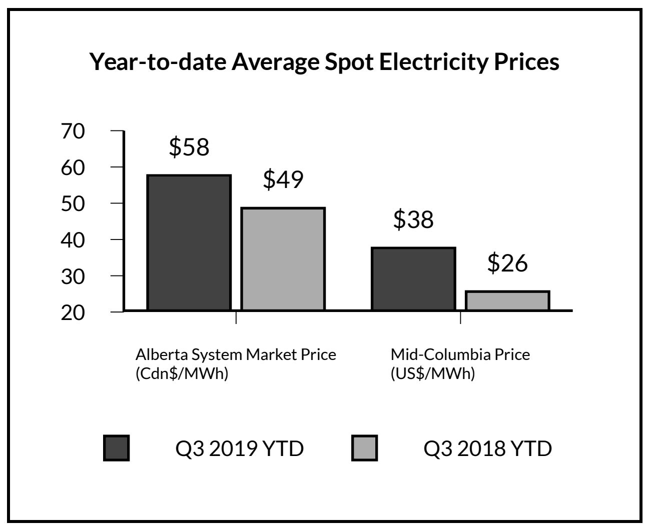
Production for the three months ended Sept. 30, 2019 was 7,558 gigawatt hours ("GWh") compared to 7,761 GWh for the same period in 2018. This decrease was largely due to lower than normal demand as a result of a cooler summer in Alberta, partially offset by strong water resources for Hydro production. Production for the nine months ended Sept. 30, 2019 was 20,918 GWh compared to 20,132 GWh for the same period in 2018. The higher year-to-date production was primarily due to a strong price environment in the Pacific Northwest during the first quarter of 2019, which resulted in higher dispatching at US Coal. This was partially offset by lower production at Canadian Coal due to higher planned outages in 2019 and the mothballing of Sundance Units 3 and 5 on April 1, 2018.

Electricity Prices

The average spot electricity price in Alberta for the three months ended Sept. 30, 2019 was lower than 2018, due to a cooler than normal summer in the province, resulting in lower demand for power. For the nine months ended Sept. 30, 2019, the average spot electricity price in Alberta increased significantly compared to 2018, primarily due to significantly below average temperatures in February and early March.

Similarly, power prices were significantly lower in the Pacific Northwest in the three months ended Sept. 30, 2019, also due to a cooler than normal summer throughout the US West. However, power prices for the nine months ended Sept. 30, 2019 remained substantially higher, on average, than 2018 mainly due to extremely high power prices in February and March of 2019.





Discussion of Consolidated Financial Results

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Those discussed below, and elsewhere in this MD&A, are not defined 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 are not necessarily comparable to a similarly titled measure of another company. 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 performance. Interest, taxes, and depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, we reclassify certain transactions to facilitate the discussion on the performance of our business:

(i) Certain assets we own in Canada 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 depreciate these assets over their expected lives;

(ii) We also reclassify the depreciation on our mining equipment from fuel and purchased power to reflect the actual cash cost of our business in our comparable EBITDA;

(iii) In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator ("IESO") relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") effective Jan. 1, 2017. Under the NUG Contract, we received fixed monthly payments until Dec. 31, 2018 with no delivery obligations. Under IFRS, for our reported results in 2016, as a result of the NUG Contract, we recognized a receivable of $207 million (discounted), a pre-tax gain of approximately $191 million net of costs to mothball the units, and accelerated depreciation of $46 million. In 2017 and 2018, on a comparable basis, we recorded the payments we received as revenues as a proxy for operating income, and depreciated the facility until Dec. 31, 2018;

(iv) On commissioning the South Hedland Power Station in Australia, 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; and

(v) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.

(vi) Asset impairment charges (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.

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

	3 months ended Sept. 30(1)		**9 months ended Sept. 30**(1)	
	2019	2018	**2019**	2018
Net earnings (loss) attributable to common shareholders (2)	**51**	(86)	**(14)**	(126)
Net earnings attributable to non-controlling interests	**16**	9	**67**	65
Preferred share dividends	**10**	10	**20**	30
Net earnings (loss)	**77**	(67)	**73**	(31)
Adjustments to reconcile net income to comparable EBITDA				
Depreciation and amortization	**148**	146	**436**	422
Foreign exchange loss	**9**	8	**18**	15
Other (gains) losses	**6**	(1)	**18**	(1)
Net interest expense	**55**	73	**161**	200
Income tax expense (recovery)	**10**	(21)	**(23)**	10
Comparable reclassifications				
Decrease in finance lease receivables	**7**	15	**19**	44
Mine depreciation included in fuel cost	**30**	35	**90**	103
Australian interest income	**1**	1	**3**	3
Unrealized (gains) losses from risk management activities	**(16)**	1	**(32)**	1
Adjustments to earnings to arrive at comparable EBITDA				
Impacts associated with Mississauga recontracting(3)	**—**	22	**—**	75
Asset impairment charge (reversal)(4)	**(22)**	38	**(22)**	50
Comparable EBITDA	**305**	250	**741**	891
Comparable EBITDA - excluding the PPA settlement	**249**	250	**685**	734

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.
(2) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(3) The Mississauga recontracting ended in 2018. The impact for the three and nine months ended Sept. 30, 2019 was a decrease to revenue of $24 million and $78 million, respectively and a decrease to fuel and purchased power and de-designated hedges of $2 million and $3 million, respectively.
(4) Asset impairment charge (reversal) for 2019 includes a $151 million impairment reversal at US Coal, partially offset by the $109 million increase for the decommissioning and restoration liability at the Centralia mine and the $18 million write-off of project development costs. 2018 includes a $38 million charge for the retirement of Sundance Unit 2, as well as a $12 million charge relating to Lakeswind and Kent Breeze.

Comparable EBITDA, after adjusting for the PPA Settlements, for the three and nine months ended Sept. 30, 2019 decreased $1 million and $49 million, respectively, compared to the same periods in 2018. We expected year-to-date comparable EBITDA to decline by $75 million as a result of the expiry of the Mississauga NUG Contract and $28 million due lower scheduled payments from Poplar Creek. In addition, year-to-date comparable EBITDA at US Coal has declined due to the unplanned outage during the first quarter of 2019. However, strong performance at the Canadian Coal and Energy Marketing segments as well as lower Corporate costs have significantly offset these decreases.

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 an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends, or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. 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 Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Cash flow from operating activities[1]	**328**	159	**668**	688
Change in non-cash operating working capital balances	**(92)**	29	**(122)**	(25)
Cash flow from operations before changes in working capital	**236**	188	**546**	663
Adjustment:				
Decrease in finance lease receivable	**7**	15	**19**	44
Other	**1**	1	**3**	3
FFO	**244**	204	**568**	710
Deduct:				
Sustaining capital[2]	**(25)**	(44)	**(111)**	(98)
Productivity capital	**(4)**	(6)	**(7)**	(12)
Dividends paid on preferred shares	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(30)**	(43)	**(89)**	(126)
Payments on lease obligations[2]	**(5)**	(5)	**(16)**	(14)
Other	**—**	(2)	**(1)**	(4)
FCF	**170**	94	**314**	426
Weighted average number of common shares outstanding in the year	**282**	287	**284**	287
FFO per share	**0.87**	0.71	**2.00**	2.47
FCF per share	**0.60**	0.33	**1.11**	1.48

(1) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. 2018 results have been revised to reflect these changes.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Comparable EBITDA[1]	**305**	250	**741**	891
Interest expense	**(45)**	(45)	**(133)**	(147)
Provisions	**3**	2	**14**	1
Current income tax (expense) recovery	**(14)**	1	**(28)**	(18)
Realized foreign exchange gain (loss)	**—**	(2)	**(7)**	4
Decommissioning and restoration costs settled	**(9)**	(10)	**(24)**	(23)
Other cash and non-cash items	**4**	8	**5**	2
FFO	**244**	204	**568**	710
Deduct:				
Sustaining capital[2]	**(25)**	(44)	**(111)**	(98)
Productivity capital	**(4)**	(6)	**(7)**	(12)
Dividends paid on preferred shares	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(30)**	(43)	**(89)**	(126)
Payments on lease obligations[2]	**(5)**	(5)	**(16)**	(14)
Other	**—**	(2)	**(1)**	(4)
FCF	**170**	94	**314**	426

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change. 2018 includes $157 million received from the Balancing Pool in the first quarter of 2018, for the early termination of Sundance B and C PPAs and 2019 results include $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. 2018 results have been revised to reflect these changes.

Supplemental disclosure	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
FFO - excluding the PPA Settlements	188	204	512	553
FCF - excluding the PPA Settlements	114	94	258	269
FFO per share - excluding the PPA Settlements	0.67	0.71	1.80	1.93
FCF per share - excluding the PPA Settlements	0.40	0.33	0.91	0.94

After adjusting for the PPA Settlements, FFO was down $16 million and $41 million over the three and nine months ended Sept. 30, 2018, respectively. The three month period was down from the previous period primarily due to lower comparable EBITDA of $1 million and an increase in current income tax expense. The nine month period was down due to lower comparable EBITDA of $49 million, an increase in current income tax expense, partially offset by lower interest expense and favourable timing of cash settlements.

Segmented Comparable Results

Segmented cash flow generated by the business, shown in the table below, measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, provisions, and non-cash mark-to-market gains or losses. This is the cash flow available to: pay our interest and cash taxes, make distributions to our non-controlling partners and dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Segmented cash flow[1]				
Canadian Coal[2]	**117**	32	**177**	264
US Coal	**30**	11	**29**	42
Canadian Gas	**29**	55	**77**	169
Australian Gas	**28**	30	**87**	92
Wind and Solar	**28**	24	**134**	137
Hydro	**24**	22	**80**	85
Generation cash flow	**256**	174	**584**	789
Energy Marketing	**30**	32	**74**	23
Corporate	**(22)**	(25)	**(63)**	(73)
Total comparable cash flow	**264**	181	**595**	739
Total comparable cash flow - excluding PPA settlement	**208**	181	**539**	582

(1) Segmented cash flow is a non-IFRS measure.
(2) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.

Canadian Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Availability (%)	**96.8**	94.4	**89.5**	91.9
Contract production (GWh)	**1,700**	1,897	**5,186**	6,855
Merchant production (GWh)	**1,373**	1,519	**4,395**	3,693
Total production (GWh)	**3,073**	3,416	**9,581**	10,548
Gross installed capacity (MW)(1)	**3,231**	3,231	**3,231**	3,231
Revenues(2)	**205**	226	**626**	677
Fuel, carbon costs, and purchased power(2)	**99**	123	**336**	387
Comparable gross margin	**106**	103	**290**	290
Operations, maintenance, and administration	**34**	37	**102**	127
Taxes, other than income taxes	**3**	3	**10**	10
Termination of Sundance B and C PPAs	**(56)**	—	**(56)**	(157)
Net other operating income	**(10)**	(10)	**(30)**	(31)
Comparable EBITDA(2)	**135**	73	**264**	341
Deduct:				
Sustaining capital:				
Routine capital	**4**	5	**11**	12
Mine capital	**8**	21	**18**	32
Planned major maintenance	**1**	3	**33**	4
Total sustaining capital expenditures(3)	**13**	29	**62**	48
Productivity capital	**2**	4	**5**	7
Total sustaining and productivity capital expenditures	**15**	33	**67**	55
Provisions	**(4)**	(1)	**(3)**	(3)
Payments on lease obligations(3)	**3**	4	**11**	11
Decommissioning and restoration costs settled	**4**	5	**12**	14
Canadian Coal cash flow	**117**	32	**177**	264

(1) Includes units temporarily mothballed (774 MW Sundance Units 3 and 5).
(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.
(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line in arriving at segmented cash flow.

	3 months ended Sept. 30		9 months ended Sept. 30	
Supplemental disclosure	**2019**	2018	**2019**	2018
Comparable EBITDA - excluding the PPA settlement	**79**	73	**208**	184
Canadian Coal cash flow - excluding the PPA settlement	**61**	32	**121**	107

Availability for the third quarter increased compared to the same period in 2018, due to fewer forced outages and derates. Availability for the year-to-date period decreased compared to the same period in 2018, mainly due to higher planned maintenance outages during the second quarter of 2019. In 2018, there were no planned maintenance outages in this same period.

Production for the three and nine months ended Sept. 30, 2019 decreased 343 GWh and 967 GWh, respectively, compared to the same periods in 2018. Lower total production in the third quarter of 2019 was a result of weaker market conditions. Lower total production in the year-to-date period was due to planned maintenance outages mainly in the second quarter of 2019, on the Sundance 4, Keephills 1 and Keephills 2 units. Lower contract production was partially offset by higher merchant production in the year-to-date period.

Revenue for the three and nine months ended Sept. 30, 2019 decreased by $21 million and $51 million, respectively, compared to the same periods in 2018. Revenue for the third quarter decreased due to lower market prices. Revenue for the year-to-date period decreased mainly due to lower production as a result of the termination of the Sundance B and C PPAs on March 31, 2018, partially offset by higher market prices in the first half of the year.

In the three and nine months ended Sept. 30, 2019, revenue per MWh of production increased to approximately $67 per MWh and $65 per MWh, respectively, compared with $66 per MWh and $64 per MWh, respectively, for the same periods in 2018. Revenues in the first quarter of 2018 included the Sundance B and C PPA revenue as well as the passthrough revenues associated with carbon compliance costs, which are no longer recoverable on the Sundance units as the PPAs have been terminated.

Fuel, carbon compliance costs, and purchased power costs per MWh of production were lower for the three and nine months ended Sept. 30, 2019, at $32 per MWh and $35 per MWh, respectively, compared with $36 per MWh and $37 per MWh, respectively, in the same periods in 2018. Consequently, comparable gross margin per MWh for the three and nine months ended Sept. 30, 2019, improved by $4/MWh and $3/MWh, respectively, compared to the same periods in 2018.

We continued to co-fire with natural gas at the merchant units, when economical. Co-firing lowers the carbon compliance costs as the GHG emissions are lower. In addition, fuel costs can be lower by co-firing, depending on the market price for natural gas. We expect the level of co-firing to increase as the firm contract to transport natural gas on the Pioneer Pipeline begins on Nov. 1, 2019, which substantially increases gas quantities available to us. See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

OM&A costs were $3 million and $25 million lower in the three and nine months ended Sept. 30, 2019 compared to 2018, respectively. 2019 OM&A reflects the full impact of cost reductions progressively implemented over the preceding year. These cost reductions arose from a combination of factors including fewer units operating, lower capacity factor operation on merchant units, co-firing with gas, and operations and maintenance work optimization.

Excluding the PPA Settlements, comparable EBITDA for the three and nine months ended Sept. 30, 2019 was $6 million and $24 million higher, respectively, compared with the same periods in 2018. This largely reflects the combined impact of higher prices in the first half of the year, lower fuel, carbon compliance and purchased power costs as well as lower OM&A costs.

Sustaining and productivity capital expenditures decreased $18 million in the third quarter of 2019 compared to the same period in 2018, due to pit development costs that occurred in 2018 at our Highvale Mine. Sustaining and productivity capital expenditures increased $12 million for the year-to-date period compared to the same period in 2018, as capital increased due to planned power plant maintenance outages in the first half of 2019. There were no planned maintenance outages on operated power plants in the same periods in 2018.

Canadian Coal cash flow for the three months ended Sept. 30, 2019, increased by $29 million (excluding the PPA Settlements) compared to the same period in 2018, mainly due to higher comparable EBITDA and the timing of capital expenditures. Cash flow for the nine months ended Sept. 30, 2019, increased by $14 million (excluding the PPA Settlements) compared to the same period in 2018, mainly due to higher comparable EBITDA partially offset by increased year-to-date sustaining capital expenditures associated with the planned maintenance outages in 2019.

US Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Availability (%)	**93.8**	90.2	**68.7**	51.8
Adjusted availability (%)(1)	**93.8**	90.2	**81.5**	84.5
Contract sales (GWh)	**839**	839	**2,489**	2,490
Merchant sales (GWh)	**2,494**	2,400	**5,065**	3,239
Purchased power (GWh)	**(997)**	(954)	**(2,847)**	(2,642)
Total production (GWh)	**2,336**	2,285	**4,707**	3,087
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues(2)	**161**	157	**392**	300
Fuel and purchased power	**107**	122	**295**	186
Comparable gross margin	**54**	35	**97**	114
Operations, maintenance, and administration	**18**	17	**50**	44
Taxes, other than income taxes	**1**	1	**3**	3
Comparable EBITDA(2)	**35**	17	**44**	67
Deduct:				
Sustaining capital:				
Routine capital	**1**	—	**2**	2
Planned major maintenance	**(1)**	—	**3**	11
Total sustaining capital expenditures(3)	**—**	—	**5**	13
Productivity capital	**1**	—	**1**	—
Total sustaining and productivity capital expenditures(3)	**1**	—	**6**	13
Payments on lease obligations(3)	**—**	1	**—**	3
Decommissioning and restoration costs settled	**4**	5	**9**	9
US Coal cash flow	**30**	11	**29**	42

(1) Adjusted for dispatch optimization.
(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.
(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line. The contractual arrangement that was accounted for as a finance lease in 2018 and prior periods is not considered a lease under IFRS 16. Accordingly, the costs are reflected in fuel and purchased power and there are no payments on lease obligations from Jan. 1, 2019.

Adjusted availability for the three months ended Sept. 30, 2019 increased compared to the same period in 2018, due to fewer forced outages. Adjusted availability for the nine months ended Sept. 30, 2019 was down compared to the same period in 2018, due to higher forced outages and derates. Unit 1 operated with a derate due to blocked precipitator hoppers impacting the first half of 2019. This derate was resolved when the unit was offline during the second quarter of 2019.

Production for the three months ended Sept. 30, 2019 was consistent with the same period in 2018. Production for the nine months ended Sept. 30, 2019 increased 1,620 GWh compared to the same period in 2018, due mainly to higher merchant pricing in the first half of 2019 and the timing of dispatch optimization. In 2019, both Centralia units remained in service into April due to higher prices in the Pacific Northwest, whereas in 2018, both Centralia units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In 2018, we performed major maintenance on both units during that time.

OM&A costs for the three months ended Sept. 30, 2019 were consistent with the same period in 2018 but increased by $6 million for the nine months ended Sept. 30, 2019, compared to the same period in 2018. The year-to-date increase is largely due to increased maintenance as a result of higher forced outages and derates in the period.

Comparable EBITDA for the three months ended Sept. 30, 2019, increased by $18 million compared to the same period in 2018, due to strong availability of units. Comparable EBITDA for the nine months ended Sept. 30, 2019, was down $23 million compared to the same period in 2018. During an isolated and extreme pricing event in March, Centralia was unable to commit one of its units to physical production for day ahead supply due to an unplanned forced outage repair. As a result, the Corporation incurred cash losses of $25 million on its day ahead hedging position.

Sustaining and productivity capital expenditures for the three months ended Sept. 30, 2019 increased by $1 million compared to the same period in 2018, mainly due to timing of capital expenditures. Sustaining and productivity capital expenditures for the nine months ended Sept. 30, 2019 decreased by $7 million compared to the same period in 2018, as there was less planned outage work performed in 2019.

US Coal cash flow for the third quarter of 2019 was $19 million higher than the same period in 2018, mainly due to higher comparable EBITDA. Year-to-date cash flow declined by $13 million compared to the same period in 2018, as the cash loss in March 2019 (described above), was partially offset by strong availability and comparable EBITDA in the second and third quarters of 2019 as well as lower planned major maintenance in 2019.

Canadian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Availability (%)	**93.4**	95.1	**94.0**	92.8
Contract production (GWh)	**400**	431	**1,260**	1,172
Merchant production (GWh)(1)	**15**	61	**115**	132
Total production (GWh)	**415**	492	**1,375**	1,304
Gross installed capacity (MW)	**945**	953	**945**	953
Revenues(2)	**54**	94	**181**	290
Fuel and purchased power	**14**	25	**57**	73
Comparable gross margin	**40**	69	**124**	217
Operations, maintenance, and administration	**11**	11	**33**	36
Taxes, other than income taxes	**—**	—	**1**	1
Net other operating income	**(1)**	—	**(1)**	—
Comparable EBITDA(2)	**30**	58	**91**	180
Deduct:				
Sustaining capital:				
Routine capital	**—**	—	**8**	2
Planned major maintenance	**1**	2	**6**	9
Total sustaining capital expenditures	**1**	2	**14**	11
Productivity capital	**—**	1	**—**	2
Total sustaining and productivity capital expenditures	**1**	3	**14**	13
Provisions and other	**—**	—	**—**	(2)
Canadian Gas cash flow	**29**	55	**77**	169

(1) Includes purchased power, which is used for dispatch optimization, when economical.
(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Availability for the three months ended Sept. 30, 2019 decreased compared to the same period in 2018, primarily due to higher planned outages. Availability for the nine months ended Sept. 30, 2019 increased compared to the same period in 2018, primarily due to lower planned outages at Fort Saskatchewan in the second quarter and Sarnia during the first quarter.

Production for the three months ended Sept. 30, 2019 decreased 77 GWh compared to the same period in 2018, due to unfavorable market conditions in Ontario and higher planned outages. Production for the nine months ended Sept. 30, 2019 increased 71 GWh compared to the same period in 2018, mainly due to higher customer and market demand and lower planned outages, partially offset higher unplanned outages.

Comparable EBITDA for the three and nine months ended Sept. 30, 2019 decreased by $28 million and $89 million, respectively, compared to the same periods in 2018, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease. Additionally, year-to-date results have benefited from lower OM&A compared to the prior year, and lower fuel costs at Sarnia due to less steam demand from customer planned outages. In the three and nine months ended Sept. 30, 2018, comparable EBITDA included $31 million and $103 million of EBITDA, respectively, from the Mississauga and Poplar Creek contracts.

Sustaining and productivity capital in the third quarter of 2019 decreased by $2 million compared to the same period in 2018, due to lower planned major maintenance costs. Sustaining and productivity capital for the nine months ended Sept. 30, 2019 increased $1 million compared to the same period in 2018, due to the timing of capital spares purchases for Sarnia.

Cash flow at Canadian Gas decreased by $26 million and $92 million in the third quarter and year-to-date periods of 2019, respectively, compared to 2018, mainly due to lower comparable EBITDA.

Australian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Availability (%)	**97.7**	98.0	**89.9**	94.6
Contract production (GWh)	**450**	444	**1,369**	1,357
Gross installed capacity (MW)	**450**	450	**450**	450
Revenues	**39**	41	**120**	123
Fuel and purchased power	**1**	1	**3**	3
Comparable gross margin	**38**	40	**117**	120
Operations, maintenance, and administration	**9**	10	**27**	28
Comparable EBITDA	**29**	30	**90**	92
Deduct:				
Sustaining capital:				
Planned major maintenance	**1**	—	**3**	—
Total sustaining and productivity capital expenditures	**1**	—	**3**	—
Australian Gas cash flow	**28**	30	**87**	92

Availability for the three months ended Sept. 30, 2019 was consistent with 2018. Availability for the nine months ended Sept. 30, 2019 decreased compared to the same period in 2018, primarily due to unplanned outages.

Production for the three and nine months ended Sept. 30, 2019 was consistent with the same periods in 2018. Our contracts in Australia are capacity contracts, and our results are not directly impacted by changes in electricity generation.

Comparable EBITDA for the three and nine months ended Sept. 30, 2019 was consistent with the same periods in 2018, which was expected due to the nature of our contracts.

Sustaining capital for the three and nine months ended Sept. 30, 2019 increased by $1 million and $3 million compared with the same periods in 2018, due to planned major maintenance at our Southern Cross facility.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Availability (%)	**93.9**	93.9	**94.7**	94.9
Contract production (GWh)	**396**	388	**1,671**	1,666
Merchant production (GWh)	**174**	137	**578**	639
Total production (GWh)	**570**	525	**2,249**	2,305
Gross installed capacity (MW)	**1,382**	1,363	**1,382**	1,363
Revenues(1)	**53**	47	**201**	202
Fuel and purchased power	**4**	3	**11**	13
Comparable gross margin	**49**	44	**190**	189
Operations, maintenance, and administration	**12**	14	**37**	38
Taxes, other than income taxes	**2**	2	**6**	6
Net other operating income	**—**	(6)	**(4)**	(6)
Comparable EBITDA(1)	**35**	34	**151**	151
Deduct:				
Sustaining capital:				
Routine capital	**1**	3	**1**	3
Planned major maintenance	**4**	1	**9**	5
Total sustaining and productivity capital expenditures	**5**	4	**10**	8
Payments on lease obligations(2)	**2**	—	**2**	—
Decommissioning and restoration costs settled	**—**	—	**1**	—
Other(3)	**—**	6	**4**	6
Wind and Solar cash flow	**28**	24	**134**	137

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.
(2) On implementation of IFRS 16 in 2019, we included principal payments on lease obligations as a separate line.
(3) Relates to insurance proceeds included in net other operating income. 2018 Wind and Solar cash flow was adjusted to reflect the insurance proceeds received in the third quarter of 2018.

Availability for the three and nine months ended Sept. 30, 2019 was consistent with the same periods in 2018.

Production for the three months ended Sept. 30, 2019 increased by 45 GWh compared to the same period in 2018, mainly due to higher wind resources in Western Canada. Production for the nine months ended Sept. 30, 2019 decreased by 56 GWh compared to the same period in 2018, mainly due to lower wind resources in the first half of the year in Western Canada and the United States, partially offset by higher wind resources in Eastern Canada.

Comparable EBITDA for the three and nine months ended Sept. 30, 2019 was consistent with the same periods in 2018. In the third quarter, higher overall production, higher sales of green attributes and lower OM&A costs were offset by lower insurance proceeds. For the year-to-date period, higher sales of green attributes and lower OM&A costs were offset by lower production.

Wind and Solar cash flow for the three months ended Sept. 30, 2019 increased by $4 million compared to the same period in 2018, due to higher comparable EBITDA, after adjusting for the insurance proceeds received in the third quarter of 2018. Cash flow decreased by $3 million in the nine months ended Sept. 30, 2019 compared to the same period in 2018, due to higher capital expenditures and payments on lease obligations.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Production				
Energy contracted				
Alberta hydro PPA assets (GWh)(1)	**578**	459	**1,313**	1,189
Other hydro energy (GWh)(1)	**106**	100	**266**	269
Energy merchant				
Other hydro energy (GWh)	**30**	40	**58**	73
Total energy production (GWh)	**714**	599	**1,637**	1,531
Ancillary services volumes (GWh)(2)	**732**	737	**2,301**	2,559
Gross installed capacity (MW)	**926**	926	**926**	926
Revenues				
Alberta hydro PPA assets energy	**28**	29	**84**	70
Alberta hydro PPA assets ancillary services	**17**	23	**74**	83
Capacity payments received under Alberta hydro PPA(3)	**15**	14	**43**	42
Other revenue(4)	**12**	12	**35**	35
Total gross revenues	**72**	78	**236**	230
Net payment relating to Alberta hydro PPA	**(32)**	(41)	**(110)**	(103)
Revenues	**40**	37	**126**	127
Fuel and purchased power	**3**	2	**6**	5
Comparable gross margin	**37**	35	**120**	122
Operations, maintenance, and administration	**8**	8	**26**	27
Taxes, other than income taxes	**1**	1	**2**	3
Comparable EBITDA(5)	**28**	26	**92**	92
Deduct:				
Sustaining capital:				
Routine capital	**1**	1	**3**	2
Planned major maintenance	**1**	3	**6**	5
Total sustaining capital expenditures	**2**	4	**9**	7
Productivity capital	1	—	**1**	—
Total sustaining and productivity capital expenditures	**3**	4	**10**	7
Decommissioning and restoration costs settled	1	—	2	—
Hydro cash flow	**24**	22	**80**	85

(1) Alberta hydro PPA assets include 13 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPAs.
(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer. The PPA expires in 2020.
(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements, including the flood mitigation agreement with the Alberta government and black start services.
(5) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change. However, there was no impact to Hydro's comparable EBITDA.

Production for the three and nine months ended Sept. 30, 2019 increased by 115 GWh and 106 GWh, respectively, compared to the same periods in 2018 mainly due to high water resources.

Total gross revenues decreased by $6 million the three months ended Sept. 30, 2019 compared to the same period in 2018, due to unfavourable power and ancillary services pricing. Total gross revenues increased by $6 million for the nine months ended Sept. 30, 2019 as favourable energy sales more than offset lower ancillary services revenue. After net payments relating to the Alberta hydro PPA, comparable EBITDA for the three and nine months ended Sept. 30, 2019 was consistent with the same periods in 2018.

Sustaining and productivity capital expenditures for the three months ended Sept. 30, 2019 decreased $1 million compared to the same period in 2018, due to timing of capital expenditures. Sustaining and productivity capital expenditures for the nine months ended Sept. 30, 2019 increased $3 million compared to the same period in 2018, due to an overhaul at our Rundle and Three Sisters facilities.

Hydro cash flow increased by $2 million for the three months ended Sept. 30, 2019 compared to the same period in 2018, mainly due to timing of capital expenditures. Cash flow decreased by $5 million for the nine months ended Sept. 30, 2019 compared to the same period in 2018, due to higher planned major maintenance and increased decommissioning and restoration costs in 2019.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Revenues and gross margin(1)	**36**	35	**85**	44
Operations, maintenance, and administration	**5**	4	**22**	17
Comparable EBITDA(1)	**31**	31	**63**	27
Deduct:				
Provisions and other	**1**	(1)	**(11)**	4
Energy Marketing cash flow	**30**	32	**74**	23

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

For the three months ended Sept. 30, 2019, comparable EBITDA was consistent with the same period in 2018, due to strong results in both periods. For the nine months ended Sept. 30, 2019, comparable EBITDA was $36 million higher compared to the same period in 2018 due to strong results across all markets with particularly strong performance from US Western and Eastern markets due to continued high levels of volatility across North American power markets. OM&A increased due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short term arbitrage opportunities in the markets we trade.

Energy Marketing cash flow for the three months ended Sept. 30, 2019 was consistent with the same period in 2018. For the nine months ended Sept. 30, 2019, cash flow improved by $51 million, due to higher comparable EBITDA and other cash settlements.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Operations, maintenance, and administration	**(17)**	(19)	**(51)**	(59)
Taxes, other than income taxes	**(1)**	—	**(1)**	—
Net other operating income (loss)	**—**	—	**(2)**	—
Comparable EBITDA	**(18)**	(19)	**(54)**	(59)
Deduct:				
Sustaining capital:				
Routine capital	3	5	8	11
Total sustaining capital expenditures	**3**	**5**	**8**	**11**
Productivity capital	—	1	—	3
Total sustaining and productivity capital expenditures	**3**	6	**8**	14
Payments on lease obligations(1)	**1**	—	**3**	—
Other	**—**	—	**(2)**	—
Corporate cash flow	**(22)**	(25)	**(63)**	(73)

(1) On implementation of IFRS 16 in 2019, we have included interest and principal payments on lease obligations as a separate line.

During the three months ended Sept. 30, 2019, OM&A costs decreased by $2 million, due to cost saving efficiencies, partially offset by higher legal fees. For the nine months ended Sept. 30, 2019, OM&A costs decreased by $8 million, primarily due to the year-to-date realized net gain of $8 million from the total return swap on our share-based payment plans, payments on leases that were capitalized on implementation of IFRS 16 and other cost saving efficiencies, partially offset by higher legal fees. The losses on the total return swap realized during the second and third quarters of 2019 partially offset the gain realized in the first quarter of 2019. A portion of the settlement cost of our share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit ratings 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 under IFRS, and may not be comparable to those used by other entities or by rating agencies. We are focused on strengthening our financial position and flexibility and aim to meet all our target ranges.

FFO Before Interest to Adjusted Interest Coverage

For the twelve months ended	Sept. 30, 2019	Dec. 31, 2018
FFO(1)	785	927
Less: PPA Settlements	(56)	(157)
Add: Interest on debt, exchangeable securities and lease obligations, net of interest income and capitalized interest	164	174
FFO before interest	**893**	944
Interest on debt, exchangeable securities and lease obligations, net of interest income	169	176
Add: 50 per cent of dividends paid on preferred shares	20	20
Adjusted interest	**189**	196
FFO before interest to adjusted interest coverage (times)	**4.7**	4.8

(1) See Discussion of Financial Results for reconciliation of cash flow from operating activities to FFO for the nine months ended Sept. 30, 2019 and 2018. These amounts are used to calculate the twelve months ended FFO by taking the current year-to-date FFO plus 2018 FFO minus the prior year-to-date FFO.

Our target for FFO before interest to adjusted interest coverage is four to five times. While both periods are within our target range, the ratio decreased slightly at Sept. 30, 2019 compared to Dec. 31, 2018, mainly due to lower FFO before interest.

Adjusted FFO to Adjusted Net Debt

As at	Sept. 30, 2019	Dec. 31, 2018
FFO(1,2)	785	927
Less: PPA Settlements(1)	(56)	(157)
Less: 50 per cent of dividends paid on preferred shares(1)	(20)	(20)
Adjusted FFO	**709**	750
Period-end long-term debt(3)	2,995	3,267
Exchangeable securities	325	—
Less: Cash and cash equivalents	(326)	(89)
Less: Principal portion of TransAlta OCP restricted cash	(10)	(27)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt(4)	(9)	(10)
Adjusted net debt	**3,446**	3,612
Adjusted FFO to adjusted net debt (%)	**20.6**	20.8

(1) Last 12 months.
(2) See Discussion of Financial Results for reconciliation of cash flow from operating activities to FFO for the nine months ended Sept. 30, 2019 and 2018. These amounts are used to calculate the twelve months ended FFO by taking the current year-to-date FFO plus 2018 FFO minus the prior year-to-date FFO.
(3) Includes lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2019 and Dec. 31, 2018.

Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent. Our adjusted FFO to adjusted net debt declined due to lower adjusted FFO compared with 2018, partially offset by lower adjusted net debt.

Adjusted Net Debt to Adjusted Comparable EBITDA

As at	Sept. 30, 2019	Dec. 31, 2018
Period-end long-term debt[1]	**2,995**	3,267
Exchangeable securities	**325**	—
Less: Cash and cash equivalents	**(326)**	(89)
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	(27)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[2]	**(9)**	(10)
Adjusted net debt	**3,446**	3,612
Comparable EBITDA[3, 4]	**1,002**	1,152
Less: PPA Settlements	**(56)**	(157)
Adjusted comparable EBITDA[3, 4]	**946**	995
Adjusted net debt to comparable EBITDA[3, 4] (times)	**3.6**	3.6

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2019 and Dec. 31, 2018.
(3) Last 12 months.
(4) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Our target for adjusted net debt to adjusted comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio remained consistent with 2018 as lower adjusted comparable EBITDA was partially offset by lower adjusted net debt.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews Net Debt to Adjusted 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 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.

	Sept. 30, 2019	December 31, 2018
Period-end long-term debt[1]	**2,995**	3,267
Exchangeable securities	**325**	—
Less: Cash and cash equivalents	**(326)**	(89)
Less: Principal portion of OCP restricted cash	**(10)**	(27)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[2]	**(9)**	(10)
Less: TransAlta Renewables long-term debt	**(916)**	(932)
Less: US tax equity financing[3]	**(24)**	(28)
Deconsolidated net debt	**2,506**	2,652
Comparable EBITDA[4, 5]	**1,002**	1,152
Less: PPA Settlements[4]	**(56)**	(157)
Less: TransAlta Renewables comparable EBITDA[4]	**(447)**	(430)
Less: TA Cogen comparable EBITDA[4]	**(113)**	(181)
Add: Dividend from TransAlta Renewables[4]	**151**	151
Add: Dividend from TA Cogen[4]	**57**	86
Deconsolidated comparable EBITDA [4, 5]	**594**	621
Deconsolidated net debt to deconsolidated comparable EBITDA[4, 5] (times)	**4.2**	4.3

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2019 and Dec. 31, 2018.
(3) Relates to assets where TransAlta Renewables has economic interests.
(4) Last 12 months.
(5) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Our target for deconsolidated net debt to deconsolidated comparable EBITDA is 2.5 to 3.0 times by the end of 2021. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio was consistent with 2018, as lower deconsolidated net debt was offset by lower deconsolidated comparable EBITDA.

Deconsolidated FFO

During the third quarter of 2019, the Corporation implemented a new dividend policy which aims 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 under IFRS, and may not be comparable to those used by other entities or by rating agencies. Deconsolidated FFO for the three and nine months ended Sept. 30 is detailed below:

	3 months ended Sept. 30, 2019			3 months ended Sept. 30, 2018		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**328**	**75**		159	78	
Change in non-cash operating working capital balances	**(92)**	**(26)**		29	(16)	
Cash flow from operations before changes in working capital	**236**	**49**		188	62	
Adjustments:						
Decrease in finance lease receivable	**7**	**—**		15	—	
Finance and interest income - economic interests	**—**	**(9)**		—	(29)	
AFFO - economic interests	**—**	**34**		—	43	
Other	**1**	**—**		1	—	
FFO	**244**	**74**	**170**	204	76	128
Dividend from TransAlta Renewables			**38**			37
Distributions to TA Cogen			**(12)**			(23)
Less: PPA Settlements			**(56)**			—
Deconsolidated TransAlta FFO			**140**			142

	9 months ended Sept. 30, 2019			9 months ended Sept. 30, 2018		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**668**	**258**		688	282	
Change in non-cash operating working capital balances	**(122)**	**(48)**		(25)	(15)	
Cash flow from operations before changes in working capital	**546**	**210**		663	267	
Adjustments:						
Decrease in finance lease receivable	**19**	**—**		44	—	
Finance and interest income - economic interests	**—**	**(48)**		—	(125)	
AFFO - economic interests	**—**	**107**		—	116	
Other	**3**	**—**		3	—	
FFO	**568**	**269**	**299**	710	258	452
Dividend from TransAlta Renewables			**113**			113
Distributions to TA Cogen			**(33)**			(62)
Less: PPA Settlements			**(56)**			(157)
Deconsolidated TransAlta FFO			**323**			346

Strategic Growth and Corporate Transformation

Clean Energy Investment Plan

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in onsite generation and renewable energy. TransAlta is currently pursuing opportunities of up to approximately $1.9 billion as part of this plan, including approximately $800 million of renewable energy projects already under construction.

TransAlta's plan included converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The Corporation is also advancing permitting to convert one, or possibly two, of its units to highly efficient combined cycle natural gas units. The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of the Alberta thermal assets; and
- Significantly reducing air emissions and costs.

The Corporation's Clean Energy Investment Plan also consists of the four wind projects in the United States and Alberta that are currently under construction and a cogeneration facility. These projects are underpinned by long-term power purchase agreements with highly creditworthy counterparties.

The Clean Energy Investment Plan will be funded from the cash raised earlier this year through the strategic investment with an affiliate of Brookfield Renewable Partners, cash generated from operations, and raising capital through TransAlta Renewables.

Coal-to-Gas Conversions

During the first quarter of 2019, we issued Limited Notice to Proceed ("LNTP") for the coal-to-gas conversion on Sundance Unit 6 and on July 4, 2019, we issued Full Notice to Proceed ("FNTP") for this unit. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020. During the third quarter, we issued LNTP for Keephills Unit 2 and expect to issue LNTP for Keephills Unit 3 later in 2019 and FNTP for the units later in 2019 and in early 2020, respectively. We expect to complete the conversion of these units in 2021 and 2022. The cost to convert each unit is expected to be approximately $30 to $35 million per unit. In 2019, we expect to incur costs ranging from $30 million to $40 million to maximize our ability to co-fire gas more consistently at up to 30% of rated capacity and for advancing our coal-to-gas conversions.

Repowered Combined Cycle Conversions

We are permitting to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined cycle units. Repowering is expected to cost 40% lower than a new combined cycle facility while achieving a similar heat rate.

These units will either co-fire until repowered or potentially be converted to 100% gas via a boiler conversion, as the carbon savings are significant. The plan assumes there are no delays in securing the natural gas supply requirements, which may result from regulatory or other constraints.

On Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F class gas turbines and related equipment for $84 million. These turbines will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined cycle unit. The Corporation is assuming long-term non-unit contingent power purchase agreements for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada). We expect to issue LNTP in 2020 and FNTP in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million, well below a greenfield combined cycle project. In conjunction with the Sundance Unit 5 permitting, we are also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined cycle unit, depending on market fundamentals.

Pioneer Gas Pipeline Partnership

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas commenced flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater and TransAlta each own a 50 per cent interest in the Pioneer Pipeline which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, was approximately $100 million.

Kaybob Cogeneration Project

On Oct. 1, 2019, TransAlta and SemCAMS announced that they have entered into definitive agreements to develop, construct and operate a cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 to $115 million and the project is expected to deliver approximately

$18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS will purchase a fifty per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

The highly efficient cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta Power market by TransAlta. The agreement contemplates an automatic 7-year extension subject to certain termination rights. The development of the cogeneration facility at Kaybob South No. 3 will eliminate the need for traditional boilers and reduce annual carbon emissions of the operation by approximately 100,000 tonnes CO2e, which is equivalent to removing 20,000 vehicles off Alberta roads.

US Wind Projects
On Feb. 20, 2018, TransAlta Renewables announced that it had entered into an arrangement to acquire interests in two construction-ready wind projects in the United States. Construction of the projects are underway. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project. Cost estimates for the US Wind Projects have been reforecasted to US$250 million to US$270 million (including capitalized interest expense), primarily due to construction and weather related impacts as well as higher interconnection costs. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by a subsidiary of TransAlta or by subscribing for interest-bearing promissory notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs using its existing liquidity and tax equity financing. Turbine erection and commissioning is progressing at both projects. Both Big Level and Antrim are expected to be fully operational during the fourth quarter of 2019. See the Significant and Subsequent Events section of this MD&A for further details.

Windrise Wind Project
On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta and is expected to cost approximately $270 million to $285 million. The project development work is on schedule as it is progressing through the permitting process and is on track to reach commercial operation during the first half of 2021.

WindCharger Project
During the first quarter of 2019, TransAlta approved the WindCharger project, an innovative 10 MW / 20 MWh energy storage project. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview Wind Farm Substation. WindCharger will store energy produced by the nearby Summerview II Wind Farm and discharge into the Alberta Electricity Grid at times of high-peak demand. This project is expected to be the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the Alberta Utilities Commission, have been submitted with approvals expected during the fourth quarter of 2019. TransAlta is in the process of completing detailed design and engineering and procuring long-lead equipment. Construction is on-track to begin in March 2020 with a commercial operation date expected within the first half of 2020. The total expected cost of the project to TransAlta is $7 million to $8 million.

Skookumchuck Wind Project
On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW wind facility currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with Puget Sound Energy. TransAlta will make its investment when the facility reaches its commercial operation date, which is expected to be in the first quarter of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be $150 to $160 million.

Project Greenlight
Project Greenlight is a multi-year program to transform our business and the delivery of the Corporation's strategy. Business units are focusing both on cash flow improvements and the way the Corporation is delivering sustainable value. Through this program we delivered on projects that improved performance by improving generation efficiency, improving heat rates, lowering fuel costs, reducing GHG emissions, reducing operating and maintenance costs, optimizing our capital spend, avoiding new costs, reducing overhead costs and financing costs, improving working capital, monetizing assets, streamlining processes and achieving efficiencies.

The success of this project has enabled financial flexibility for new investments and as we proceed with plans to embed the transformation process into the business, we expect to continue to realize new value through innovation and process improvements.

Significant and Subsequent Events

Investor Day

On Sept. 16, 2019, TransAlta held the 2019 Investor Day where the Clean Energy Investment Plan was announced. See further details in the Strategic Growth and Corporate Transformation section of this MD&A.

In addition, the Corporation announced that it has adopted, based on TransAlta level deconsolidated cash flows, a deconsolidated Debt/EBITDA target of 2.5 to 3.0 times, and a dividend policy of returning between 10 and 15 per cent of TransAlta deconsolidated Funds from Operations to common shareholders. The credit metrics and dividend policy are being presented on a deconsolidated basis, allowing investors to understand how the dividends received from TransAlta Renewables and TA Cogen are either being returned or invested for TransAlta shareholders. See the Key Financial Ratios section of this MD&A for further details.

Termination of the Alberta Sundance Power Purchase Arrangements with the Balancing Pool

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective March 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective March 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full amount it was seeking to recover, being $56 million, plus GST and interest.

TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed the transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility. As a result, TransAlta owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The Keephills 3 facility is a 463 MW coal-fired generating facility located approximately 70 kilometers west of Edmonton, Alberta, adjacent to TransAlta's existing Keephills Unit 1 and Unit 2 power plants. The Keephills 3 facility achieved commercial operation in 2011, and has been identified as a candidate for TransAlta's intended coal-to-gas conversions.

The purchase prices for each non-operating interest largely offset each other, resulting in a payment of $10 million from Capital Power to TransAlta, subject to working capital settlements. Final working capital true-ups and settlements will occur within 90 days of the closing date.

The Corporation has early-adopted amendments to IFRS 3 Business Combinations, which introduce an optional fair value concentration test, that the Corporation elected to apply to its acquisition of the non-operating interest in Keephills 3. As a result, on the transaction closing of Oct. 1, 2019, the acquisition has been accounted for as an asset acquisition with the $301 million purchase price allocated as follows: working capital $11 million, property, plant and equipment $308 million, other assets $3 million, other liabilities $2 million and decommissioning and other provisions $19 million.

As at Sept. 30, 2019, the Corporation has re-classified the assets and liabilities related to the Genesee 3 disposal group, which are primarily comprised of working capital, property, plant and equipment, intangible assets, and decommissioning and other provisions, as held for sale on the statement of financial position.

Management Changes

On Aug. 8, 2019, the Board of Directors appointed John Kousinioris to Chief Operating Officer of TransAlta Corporation. Mr. Kousinioris previously held the roles of Chief Legal Officer and most recently Chief Growth Officer at TransAlta. Prior to this promotion, he was responsible for overseeing the areas of business development, gas and renewables operations, commercial, and energy marketing.

On May 17, 2019, the Corporation announced the promotion of Todd Stack to CFO. Mr. Stack, who has served as Managing Director and Corporate Controller of the Corporation since February 2017, has been responsible for providing leadership and direction over TransAlta's financial activities, corporate accounting, reporting, tax, and planning.

Since joining TransAlta in 1990, Mr. Stack has acted as the Corporation's Treasurer, Corporate Controller, as well as a member of the corporate development team reviewing greenfield and acquisition opportunities. Prior to joining the finance team at TransAlta, Mr. Stack held a number of roles in the engineering team, including design, operations and project management.

Strategic Investment by Brookfield

On March 25, 2019, the Corporation announced it had entered into an agreement whereby Brookfield will invest $750 million in the Corporation ("Investment Agreement"). This investment provides the financial flexibility to drive TransAlta's transition to 100% clean energy by 2025, recognizes the anticipated future value of TransAlta's Alberta Hydro Assets, and accelerates the Corporation's plan to return capital to its shareholders.

Under the terms of the agreement, Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for 7% unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions precedent.

Upon entering into the Investment Agreement and as required in the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was paid upon completion of the initial funding. These transaction costs have been recognized as part of the carrying value of the debentures.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than 9% at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share. TransAlta shareholders elected two experienced Brookfield directors, Harry Goldgut and Richard Legault, to our Board of Directors at the 2019 Annual and Special Meeting of shareholders. TransAlta and Brookfield intend to work together to complete TransAlta's transition to clean energy, maximize the value of the Alberta Hydro Assets, and create long-term shareholder value.

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within the next three years.

Normal Course Issuer Bid

On May 27, 2019 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 29, 2019, and ends on May 28, 2020, 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.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the nine months ended Sept. 30, 2019, the Corporation purchased and cancelled 3,133,200 common shares at an average price of $8.57 per common share, for a total cost of $27 million. See Note 15 of the unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2019 for further details.

Mothballing of Sundance Units

On March 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020. The extensions were requested by TransAlta based on TransAlta's assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

Acquisition of Two US Wind Projects

During the third quarter of 2019, subsidiaries of TransAlta entered into final agreements with an external party for a planned tax equity investment in the Big Level and Antrim wind projects. The total financing is expected to be approximately US$125 million to US$135 million, with initial funding of approximately US$35 million and US$90 million, respectively, coinciding with Antrim and Big Level each achieving commercial operation, subject to customary conditions. The tax equity financing will be classified as long-term debt on the statement of financial position.

During the first nine months of 2019, TransAlta Renewables funded $93 million (US$69 million) of construction costs for the US Wind Projects. On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the Corporation acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, we recognized $50 million for assets under construction in property, plant and equipment and $15 million in intangibles. The Corporation also paid the final holdback for the Big Level development project of $7 million (US $5 million) due on the closing of Antrim. Upon the closing of the purchase of Antrim, TransAlta Renewables funded an additional $70 million (US$52 million) by subscribing for an interest-bearing promissory note issued by the project entity.

Refer to the Strategic Growth and Corporate Transformation section of this MD&A for updates on ongoing projects. Refer to Note 4 of the audited annual 2018 consolidated financial statements within our 2018 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2019 for significant events impacting both prior and current year results.

Regulatory Updates

Refer to the Regional Regulation and Compliance discussion in our 2018 annual MD&A for further details that supplement the recent developments as discussed below:

Canadian Federal Government

Large Greenhouse Gas Emitter Regulations

On June 21, 2018, *the Greenhouse Gas Pollution Pricing Act (GGPPA)* was passed. Under this Act, the Canadian federal government implemented a national price on GHG emissions. The price began at $20 per tonne of carbon dioxide equivalent (CO_2e) emitted in 2019 and will rise by $10 per year until reaching $50 per tonne in 2022.

Carbon Tax

On Jan. 1, 2019, the GGPPA's "backstop" mechanisms came into effect for large emitters in jurisdictions that did not implement an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system - Ontario, Manitoba, New Brunswick, Saskatchewan, Prince Edward Island, Yukon and Nunavut.

The backstop mechanism has two components: a carbon levy for small emitters and regulation for large emitters called the Output Based Pricing Standard (OBPS). The carbon levy sets a carbon price per tonne of greenhouse gas emissions related to transportation fuels, heating fuels and other, small emission sources. The OBPS is an intensity-based standard where large emitters must meet an industry specific emission intensity performance standard per unit of production. If the facility's emission intensity is below or above the performance standard, the facility will generate carbon credits or carbon obligations equal to the difference between the industry's emission intensity performance standard and the regulated facility's emission intensity.

The final regulations for the OBPS were released on June 28, 2019. TransAlta currently operates under this system in Ontario.

Clean Fuel Standard

In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard ("CFS") to reduce Canada's greenhouse gas emissions through the increased use of lower carbon fuels, energy sources and technologies. The objective of the regulation is to achieve 30 million metric tonnes of annual reductions in GHG emissions by 2030. The CFS will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. Under the proposed policy, coal combusted at facilities that are covered by coal-fired electricity regulations will be exempt from the regulation. Natural gas used for electricity production is currently expected to be included under the gaseous stream.

Consultation on the gaseous stream, commenced in 2019 and will continue into 2020. Publication of the draft regulations for the gaseous stream will occur in late 2020 with final regulations expected in 2021. The gaseous stream is currently expected to come into force by 2023. TransAlta continues to be engaged in the consultation process.

Alberta

Large Greenhouse Gas Emitter Regulations

On Jan. 1, 2018, the Alberta government transitioned from the *Specified Gas Emitters Regulation* to the *Carbon Competitiveness Incentive Regulation* ("CCIR"). Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sectoral performance compliance standard.

On April 16, 2019, the United Conservative Party ("UCP") won the Alberta provincial election with a majority government. The UCP have committed to moving away from the CCIR to a new regulation called the Technology Innovative Emissions Reduction ("TIER") regime, expected to take effect on Jan. 1, 2020.

Under the proposed TIER regulations, large emitters that emit over 100,000 tCO_2e per year will be covered with an opt-in provision from 100,000 to 10,000 tCO_2e per year. For the electricity sector, like CCIR, TIER is an intensity-based carbon standard where emission obligations are assessed on a tonnes of carbon per MWh. Electricity sector covered entities will have to meet a "good-as-best-gas" sector intensity standard that is proposed to be the same as CCIR at 370 tCO_2e/GWh. All other larger emitters will need to reduce emission by 10% from their 2016-18 average facility emission factor.

Facilities with emissions above the set reduction requirements will need to comply with TIER by: 1) paying the Carbon Fund price, 2) making reductions at their facility, 3) remitting emission performance credits from other facilities, or 4) remitting emission offset credits.

To get stakeholder feedback on TIER, the Alberta government held consultation meetings throughout July ending with final written submissions due on Aug. 2, 2019. The Alberta government intends to draft and pass the new TIER regulation during the Fall session with TIER replacing CCIR on Jan. 1, 2020.

Upon finalization of the program, the TIER system will be submitted for review by the federal government. The federal government conducts an annual review of provincial carbon pricing systems to confirm alignment with the guidance requirements. The 2019 review process is expected to be completed in the fourth quarter of 2019.

Carbon Tax
The Albertan UCP government passed *Bill 1: An Act to Repeal the Carbon Tax* that removed the carbon tax as of May 30, 2019 on fossil fuel sources such as gasoline, natural gas, etc. The federal government has committed to replace the provincial carbon tax with an equivalent federal carbon tax as of January 1, 2020. TransAlta will not pay the carbon tax on the relevant fuels from June 1, 2019 to December 31, 2019.

Electricity Market Review
On July 24, 2019, the UCP cancelled the capacity market after completing their 90 day review process. The Alberta government proposed Bill 18 *Electricity Statutes (Capacity Market Termination) Amendment Act* ("Bill 18") in the legislature which unwinds the changes that were made to the statutory scheme by the previous government to implement a capacity market design. Bill 18 passed first reading on Oct. 17, 2019. Maintaining the existing energy-only structure as contemplated in Bill 18 is supportive of TransAlta's current and future strategies.

Ontario
Large Greenhouse Gas Emitter Regulations
Ontario large emitters are currently subject to the federal backstop OBPS regulation and are expected to remain under this regulation until at least the next federal review in 2022.

On July 4, 2019, the Government of Ontario released the final regulations for the provincial Greenhouse Gas Emissions performance Standards (EPS). The EPS establishes greenhouse gas emission limits on covered facilities. Large emitters generating over 50,000 tonnes CO_2e or more per year will be covered with an opt-in provision for those emitters between 10,000 and 50,000 tCO_2e annually. The carbon emissions limit for electricity is set at 420 tCO_2e/GWh. The program also provides a method that accounts for the carbon efficiency of cogeneration units.

Facilities with emissions above the set reduction requirements can comply by: 1) buying excess emission units from the regulator, 2) making reductions at their facility, or 3) using emission performance units generated by facilities emitting below their emission intensity limit.

The first compliance period under the Regulation will begin on Jan. 1 in the year in which Ontario is removed from the list of provinces to which the federal OBPS applies. We currently anticipate this to occur on January 1, 2023.

Carbon Tax
The Federal carbon tax was implemented in Ontario as of April 1, 2019. It is expected to remain in place until the next Federal review in 2022.

Electricity Market Review
Ontario is implementing a transitional capacity market that will allow demand response and existing, uncontracted generators to participate. The first auction will be held in December 2019 for the 2020 obligation period. TransAlta assets are contracted and will not participate. This capacity market will evolve and allow participation by imports and uncontracted capacity at contracted facilities. TransAlta may be able to participate in the 2022 or later auctions.

Ontario is planning to implement major changes to its energy market, including the adoption of nodal pricing (transmission congestion pricing) and a day-ahead market. These changes are expected to have small impacts on prices in Southern Ontario where most of TransAlta's assets are located.

Capital Structure and Liquidity

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

As at	Sept. 30, 2019 $	Sept. 30, 2019 %	Dec. 31, 2018 $	Dec. 31, 2018 %
TransAlta Corporation				
Recourse debt - CAD debentures	**647**	**9**	647	9
Recourse debt - US senior notes	**917**	**13**	943	13
Exchangeable securities	**325**	**5**	—	—
US tax equity financing	**24**	**—**	28	—
Credit facilities	**1**	**—**	174	2
Other	**9**	**—**	11	—
Less: Cash and cash equivalents	**(308)**	**(4)**	(16)	—
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	**—**	(27)	—
Less: fair value asset of economic hedging instruments on debt	**(9)**	**—**	(10)	—
Net recourse debt	**1,596**	**23**	1,750	24
Non-recourse debt	**428**	**6**	469	6
Lease obligations	**53**	**1**	63	1
Total net debt - TransAlta Corporation	**2,077**	**30**	2,282	31
TransAlta Renewables				
Credit facility	**159**	**2**	165	2
Less: cash and cash equivalents	**(18)**	**—**	(73)	(1)
Net recourse debt	**141**	**2**	92	1
Non-recourse debt	**740**	**11**	767	11
Lease obligations	**17**	**—**	—	—
Total net debt - TransAlta Renewables	**898**	**13**	859	12
Total consolidated net debt	**2,975**	**43**	3,141	43
Non-controlling interests	**1,101**	**16**	1,137	16
Equity attributable to shareholders				
Common shares	**3,026**	**43**	3,059	42
Preferred shares	**942**	**13**	942	13
Contributed surplus, deficit, and accumulated other comprehensive income	**(1,063)**	**(15)**	(1,004)	(14)
Total capital	**6,981**	**100**	7,275	100

Overall, our total consolidated net debt decreased by $166 million during the first nine months of 2019, mainly due to lower drawings on the credit facilities, increased cash and cash equivalents and scheduled debt payments, partially offset by the issuance of the exchangeable securities. Between 2019 and 2021, we have approximately $601 million of debt maturing. We will receive the proceeds from the issuance to Brookfield of the second tranche of exchangeable securities of $400 million in the fourth quarter of 2020. See the Significant and Subsequent Events section for further details.

Our credit facilities provide us with significant liquidity. We have a total of $2.2 billion (Dec. 31, 2018 - $2.0 billion) of committed credit facilities, comprised of our $1.25 billion (Dec. 31, 2018 - $1.25 billion) committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $0.7 billion (Dec. 31, 2018 - $0.5 billion) and our $0.2 billion (Dec. 31, 2018 - $0.2 billion) committed bilateral facilities. These facilities were renewed, and TransAlta Renewables' facility was increased by $200 million, during the second quarter of 2019 and expire in 2023, 2023, and 2021 respectively. The $1.95 billion (Dec. 31, 2018 - $1.75 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. In total, $1.4 billion (Dec. 31, 2018 - $0.9 billion) is not drawn. At Sept. 30, 2019, the $0.8 billion (Dec. 31, 2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $160 million (Dec. 31, 2018 - $339 million) and letters of credit of $661 million (Dec. 31, 2018 - $720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, the Corporation also has $326 million of available cash and cash equivalents.

The Corporation's subsidiaries have issued non-recourse bonds of $1,167 million (Dec. 31, 2018 - $1,235 million) that are subject to customary financing conditions and covenants that may restrict our ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2019. At Sept. 30, 2019, $27 million (Dec. 31, 2018 -$33 million) of cash was subject to these financial restrictions.

We have nil (Dec. 31, 2018 - $31 million) restricted cash related to the Kent Hills project financing. We have $17 million (Dec. 31, 2018 - $35 million) of restricted cash related to the TransAlta OCP bonds. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. We have elected to use letters of credit as at Sept. 30, 2019.

The weakening of the US dollar has decreased our long-term debt balances by $28 million in 2019. 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:

	Sept. 30, 2019
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 on US operations	**(6)**
Unhedged	**(2)**
Total	**(28)**

Share Capital

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

As at	November 6,	Sept. 30, 2019	Dec 31, 2018
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**281.6**	**281.6**	284.6
Preferred shares			
Series A	**10.2**	10.2	10.2
Series B	**1.8**	1.8	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, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests

As of Sept. 30, 2019, we own 60.5 cent per cent (Sept. 30, 2018 - 61.0 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables Dividend Reinvestment Plan. We do not participate in this plan.

We also own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural-gas-fired facilities (Mississauga, Ottawa, Windsor and Fort Saskatchewan) and one coal-fired generating facility.

Reported earnings attributable to non-controlling interests for the year-to-date and third quarter 2019 increased to $67 million and $16 million, respectively, from $65 million and $9 million, respectively, in the same periods of 2018. Earnings from TransAlta Renewables for the three and nine months ended Sept. 30, 2019 increased due to an increase in the fair value of investments in subsidiaries of TransAlta, partially offset by a decrease in finance and interest income related to subsidiaries of TransAlta and higher depreciation expense as a result of changes in useful lives. Earnings from TA Cogen increased in both the quarter and the year-to-date 2019 periods, mainly due to strong Alberta pricing and lower costs of fuel at the coal-fired generating facility.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Interest on debt	**40**	44	**123**	142
Interest on exchangeable securities	**7**	—	**12**	—
Interest income	**(4)**	(2)	**(9)**	(8)
Capitalized interest	**(2)**	(1)	**(4)**	(1)
Loss on early redemption of US Senior Notes and Debentures	**—**	19	**—**	24
Interest on lease obligations	**1**	—	**3**	2
Credit facility and bank charges	**4**	4	**11**	10
Other interest and fees(1)	**3**	3	**7**	13
Accretion of provisions	**6**	6	**18**	18
Net interest expense	**55**	73	**161**	200

(1) During the nine months ended Sept. 30, 2018, approximately $5 million of costs were expensed due to project level financings that was no longer practicable.

Interest expense decreased during the three and nine months ended Sept. 30, 2019 due to lower debt levels, the $19 million pre-payment premium relating to the early redemption of the $400 million debenture in the third quarter of 2018, the $5 million pre-payment premium incurred in the first quarter of 2018 relating to the early redemption of the US$500 million Senior Notes and the $5 million of costs expensed in 2018 in connection with project level financing that was no longer practicable. Interest on the exchangeable securities was largely offset by lower interest on debt.

Dividends to Shareholders

The following are the common and preferred shares dividends declared from Jan. 1, 2019 up to Nov 6, 2019:

	Payable date		Common dividends	Preferred Series dividends per share				
Declaration date	**Common Shares**	**Preferred Shares**	**per share**	**A**	**B**	**C**	**E**	**G**
Oct. 9, 2019	Jan. 1, 2020	Dec. 31, 2019	0.04	0.16931	0.23113	0.25169	0.32463	0.31175
July 16, 2019	Oct. 1, 2019	Sept. 30, 2019	0.04	0.16931	0.23422	0.25169	0.32463	0.33125
April 15, 2019	July 1, 2019	June 30, 2019	0.04	0.16931	0.23136	0.25169	0.32463	0.33125

Financial Position

The following table outlines significant changes in the Condensed Consolidated Statements of Financial Position as at Sept. 30, 2019, compared to Dec. 31, 2018:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	237	Timing of receipts and payments and cash received from the issuance of the exchangeable securities
Trade and other receivables	(304)	Timing of customer receipts and seasonality of revenues
Restricted cash	(49)	Kent Hills restricted cash was released in July 2019 ($31 million) and the restricted cash related to the OCP bonds was paid in Feb. 2019 ($35 million), partially offset by OCA payments received ($17 million) in August 2019 that will be restricted until the OCP bonds are paid in Feb. 2020
Assets held for sale	266	The Genesee 3 assets that were sold to Capital Power on Oct. 1, 2019 (see the Significant and Subsequent Events section of this MD&A for further details)
Property, plant, and equipment, net	(259)	Depreciation for the period ($464 million), transfers to assets held for sale ($219 million), adjustments on implementing IFRS 16 ($62 million), unfavourable change in foreign exchange rates ($55 million) and retirement of assets and disposals ($34 million), partially offset by additions ($340 million), impairment reversal ($149 million), acquisition relating to Antrim ($50 million) and revisions to decommissioning and restoration costs ($36 million)
Right of use assets, net	74	Transfers from property, plant and equipment, intangible assets and other assets ($38 million) and new right of use assets recognized under IFRS 16 ($47 million) (see Accounting Changes section for further details), partially offset by depreciation ($13 million)
Intangible assets	(48)	Amortization ($37 million) and transfers to assets held for sale ($28 million), partially offset by the acquisition relating to Antrim ($14 million) and additions ($10 million)
Risk management assets (current and long term)	(28)	Contract settlements and unfavourable foreign exchange rates, partially offset by favourable market prices
Other assets	(44)	Note receivable for the project development costs related to the Pioneer Pipeline moved to PP&E additions ($17 million), write-off of project development costs for projects that will not be moving ahead ($18 million) and scheduled reduction in the South Hedland prepaid transmission access and distribution costs ($8 million)
Others	(12)	
Total decrease in assets	**(167)**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(139)	Timing of payments and accruals
Dividends payable	(21)	Timing of the declaration of common and preferred share dividends
Liabilities held for sale	32	The Genesee 3 liabilities that were sold to Capital Power on Oct. 1, 2019 (see the Significant and Subsequent Events section of this MD&A for further details)
Credit facilities, long term debt, and lease obligations (including current portion)	(272)	Repayments on the credit facilities ($179 million), repayments of long-term debt ($71 million) and favourable changes in foreign exchange ($28 million) were partially offset by and an increase in lease obligations on implementation of IFRS 16, net of repayments ($7 million)
Exchangeable securities	325	Issuance of the exchangeable securities (see Significant and Subsequent Events section for further details)
Decommissioning and other provisions (current and long term)	103	Change in estimate for the Centralia mine ($109 million). See the Accounting Changes section of this MD&A for further details
Contract liabilities (current and long term)	16	Contract liabilities moved from defined benefit obligation and other long term liabilities as they are no longer considered leases on the adoption of IFRS 16 (see the Accounting Changes section for further details)
Defined benefit obligation and other long term liabilities	28	Actuarial losses ($44 million) partially offset by liabilities moved to contract liabilities ($16 million)
Deferred income tax liabilities	(69)	Decrease in taxable temporary differences mainly due to the Alberta tax rate reduction (see the Other Consolidated Analysis section for further details)
Risk management liabilities (current and long term)	(51)	Contract settlements and unfavourable foreign exchange rates, partially offset by favourable market prices
Equity attributable to shareholders	(92)	Net earnings ($6 million) and the effects of share-based payment plans ($13 million), partially offset by other comprehensive loss ($48 million), shares purchased under the NCIB ($27 million) and common and preferred share dividends declared ($43 million)
Non-controlling interests	(36)	Distributions paid and payable ($106 million) and intercompany FVOCI investments ($14 million), partially offset by net earnings ($67 million) and changes in non-controlling interests in TransAlta Renewables from dividend reinvestment plan ($17 million)
Others	9	
Total decrease in liabilities and equity	**(167)**	

Cash Flows

The following tables outline significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2019, compared to the three and nine months ended Sept. 30, 2018:

3 months ended Sept. 30	2019	2018	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**208**	123	85	
Provided by (used in):				
Operating activities	**328**	159	169	Favourable changes in non-cash working capital ($121 million) were partially offset by lower cash flow from operations before changes in working capital ($48 million)
Investing activities	**(91)**	(135)	44	Decreased restricted cash ($49 million) and a favourable change in non-cash investing working capital ($16 million), partially offset by lower receipts from finance leases ($8 million), higher distributions paid through the specified loan receivable ($7 million) and additions ($ 3 million)
Financing activities	**(119)**	(51)	(68)	Lower debt issuances ($345 million) and repayments on the credit facilities ($167 million), partially offset by lower repayments of long-term debt ($395 million), lower financings fees paid ($23 million), lower distributions paid to subsidiaries' non-controlling interests ($13 million), and a favourable change in non-cash financing working capital ($12 million).
Translation of foreign currency cash	**—**	(1)	1	
Cash and cash equivalents, end of period	**326**	**95**	**231**	

9 months ended Sept. 30	2019	2018	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**89**	314	(225)	
Provided by (used in):				
Operating activities	**668**	688	(20)	Lower cash flow from operations before changes in working capital ($117 million) mainly due to the 2018 one time receipt of $157 million for the termination of the Sundance Units B and C PPAs. This was partially offset by a favourable change in non-cash working capital ($97 million)
Investing activities	**(321)**	(294)	(27)	Investment in the Pioneer Pipeline ($83 million), higher additions to PP&E ($64 million) and lower receipts from finance leases ($25 million), partially offset by the decrease in restricted cash ($84 million), a favourable change in non-cash investing working capital balances ($60 million), lower additions to intangibles ($6 million) and cash proceeds received from an insurance claim for the fire at Summerview ($4 million)
Financing activities	**(109)**	(613)	504	Lower repayments of long-term debt ($1,066 million), issuance of the exchangeable securities ($350 million) and lower distributions paid to subsidiaries' non-controlling interests ($38 million), partially offset by higher net repayments under credit facilities ($410 million), lower debt issuances ($345 million), lower proceeds on issuance of TransAlta Renewables common shares ($144 million), lower realized gains on financial instruments ($48 million) and higher share buybacks under NCIB ($13 million)
Translation of foreign currency cash	**(1)**	—	(1)	
Cash and cash equivalents, end of period	**326**	**95**	**231**	

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each cash generating unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

I. 2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the CGU exceeded the carrying value by a substantial margin, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period included cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	2016
Mid-Columbia annual average power prices	US$30.37 to US$41.94 per MWh	US$22.00 to US$46.00 per MWh
On-highway diesel fuel on coal shipments	US$2.35 to US$2.40 per gallon	US$1.69 to US$2.09 per gallon
Discount rates	5.2 to 6.4 per cent	5.4 to 5.7 per cent

Refer to the Accounting Changes section for details on the $109 million expense related to the Centralia mine decommissioning and restoration provision.

II. 2018

Sundance Unit 2

In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on July 31, 2018. Discounting did not have a material impact.

Lakeswind and Kent Breeze

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 3K). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (See Note 11).

III. Project Development Costs

During the three and nine months ended Sept. 30, 2019, the Corporation wrote off $18 million in project development costs related to projects that are no longer proceeding.

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements, or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities, or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Guarantee Contracts

We have 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, construction projects, and purchase obligations. At Sept. 30, 2019, we provided letters of credit totaling $661 million (Dec. 31, 2018 - $720 million) and cash collateral of $31 million (Dec. 31, 2018 - $105 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Income Taxes

In the second quarter of 2019, the Corporation recognized a deferred income tax recovery of $40 million related to a decrease in the Alberta corporate tax rate from 12 per cent to 8 per cent. The lower tax rates will be phased in as follows: 11 per cent effective July 1, 2019; 10 per cent effective Jan. 1, 2020; 9 per cent effective Jan. 1, 2021; and 8 per cent effective Jan. 1, 2022.

Commitments

During the second quarter of 2019, the Corporation entered into new contractual commitments for new assets beginning in the third quarter of 2019, with total payments of $61 million. Annual payments will be: 2019 - $5 million; 2020 - $17 million; 2023 to 2038 - $2-3 million per year. In October 2019, TransAlta entered into an additional commitment to transport 150,000 GJ/day of natural gas on a firm basis for a 15 year period, beginning in 2023.

In addition, beginning on Nov. 1, 2019, TransAlta has a commitment to transport the initial daily contract quantity of 139,000 GJ/day of natural gas on a firm basis on the Pioneer Pipeline.

For other Growth project commitments, refer to the Strategic Growth and Corporate Transformation and Significant and Subsequent Events sections for details.

Contingencies

I. Line Loss Rule Proceeding

The Corporation has been participating in a 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 Alberta Electric System Operator to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total potential retroactive exposure faced by the Corporation for its non-PPA MWs. The Corporation has recorded a provision of $15 million as at Sept. 30, 2019 (Dec. 31, 2018 - $15 million), which is expected to be reduced to $10 million upon the closing of the Keephills 3 and Genesee 3 asset swap on Oct. 1, 2019.

II. FMG Disputes

The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment 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 second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

III. Mangrove

On April 23, 2019, Mangrove Partners 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 Partners is seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations.

IV. Coalview Fatality - Regulatory Investigation

On Sept. 4, 2019, the United States Mine Safety and Health Administration ("MSHA") released its report following its investigation into the death of an employee of Coalview Centralia, LLC ("Coalview"). MSHA cited Coalview, as mine contractor, for two violations, finding that there was an "unwarrantable failure to comply with a mandatory standard". TransAlta, however, was also cited with a single violation - failing to maintain machinery and equipment in safe operating condition despite the fact that TransAlta did not own, operate or maintain the equipment. TransAlta is taking steps to contest the citation.

V. Keephills Force Majeure

Keephills Unit 1 was taken offline Mar. 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, the PPA Buyer at the time, did not dispute the force majeure but the Balancing Pool purported to do so. TransAlta denied that the Balancing Pool had the right to do so. Ultimately, the Balancing Pool brought and won an Originating Application confirming it has a right under the PPA to commence an arbitration, independent of the PPA Buyer. On Sept. 4, 2019 the Alberta Court of Appeal upheld the lower court's decision. The Balancing Pool is seeking to recover $12 million in capacity payment charges it paid TransAlta resulting from the force majeure declaration. The dispute can now proceed to arbitration, but a schedule has not been set.

Financial Instruments

Refer to Note 14 of the notes to the audited annual consolidated financial statements within our 2018 Annual Integrated Report and Note 9 and 14 of our unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2019 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2018 Annual Integrated Report and Note 10 of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2018.

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 financial statements.

As at Sept. 30, 2019, total Level III financial instruments had a net asset carrying value of $676 million (Dec. 31, 2018 - $695 million net asset). The decrease during the period is primarily attributable to contract settlements and unfavourable change in foreign exchange rates, partially offset by favourable market prices during the period.

2019 Financial Outlook

During the first nine months of the year, we have experienced stronger than anticipated results from our Canadian Coal segment. This is due to the combined impact of higher realized prices, lower fuel, carbon compliance and purchased power costs as the Pioneer Pipeline transported first gas four months ahead of schedule, as well as, lower OM&A costs. Year-to-date results combined with our forecast provide us with the confidence to revise our FCF outlook. The following table outlines our expectation on key financial targets for 2019:

Measure	Target	Revised Target
Comparable EBITDA	$875 million to $975 million	No Change
FCF	$270 million to $330 million	$300 million to $340 million
Dividend	$0.16 per share annualized	

Range of Key Assumptions

Market	Power Prices ($/MWh)
Alberta Spot	$50 to $60
Alberta Contracted	$50 to $55
Mid-C Spot (US$)	$20 to $25
Mid-C Contracted (US$)	$47 to $53

Other assumptions relevant to 2019 financial outlook	
Sustaining capital	$140 million to $165 million (revised)(1)
Productivity capital	$10 million to $15 million
Sundance coal capacity factor	30%
Hydro/ Wind resource	Long term average

(1) The original 2019 outlook for sustaining capital spend included an additional $20 million to $25 million in expected spend on finance leases. On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.

Operations

Availability

Availability of our Canadian coal fleet is expected to be in the range of 87 to 90 per cent in 2019. Availability of our other generating assets (gas, renewables) is expected to be in the range of 90 to 96 per cent in 2019. We will be accelerating our transition to gas and renewables generation, and continue on our coal-to-gas conversion strategy as set out in the Strategic Growth and Corporate Transformation section of this MD&A.

Market Pricing and Hedging Strategy

For 2019, power prices in Alberta are expected to be slightly higher than 2018 due to a full year with improved supply demand balances and strong settled prices year-to-date. Pacific Northwest power prices for 2019 are expected to be higher than 2018 as prices for the first half of the year were stronger relative to 2018. Prices in the fourth quarter of 2019 will be dependent on weather and any potential constraints on the natural gas supply between British Columbia and the region. Ontario power prices are expected to be lower than 2018 given weaker prices since the second quarter, which is expected to extend into the fourth quarter of 2019.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF which also provides for positive exposure to price volatility in Alberta. Given our cash operating costs, we can be more or less hedged in a given period, and we expect to realize our annual FCF targets through a combination of forward hedging and selling generation into the spot market.

Fuel Costs

In Alberta, we expect our cash fuel costs per tonne of coal to remain consistent with 2018 costs, even though we expect to mine approximately 2 - 3 million tonnes less in 2019. Total fuel costs on a dollar per MWh basis are expected to remain consistent with 2018 while total fuel costs are expected to be slightly lower due to increased co-firing with natural gas among the merchant units.

In the Pacific Northwest, our US Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at US Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost for the remainder of 2019 is expected to increase by approximately 1 per cent compared to costs incurred in 2018 mainly due to higher natural gas prices.

Aside from the gas used for co-firing at the Canadian Coal plants, most of our other generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Energy Marketing
Comparable 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 2019, expectation for Energy Marketing is for the segment to contribute between $100 million to $120 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies
Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense
Net interest expense for 2019 is expected to be lower than in 2018 largely due to lower interest rates on long-term debt and no prepayment premiums incurred. However, changes in interest rates and in the value of the Canadian dollar relative to the US dollar can affect the amount of net interest expense incurred. In addition, interest expense will increase as a result of implementing IFRS 16. See the Accounting Changes section of this MD&A for further details.

Liquidity and Capital Resources
We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to approximately $1.4 billion under our committed facilities and $326 million in cash and cash equivalents. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in 2020 and 2022 with cash flow from operations, the proceeds received from the exchangeable securities and our existing credit facilities.

Growth and Coal-to-Gas Conversion Expenditures

Our growth projects are focused on sustaining our current operations and supporting our growth strategy in our renewables platform. A summary of the significant growth and major projects that are in progress is outlined below:

	Total project			Remaining estimated spend in 2019	Target completion date	Details
	Estimated spend		Spent to date[1]			
Project						
Big Level wind development project[2]	225 -	240	145	86	Q4 2019	90 MW wind project with a 15-year PPA
Antrim wind development project[3]	100 -	110	87	18	Q4 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	95 -	100	98	—	Q4 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Skookumchuck wind development project	150 -	160	—	—	Q1 2020	Option to purchase a 49 per cent ownership in the 136.8 MW wind project with a 20-year PPA
Windrise wind development project	270 -	285	47	4	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery	7 -	8	—	—	Q2 2020	10 MW / 20 MWh utility-scale storage project
Boiler conversions	100 -	200	16	16	2020 to 2022	Coal-to-gas conversions at Canadian Coal
Repowering	750 -	770	—	—	2023	Repower the steam turbines at Sundance Unit 5
Kaybob cogeneration project	105 -	115	6	17	Q4 2021	40 MW cogeneration project with SemCAMS under a 13-year fixed price contract
Total	**1,802 -**	**1,988**	**399**	**141**		

(1) Represents amounts spent as of Sept. 30, 2019.
(2) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is US$173 million to US$185 million, spent to date is US$109 million and estimated remaining spend in 2019 is US$69 million. TransAlta Renewables will fund the construction costs using its existing liquidity and tax equity.
(3) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is US$77 million to US$85 million, spent to date is US$66 million and estimated remaining spend in 2019 is US$15 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.

Sustaining and Productivity Capital Expenditures

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

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

Category	Description	Spent to date[1]	Expected spend in 2019
Routine capital	Capital required to maintain our existing generating capacity	**33**	50 — 60
Planned major maintenance	Regularly scheduled major maintenance	**60**	70 — 80
Mine capital	Capital related to mining equipment and land purchases	**18**	20 — 25
Total sustaining capital[2]		**111**	**140 — 165**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**7**	10 — 15
Total sustaining and productivity capital		**118**	**150 — 180**

(1) As at Sept. 30, 2019.
(2) The original 2019 outlook for sustaining capital spend included an additional $20 million to $25 million in expected spend on finance leases. On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.

Significant planned major outages at TransAlta's operated units for the remainder of 2019 include the following:
- distributed planned maintenance expenditures across the entire Hydro fleet; and
- distributed expenditures across our Wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2019:

	Canadian Coal	Gas and Renewables	Total	Lost to date(1)
GWh lost	600 - 625	350 - 375	950 - 1,000	877

(1) As at Sept. 30, 2019.

Funding of Capital Expenditures
Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, the proceeds received from the exchangeable securities and existing liquidity. We have access to approximately $1.7 billion in liquidity. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

Accounting Changes

Current Accounting Changes

I. IFRS 16 *Leases*
The Corporation has adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* (IAS 17) or International Financial Reporting Interpretations Committee Interpretation 4 *Determining whether an arrangement contains a lease*. As a result of the IFRS 16 adoption, the Corporation has changed its accounting policy for leases, which is outlined in Note 2 of the Corporation's unaudited interim condensed consolidated financial statements.

The Corporation has elected to adopt IFRS 16 using the modified retrospective approach on transition. Comparative information has not been restated and is reported under IAS 17. Refer to the Corporation's most recent annual consolidated financial statements for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard of $3 million in Deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and for low value leases;
- Excluding initial direct costs for the measurement of the right of use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;
- Adjusting the right of use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

Impact on the financial statements
Lessee
The Corporation recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. We recognized lease liabilities of $83 million as at Jan. 1, 2019, including $63 million that was previously included as finance lease liabilities.

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of $85 million, including $38 million that was previously included in property, plant and equipment, intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16, resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in Deficit.

Lessor
Several of the Corporation's long term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for applying IFRS 15 *Revenue from Contracts with Customers.* No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

Refer to Note 2 of the Corporation's unaudited interim condensed consolidated financial statements for a more detailed discussion of the Corporation's adoption of IFRS 16.

II. Change in Estimates

Canadian Coal

During the third quarter of 2019, the Corporation adjusted the useful lives of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see the Strategic Growth and Corporate Transformation section for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined cycle conversions. Due to the impact of shortening the lives of the coal assets, overall, depreciation expense for the nine months ended Sept. 30, 2019 increased by approximately $4 million and the full year depreciation expense is expected to increase between $15 million to $17 million, excluding the impact of acquiring the remaining 50 per cent ownership of Keephills 3.

In 2018, as a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(O) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the nine months ended Sept. 30, 2018 increased by approximately $29 million and the 2018 full year depreciation expense increased by approximately $38 million.

Wind and Solar

During the third quarter, the allocation of the costs recognized for the components of the Wind and Solar property, plant and equipment and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. As a result, depreciation expense for the three and nine months ended Sept. 30, 2019 increased by approximately $7 million and the full year depreciation expense is expected to increase by approximately $10 million.

Sheerness

During the second quarter of 2019, the Corporation adjusted the useful life of its Sheerness assets to align with the dual fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the nine months ended Sept. 30, 2019 decreased by approximately $5 million and the full year depreciation expense is expected to decrease by approximately $11 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia

During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that Coalview Centralia, LLC (“Coalview”) will be able to complete the fine coal recovery and reclamation work as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $109 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in immediate recognition for the full $109 million, through asset impairment charges in net earnings.

TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $142 million, which will be incurred between 2021 and 2035. The provision may be revised in compliance with the Corporation's accounting policies, dependent upon future operating decisions and as more information becomes available.

B. Future Accounting Changes

Effective Oct. 1, 2019, the Corporation has early-adopted amendments to IFRS 3 Bu*siness Combinations*, in advance of its mandatory effective date of Jan. 1, 2020. TransAlta adopted the IFRS 3 amendments prospectively and therefore the comparative information presented for 2018 has not been restated. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. Specifically, these amendments:

- clarify the minimum requirements for a business, whereby at minimum, an input and substantive process that together significantly contribute to the ability to create output;
- remove the assessment of whether market participants are capable of replacing any missing elements so that the assessment is on what has been acquired in its current state and condition, rather than on whether market participants are capable of replacing any missing elements, for example, by integrating the acquired activities and assets;
- add guidance to help entities assess whether an acquired process is substantive, which requires more persuasive evidence when there are no outputs because the existence of outputs provides some evidence that the acquired set of activities and assets is a business;
- narrow the definition of outputs to focus on goods or services provided to customers, investment income or other income from ordinary activities; and
- introduce an optional fair value concentration test, that can be applied on a transaction-by-transaction basis, to permit a simplified assessment of whether an acquired set of activities and assets are not a business. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The Corporation elected to apply the optional fair value concentration test to its acquisition of the remaining 50 per cent interest in Keephills 3, see the Significant and Subsequent Events section for further details. There are no other impacts to the asset acquisitions that were completed during the nine months ended Sept. 30, 2019.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually 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 US Coal. 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.

	Q4 2018	Q1 2019	Q2 2019	**Q3 2019**
Revenues	622	648	497	**593**
Comparable EBITDA[1]	261	221	215	**305**
FFO	217	169	155	**244**
Net earnings (loss) attributable to common shareholders	(122)	(65)	—	**51**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.43)	(0.23)	—	**0.18**

	Q4 2017	Q1 2018	Q2 2018	Q3 2018
Revenues	638	588	446	593
Comparable EBITDA[1]	275	393	248	250
FFO	219	318	188	204
Net earnings (loss) attributable to common shareholders	(145)	65	(105)	(86)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.50)	0.23	(0.36)	(0.30)

(1) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.

(2) Basic and diluted earnings per share attributable to common shares are calculated each period using the weighted average number of 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 winter cold 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:

- change in income tax rates in the US in the fourth quarter of 2017 and in Alberta in the second quarter of 2019;
- effects of impairment reversals during the third quarter of 2019 and impairment charges during the second, third and fourth quarters of 2018;
- recognition of the $157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019;
- effects of changes in useful lives of certain assets during the third quarter of 2019 and the second and third quarters of 2017; and
- effects of an impairment of $137 million in the fourth quarter of 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

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''). There have been no material changes in our ICFR or DC&P during the three and nine months ended Sept. 30, 2019, that have 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 are recorded, processed, summarized and reported within the time frame specified in 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 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 report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Sept. 30, 2019, the end of the period covered by this report, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2019**	2018	**2019**	2018
Revenues *(Note 4)*	**593**	593	**1,738**	1,627
Fuel, carbon costs, and purchased power	**257**	308	**800**	764
Gross margin	**336**	285	**938**	863
Operations, maintenance, and administration	**114**	120	**348**	376
Depreciation and amortization	**148**	146	**436**	422
Asset impairment charge (reversal) *(Notes 2 and 5)*	**(22)**	38	**(22)**	50
Taxes, other than income taxes	**8**	7	**23**	23
Termination of Sundance B and C PPAs *(Notes 3D and 17)*	**(56)**	—	**(56)**	(157)
Net other operating income	**(11)**	(16)	**(33)**	(37)
Operating income (loss)	**155**	(10)	**242**	186
Finance lease income	**2**	2	**5**	7
Net interest expense *(Note 6)*	**(55)**	(73)	**(161)**	(200)
Foreign exchange loss	**(9)**	(8)	**(18)**	(15)
Other gains (losses) *(Note 11)*	**(6)**	1	**(18)**	1
Earnings (loss) before income taxes	**87**	(88)	**50**	(21)
Income tax expense (recovery) *(Note 7)*	**10**	(21)	**(23)**	10
Net earnings (loss)	**77**	(67)	**73**	(31)
Net earnings (loss) attributable to:				
TransAlta shareholders	**61**	(76)	**6**	(96)
Non-controlling interests *(Note 8)*	**16**	9	**67**	65
	77	(67)	**73**	(31)
Net earnings (loss) attributable to TransAlta shareholders	**61**	(76)	**6**	(96)
Preferred share dividends *(Note 16)*	**10**	10	**20**	30
Net earnings (loss) attributable to common shareholders	**51**	(86)	**(14)**	(126)
Weighted average number of common shares outstanding in the period *(millions)*	**282**	287	**284**	287
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 15)*	**0.18**	(0.30)	**(0.05)**	(0.44)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)
(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 **2019**	2018	9 months ended Sept. 30 **2019**	2018
Net earnings (loss)	**77**	(67)	**73**	(31)
Other comprehensive income (loss)				
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**—**	10	**(36)**	28
Gains on derivatives designated as cash flow hedges, net of tax(2)	**1**	—	**1**	—
Total items that will not be reclassified subsequently to net earnings	**1**	10	**(35)**	28
Gains (losses) on translating net assets of foreign operations, net of tax	**8**	(29)	**(46)**	31
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(3)	**(6)**	10	**14**	(14)
Gains (losses) on derivatives designated as cash flow hedges, net of tax(4)	**37**	(26)	**32**	2
Reclassification of gains (losses) on derivatives designated as cash flow hedges to net earnings, net of tax(5)	**(19)**	8	**(27)**	(46)
Total items that will be reclassified subsequently to net earnings	**20**	(37)	**(27)**	(27)
Other comprehensive income (loss)	**21**	(27)	**(62)**	1
Total comprehensive income (loss)	**98**	(94)	**11**	(30)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**61**	(101)	**(42)**	(94)
Non-controlling interests *(Note 8)*	**37**	7	**53**	64
	98	(94)	**11**	(30)

(1) Net of income tax recovery of nil and $8 million for the three and nine months ended Sept. 30, 2019 (2018 - $4 million and $10 million expense).
(2) Net of income tax expense of nil and $1 million for the three and nine months ended Sept. 30, 2019 (2018 - nil and nil).
(3) Net of income tax of nil and nil for the three and nine months ended Sept. 30, 2019 (2018 - $1 million and $3 million recovery).
(4) Net of income tax expense of $9 million and $8 million for the three and nine months ended Sept. 30, 2019 (2018 - $6 million recovery and $1 million expense).
(5) Net of reclassification of income tax recovery of $5 million and $7 million for the three and nine months ended Sept. 30, 2019 (2018 - $2 million recovery and $13 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2019**	Dec. 31, 2018
Cash and cash equivalents	**326**	89
Restricted cash *(Note 13)*	**17**	66
Trade and other receivables	**452**	756
Prepaid expenses	**22**	13
Risk management assets *(Notes 9 and 10)*	**160**	146
Inventory	**244**	242
Assets held for sale *(Note 3C)*	**266**	—
	1,487	1,312
Long-term portion of finance lease receivables	**179**	191
Risk management assets *(Notes 9 and 10)*	**620**	662
Property, plant, and equipment *(Note 11)*		
Cost	**13,338**	13,202
Accumulated depreciation	**(7,433)**	(7,038)
	5,905	6,164
Right of use assets *(Note 12)*	**74**	—
Intangible assets	**325**	373
Goodwill	**464**	464
Deferred income tax assets	**17**	28
Other assets	**190**	234
Total assets	**9,261**	9,428
Accounts payable and accrued liabilities	**357**	496
Current portion of decommissioning and other provisions	**47**	70
Risk management liabilities *(Notes 9 and 10)*	**51**	90
Current portion of contract liabilities *(Note 3C)*	**89**	8
Income taxes payable	**19**	10
Dividends payable *(Note 15 and 16)*	**37**	58
Current portion of long-term debt and lease obligations *(Note 13)*	**103**	148
Liabilities held for sale *(Note 3C)*	**32**	—
	735	880
Credit facilities, long-term debt, and lease obligations *(Note 13)*	**2,892**	3,119
Exchangeable securities *(Note 14)*	**325**	—
Decommissioning and other provisions *(Note 2)*	**512**	386
Deferred income tax liabilities	**432**	501
Risk management liabilities *(Notes 9 and 10)*	**29**	41
Contract liabilities	**15**	80
Defined benefit obligation and other long-term liabilities	**315**	287
Equity		
Common shares *(Note 15)*	**3,026**	3,059
Preferred shares *(Note 16)*	**942**	942
Contributed surplus *(Note 15)*	**23**	11
Deficit	**(1,520)**	(1,496)
Accumulated other comprehensive income	**434**	481
Equity attributable to shareholders	**2,905**	2,997
Non-controlling interests *(Note 8)*	**1,101**	1,137
Total equity	**4,006**	4,134
Total liabilities and equity	**9,261**	9,428

Commitments and contingencies *(Note 17)*

Subsequent events *(Note 3)*

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars

Unaudited

9 months ended Sept. 30, 2019	**Common shares**	**Preferred shares**	**Contributed surplus**	**Deficit**	**Accumulated other comprehensive income**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec 31, 2018	**3,059**	**942**	**11**	**(1,496)**	**481**	**2,997**	**1,137**	**4,134**
Impact of changes in accounting policy *(Note 2)*	**—**	**—**	**—**	**3**	**—**	**3**	**—**	**3**
Adjusted balance as at Jan. 1, 2019	**3,059**	**942**	**11**	**(1,493)**	**481**	**3,000**	**1,137**	**4,137**
Net earnings	**—**	**—**	**—**	**6**	**—**	**6**	**67**	**73**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(32)**	**(32)**	**—**	**(32)**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**6**	**6**	**—**	**6**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(36)**	**(36)**	**—**	**(36)**
Intercompany fair value through OCI investments	**—**	**—**	**—**	**—**	**14**	**14**	**(14)**	**—**
Total comprehensive income (loss)	—	—	—	**6**	**(48)**	**(42)**	**53**	**11**
Common share dividends	**—**	**—**	**—**	**(23)**	**—**	**(23)**	**—**	**(23)**
Preferred share dividends	**—**	**—**	**—**	**(20)**	**—**	**(20)**	**—**	**(20)**
Shares purchased under NCIB *(Note 15)*	**(34)**	**—**	**—**	**7**	**—**	**(27)**	**—**	**(27)**
Changes in non-controlling interests in TransAlta Renewables *(Note 8)*	**—**	**—**	**—**	**3**	**1**	**4**	**17**	**21**
Effect of share-based payment plans *(Note 15)*	**1**	**—**	**12**	**—**	**—**	**13**	**—**	**13**
Distributions paid, and payable, to non-controlling interests *(Note 8)*	**—**	**—**	**—**	**—**	**—**	**—**	**(106)**	**(106)**
Balance, Sept. 30, 2019	**3,026**	**942**	**23**	**(1,520)**	**434**	**2,905**	**1,101**	**4,006**

9 months ended Sept. 30, 2018	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec 31, 2017	3,094	942	10	(1,209)	489	3,326	1,059	4,385
Impact of changes in accounting policy	—	—	—	(14)	—	(14)	1	(13)
Adjusted balance as at Jan. 1, 2018	3,094	942	10	(1,223)	489	3,312	1,060	4,372
Net earnings (loss)	—	—	—	(96)	—	(96)	65	(31)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	17	17	—	17
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(44)	(44)	—	(44)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	28	28	—	28
Intercompany fair value through OCI investments	—	—	—	—	1	1	(1)	—
Total comprehensive income	—	—	—	(96)	2	(94)	64	(30)
Common share dividends	—	—	—	(34)	—	(34)	—	(34)
Preferred share dividends	—	—	—	(30)	—	(30)	—	(30)
Shares purchased under NCIB *(Note 15)*	(20)	—	—	6	—	(14)	—	(14)
Changes in non-controlling interests in TransAlta Renewables *(Note 3 and 8)*	—	—	—	20	4	24	126	150
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests *(Note 8)*	—	—	—	—	—	—	(131)	(131)
Balance, Sept. 30, 2018	3,074	942	11	(1,357)	495	3,165	1,119	4,284

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2019**	2018	**2019**	2018
Operating activities				
Net earnings (loss)	**77**	(67)	**73**	(31)
Depreciation and amortization *(Note 18)*	**177**	180	**524**	523
(Gain) loss on sale of assets *(Note 11)*	**3**	(1)	**20**	(1)
Accretion of provisions *(Note 6)*	**6**	6	**18**	18
Decommissioning and restoration costs settled	**(9)**	(10)	**(24)**	(23)
Deferred income tax expense (recovery) *(Note 7)*	**(4)**	(20)	**(51)**	(8)
Unrealized (gain) loss from risk management activities	**(14)**	1	**(30)**	1
Unrealized foreign exchange losses	**8**	6	**13**	23
Provisions	**5**	2	**9**	7
Asset impairment charges (reversals) *(Note 5)*	**(22)**	38	**(22)**	50
Other non-cash items	**9**	53	**16**	104
Cash flow from operations before changes in working capital	**236**	188	**546**	663
Change in non-cash operating working capital balances	**92**	(29)	**122**	25
Cash flow from operating activities	**328**	159	**668**	688
Investing activities				
Additions to property, plant, and equipment *(Note 11)*	**(96)**	(93)	**(240)**	(176)
Additions to intangibles	**(4)**	(6)	**(10)**	(16)
Restricted cash *(Note 13)*	**14**	(35)	**49**	(35)
Acquisition of renewable energy development projects *(Note 3)*	**—**	—	**(32)**	(30)
Investment in the Pioneer Pipeline *(Note 3)*	**—**	—	**(83)**	—
Proceeds on sale of property, plant, and equipment	**3**	(1)	**5**	—
Realized gains (losses) on financial instruments	**(1)**	—	**2**	—
Decrease in finance lease receivable	**7**	15	**19**	44
Increase (decrease) in loan receivable	**(5)**	2	**(9)**	2
Other	**(4)**	4	**6**	5
Change in non-cash investing working capital balances	**(5)**	(21)	**(28)**	(88)
Cash flow from (used in) investing activities	**(91)**	(135)	**(321)**	(294)
Financing activities				
Net increase (repayment) in borrowings under credit facilities *(Note 13)*	**(40)**	127	**(179)**	231
Repayment of long-term debt *(Note 13)*	**(17)**	(412)	**(71)**	(1,137)
Issuance of long-term debt *(Note 13)*	**—**	345	**—**	345
Issuance of exchangeable securities *(Note 14)*	**—**	—	**350**	—
Dividends paid on common shares *(Note 15)*	**(11)**	(11)	**(34)**	(34)
Dividends paid on preferred shares *(Note 16)*	**(20)**	(20)	**(30)**	(30)
Net proceeds on sale of non-controlling interest in subsidiary *(Note 3)*	**—**	—	**—**	144
Repurchase of common shares under NCIB *(Note 15)*	**(9)**	(10)	**(27)**	(14)
Realized gains on financial instruments	**—**	—	**—**	48
Distributions paid to subsidiaries' non-controlling interests *(Note 8)*	**(29)**	(42)	**(85)**	(123)
Decrease in lease obligations *(Note 13)*	**(5)**	(5)	**(16)**	(13)
Change in non-cash financing working capital balances	**12**	—	**11**	—
Financing fees	**—**	(23)	**(28)**	(30)
Cash flow used in financing activities	**(119)**	(51)	**(109)**	(613)
Cash flow from operating, investing, and financing activities	**118**	(27)	**238**	(219)
Effect of translation on foreign currency cash	**—**	(1)	**(1)**	—
Increase in cash and cash equivalents	**118**	(28)	**237**	(219)
Cash and cash equivalents, beginning of period	**208**	123	**89**	314
Cash and cash equivalents, end of period	**326**	95	**326**	95
Cash income taxes paid	**9**	4	**24**	79
Cash interest paid	**43**	30	**128**	134

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 accordance 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 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 annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation's most recent 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 Nov. 6, 2019.

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. 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. Refer to Note 2(Z) of the Corporation's most recent annual consolidated financial statements.

2. Significant Accounting Policies

A. Current Accounting Changes

I. IFRS 16 *Leases*
The Corporation has adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* (IAS 17) or International Financial Reporting Interpretations Committee Interpretation 4 *Determining whether an arrangement contains a lease*. As a result of the IFRS 16 adoption, the Corporation has changed its accounting policy for leases, which is outlined below.

The Corporation has elected to adopt IFRS 16 using the modified retrospective approach on transition. Comparative information has not been restated and is reported under IAS 17. Refer to the Corporation's most recent annual consolidated financial statements for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard of $3 million in Deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and for low value leases;
- Excluding initial direct costs for the measurement of the right of use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;
- Adjusting the right of use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

Impact on the financial statements
Lessee
The Corporation recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on Jan. 1, 2019 was 5.71%.

The following table reconciles the Corporation's operating lease commitments at Dec. 31, 2018, as previously disclosed in the Corporation’s annual consolidated financial statements, to the lease obligations recognized on initial application of IFRS 16 at Jan. 1, 2019 and included in credit facilities, long-term debt and lease obligations on the statement of financial position.

Non-cancellable operating lease commitments disclosed at Dec. 31, 2018	80
Less: Exemption for low value leases	(1)
Add: Extension and termination options reasonably certain to be exercised	4
	83
Discounted using the incremental borrowing rate at Jan. 1, 2019	(31)
New lease liabilities recognized as at Jan. 1, 2019	**52**
Add: 2018 finance lease obligations	63
Less: 2018 finance lease obligations that do not meet the IFRS 16 definition of a lease	(32)
Lease liabilities as at Jan. 1, 2019	**83**

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of $85 million, including $38 million that was previously included in property, plant and equipment (PP&E), intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16, resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in Deficit.

Refer to the discussion below, and to Note 12 for a breakdown of the Corporation's leases.

Lessor
Several of the Corporation's long term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for applying IFRS 15 *Revenue from Contracts with Customers.* No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

Impact of the new definition of a lease
The change in the definition of a lease mainly relates to the concept of control. Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

The Corporation applied the definition of a lease and related guidance set out in IFRS 16 to all lease contracts in existence at Dec. 31, 2018. In preparation for the first time application of IFRS 16, all relevant contractual arrangements were reviewed to assess if the contract meets the new definition of a lease.

Impact on lessee accounting
For all contracts that meet the definition of a lease under IFRS 16 in which TransAlta is the lessee, and do not meet the exemption for short term or low value leases, the Corporation:

- Recognizes right of use assets and lease liabilities in the consolidated statements of financial position, initially measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate or rate implicit in the lease;
- Recognizes depreciation of the right of use assets and interest expense on lease obligations in the consolidated statement of earnings (loss);
- Recognizes the principal repayments on lease obligations as financing activities and interest payments on lease obligations as operating activities in the consolidated statement of cash flow.

For short term and low value leases, the Corporation recognizes the lease payments as an operating expense. Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right of use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

For new leases beginning after Jan. 1, 2019, the right of use asset is initially measured at an amount equal to the lease liability and is adjusted for any payments made at or before the commencement date, plus any initial direct cost incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

For new leases beginning after Jan. 1, 2019, the lease liability is initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. The lease liability is re-measured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation’s estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the carrying amount of the right of use asset, or is recorded in profit or loss if the carrying amount of the right of use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Corporation is reasonably certain to exercise that option and periods covered by an option to terminate if the Corporation is reasonably certain not to exercise that option.

Right of use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right of use asset reflects that the Corporation expects to exercise the purchase option, the related right of use asset is depreciated over the useful life of the underlying asset.

Impact on lessor accounting
IFRS 16 does not substantially change lessor accounting. Under IFRS 16, a lessor continues to classify leases as either finance leases or operating leases and accounts for those two types of leases differently.

Leases for which the Corporation is lessor are classified as finance or operating leases. Whenever the terms of the lease transfers substantially all the risk and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as an operating lease.

When the Corporation has subleased all or a portion of an asset it is leasing and for which it remains the primary obliger under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right of use asset arising from the head lease.

II. Change in Estimates
Canadian Coal
During the third quarter of 2019, the Corporation adjusted the useful lives of of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see Note 3A for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the nine months ended Sept. 30, 2019 increased by approximately $4 million and the 2019 full year depreciation expense is expected to increase between $15 million to $17 million, excluding the impact of acquiring the remaining 50 per cent ownership of Keephills 3 (see Note 3C for further details).

In 2018, as a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(O) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the nine months ended Sept. 30, 2018 increased by approximately $29 million and the 2018 full year depreciation expense increased by approximately $38 million.

Wind and Solar
During the third quarter, the allocation of the costs recognized for the components of the Wind and Solar property, plant and equipment and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. As a result, depreciation expense for the three and nine months ended Sept. 30, 2019 increased by approximately $7 million and the 2019 full year depreciation expense is expected to increase by approximately $10 million.

Sheerness
During the second quarter of 2019, the Corporation adjusted the useful life of its Sheerness assets to align with the dual fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the nine months ended Sept. 30, 2019 decreased by approximately $5 million and the 2019 full year depreciation expense is expected to decrease by approximately $11 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia
During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that Coalview Centralia, LLC (“Coalview”) will be able to complete the fine coal recovery and reclamation work as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $109 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in immediate recognition for the full $109 million, through asset impairment charges in net earnings.

TransAlta estimates that the undiscounted amount of cash flow required to settle this additional obligation is approximately $142 million, which will be incurred between 2021 and 2035. The provision may be revised in compliance with the Corporation's accounting policies, dependent upon future operating decisions and as more information becomes available.

B. Future Accounting Changes

Effective Oct. 1, 2019, the Corporation has early-adopted amendments to IFRS 3 Bu*siness Combinations*, in advance of its mandatory effective date of Jan. 1, 2020. TransAlta adopted the IFRS 3 amendments prospectively and therefore the comparative information presented for 2018 has not been restated. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. Specifically, these amendments:

- clarify the minimum requirements for a business, whereby at minimum, an input and a substantive process that together significantly contribute to the ability to create output must be present;
- remove the assessment of whether market participants are capable of replacing any missing elements so that the assessment is based on what has been acquired in its current state and condition, rather than on whether market participants are capable of replacing any missing elements, for example, by integrating the acquired activities and assets;
- add guidance to help entities assess whether an acquired process is substantive, which requires more persuasive evidence when there are no outputs, because the existence of outputs provides some evidence that the acquired set of activities and assets is a business;
- narrow the definition of outputs to focus on goods or services provided to customers, investment income or other income from ordinary activities; and
- introduce an optional fair value concentration test, that can be applied on a transaction-by-transaction basis, to permit a simplified assessment of whether an acquired set of activities and assets are not a business. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The Corporation elected to apply the optional fair value concentration test to its acquisition of the remaining 50 per cent interest in Keephills 3 - see Note 3C for further details. There are no other impacts to the asset acquisitions that were completed during the nine months ended Sept. 30, 2019.

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. Clean Energy Investment Plan and Dividend Policy

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in onsite generation and renewable energy. TransAlta is currently pursuing opportunities of up to approximately $1.9 billion as part of this plan, including approximately $800 million of renewable energy projects already under construction.

TransAlta's plan included converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The Corporation is also advancing permitting to convert one, or possibly two, of its units to highly efficient combined cycle natural gas units. The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of the Alberta thermal assets; and
- Significantly reducing air emissions and costs.

On Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F class gas turbines and related equipment for $84 million. These turbines will be redeployed to TransAlta's Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined cycle unit. The transaction also results in the Corporation assuming long-term non-unit contingent power purchase agreements for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada). TransAlta expects to issue Limited Notice to Proceed ("LNTP") in 2020 and Full Notice to Proceed ("FNTP") in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million. In conjunction with the Sundance Unit 5 permitting, TransAlta is also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined cycle unit, depending on market fundamentals.

The Corporation’s Clean Energy Investment Plan also consists of the four wind projects in the United States and Alberta that are currently under construction and a cogeneration facility. These projects are underpinned by long-term power purchase agreements with highly creditworthy counterparties.

B. Agreement to Construct and Own a Cogeneration Plant in Alberta

On Oct. 1, 2019, TransAlta and SemCAMS Midstream ULC (“SemCAMS”) announced that they have entered into definitive agreements to develop, construct and operate a 40MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS will purchase a fifty percent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta Power market by TransAlta.

C. TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed the transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the 466 MW Genesee 3 facility for Capital Power's 50 per cent ownership interest in the 463MW Keephills 3 facility. As a result, TransAlta owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The purchase prices for each non-operating interest largely offset each other, resulting in a net payment of $10 million from Capital Power to TransAlta, subject to working capital settlements. Final working capital true ups and settlements will occur within 90 days of the closing date.

As discussed in Note 2B, on closing, the Corporation has early-adopted 2020 amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test. The Corporation elected to apply the optional fair value concentration test to its acquisition of the non-operating interest in Keephills 3, through which it was determined that greater than 90% of the fair value was concentrated in the property, plant and equipment acquired. As a result, the acquisition was determined to not be a business and IFRS 3 requirements were not applied and the existing carrying amount of the owned 50% of Keephills 3 was not required to be written down to fair value. Consequently, the acquisition has been accounted for as an asset acquisition, with the following carrying amounts assigned based on relative fair values:

Working capital	11
Property, plant and equipment	308
Other assets	3
Other liabilities	(2)
Decommissioning and other provisions	(19)
Total acquisition cost	**301**

As at Sept. 30, 2019, the Corporation has re-classified the assets and liabilities related to the Genesee 3 disposal group, included in the Canadian Coal segment, as held for sale on the statement of financial position, as detailed below:

Items moved to assets held for sale:		**Items moved to liabilities held for sale:**	
Prepaid expenses(1)	1	Current portion of decommissioning and other provisions	9
Inventory(1)	8		
Property, plant and equipment	219	Decommissioning and other provisions	23
Intangibles	28		
Other assets	10		
Total assets held for sale	**266**	**Total liabilities held for sale**	**32**

(1) Working capital items were settled through a separate cash payment on closing.

D. Termination of the Alberta Sundance Power Purchase Arrangements

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective March 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective March 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation.

On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full amount it was seeking to recover of $56 million, plus GST and interest.

E. Strategic Investment by Brookfield

On March 25, 2019, the Corporation announced that it had entered into an agreement whereby Brookfield Renewable Partners or its affiliates (collectively “Brookfield”) agreed to invest $750 million in TransAlta through the purchase of exchangeable securities ("Investment Agreement"), which are exchangeable into an equity ownership interest in TransAlta’s Alberta PPA Hydro Assets in the future at a value based on a multiple of the Alberta PPA Hydro Assets’ future EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for 7% unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions precedent.

Upon entering into the Investment Agreement and as required in the terms of the agreement, the Corporation paid to Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures. See Note 14 for further details.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than 9% at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share.

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within the next three years.

F. Normal Course Issuer Bid

On May 27, 2019 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 29, 2019, and ends on May 28, 2020, 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.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the nine months ended Sept. 30, 2019, the Corporation purchased and cancelled 3,133,200 common shares at an average price of $8.57 per common share, for a total cost of $27 million. See Note 15 for further details.

G. Skookumchuck Wind Energy Facility

On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW wind facility currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with Puget Sound Energy. TransAlta will make its investment when the facility reaches its commercial operation date, which is expected to be in the first quarter of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be $150 to $160 million.

H. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 percent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Throughput of approximately 130 MMcf/day of natural gas commenced flowing through the Pioneer Pipeline on November 1, 2019. Tidewater and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, was approximately $100 million.

During the nine months ended Sept. 30, 2019, TransAlta invested $83 million in the Pioneer Pipeline and $98 million life-to-date. The Pioneer Pipeline is held in a separate entity that is a joint operation with Tidewater. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation. The Pioneer Pipeline is classified as a joint operation, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations. If these facts and circumstances change, the classification of the joint arrangement may change.

I. Mothballing of Sundance Units

On March 8, 2019, the Corporation announced that the Alberta Electric System Operator ("AESO") granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020. The extensions were requested by TransAlta based on TransAlta's assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

J. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire interests in two construction-ready projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year Power Purchase Arrangement ("PPA") with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the fourth quarter of 2019. A subsidiary of TransAlta acquired Big Level on Mar. 1, 2018.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables using its existing liquidity and tax equity and are estimated to be approximately US $250 million to US$270 million, including capitalized interest expense. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, the Corporation recognized $50 million for assets under construction in property, plant and equipment and $15 million in intangibles. The TransAlta subsidiary also paid the final holdback for the Big Level development project of $7 million (US$5 million) on the closing of Antrim. Upon the closing of the purchase of Antrim, TransAlta Renewables funded an additional $70 million (US$52 million) by subscribing for an interest-bearing promissory note issued by the project entity. During the first nine months of 2019, TransAlta Renewables funded $93 million (US$69 million) of construction costs.

During the third quarter of 2019, subsidiaries of TransAlta entered into final agreements with an external party for a planned tax equity investment in the Big Level and Antrim wind projects. The total financing is expected to be approximately US$125 million to US$135 million, with initial funding of approximately US$35 million and US$90 million, respectively, coinciding with Antrim and Big Level each achieving commercial operation, subject to customary conditions. The tax equity financing will be classified as long-term debt on the statement of financial position.

K. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

On May 31, 2018, TransAlta Renewables acquired from the Corporation an economic interest in the 50 MW Lakeswind wind farm in Minnesota and 21 MW of solar projects located in Massachusetts ("Mass Solar") through the subscription of tracking preferred shares of a subsidiary of the Corporation. In addition, TransAlta Renewables acquired from the Corporation ownership of the 20 MW Kent Breeze wind farm located in Ontario. The total purchase price for the three assets, was approximately $166 million, including the assumption of $62 million of tax equity obligations and project debt, for net cash consideration of $104 million in equity value. The Corporation continues to operate these assets on behalf of TransAlta Renewables.

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar, in order to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge in the second quarter of 2018, of which $11 million was recorded against PP&E, and $1 million against intangibles.

L. TransAlta Renewables Closes $150 Million Offering of Common Shares

On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters (the "Offering"). The common shares were issued at a price of $12.65 per common share for gross proceeds of approximately $150 million ($144 million net proceeds).

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which were drawn in order to fund recent acquisitions. The additional liquidity under the credit facility will be used for general corporate purposes, including ongoing construction costs associated with the US wind development, described above.

The Corporation did not purchase any additional common shares under the Offering. See Note 8 for further details of TransAlta's ownership of TransAlta Renewables.

M. $345 Million Financing

The Corporation monetized the payments under the OCA with the Government of Alberta on July 20, 2018, upon the closing of an approximate $345 million bond offering by its indirect wholly-owned subsidiary, TransAlta OCP LP ("TransAlta OCP"), by way of private placement which is secured by, among other things, a first ranking charge over the OCA payments payable by the Government of Alberta. The amortizing bonds bear interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The bonds have a rating of BBB, with a Stable trend, by DBRS. Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

N. Early Redemption of $400 million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of $400 million . The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest.

O. Sundance Unit 2 Retirement

On July 19, 2018, the Corporation's Board approved the retirement of Sundance Unit 2 effective July 31, 2018. The decision was driven largely by Sundance Unit 2's age, size, and short useful life relative to other units, and the capital requirements needed to return the unit to service. The retirement is consistent with our transition strategy to clean power by 2025. The Corporation recognized an impairment charge of $38 million ($28 million after-tax) in the third quarter of 2018.

P. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense.

4. Revenue

Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and green attributes, leasing of power facilities, and from energy marketing and trading 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 Sept. 30, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	104	3	49	21	43	37	—	—	257
Revenue from leases	17	—	—	16	—	—	—	—	33
Revenue from derivatives[(1)]	16	88	(3)	—	(1)	—	26	2	128
Government incentives	—	—	—	—	2	—	—	—	2
Revenue from other[(2)]	71	93	—	2	8	3	—	(4)	173
Total Revenue	208	184	46	39	52	40	26	(2)	593
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	12	3	—	—	6	—	—	—	21
Over time	92	—	49	21	37	37	—	—	236
Total Revenue from contracts with customers	104	3	49	21	43	37	—	—	257

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.
(2) Includes merchant revenue and other miscellaneous.

3 months ended Sept. 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	109	2	52	22	33	30	—	—	248
Revenue from leases	17	—	—	16	4	3	—	—	40
Revenue from derivatives(1)	(2)	14	—	—	8	—	18	—	38
Government incentives	—	—	—	—	2	—	—	—	2
Revenue from other(2)	108	142	2	3	8	4	—	(2)	265
Total Revenue	232	158	54	41	55	37	18	(2)	593
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	9	2	—	—	2	—	—	—	13
Over time	100	—	52	22	31	30	—	—	235
Total Revenue from contracts with customers	109	2	52	22	33	30	—	—	248

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.
(2) Includes merchant revenue and other miscellaneous.

9 months ended Sept. 30, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues from contracts with customers	**300**	**7**	**158**	**65**	**175**	**114**	**—**	**—**	**819**
Revenue from leases	**49**	**—**	**—**	**50**	**—**	**—**	**—**	**—**	**99**
Revenue from derivatives(1)	**(36)**	**123**	**(1)**	**—**	**12**	**—**	**98**	**4**	**200**
Government incentives	**—**	**—**	**—**	**—**	**6**	**—**	**—**	**—**	**6**
Revenue from other(2)	**295**	**286**	**1**	**5**	**20**	**12**	**—**	**(5)**	**614**
Total Revenue	**608**	**416**	**158**	**120**	**213**	**126**	**98**	**(1)**	**1,738**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	**35**	**7**	**—**	**—**	**21**	**—**	**—**	**—**	**63**
Over time	**265**	**—**	**158**	**65**	**154**	**114**	**—**	**—**	**756**
Total Revenue from contracts with customers	**300**	**7**	**158**	**65**	**175**	**114**	**—**	**—**	**819**

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.
(2) Includes merchant revenue and other miscellaneous.

9 months ended Sept. 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	410	6	160	67	143	106	—	—	892
Revenue from leases	51	—	—	51	17	6	—	—	125
Revenue from derivatives(1)	(7)	126	5	—	(11)	—	48	—	161
Government incentives	—	—	—	—	12	—	—	—	12
Revenue from other(2)	226	164	2	5	31	15	—	(6)	437
Total Revenue	680	296	167	123	192	127	48	(6)	1,627
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	30	6	—	—	8	—	—	—	44
Over time	380	—	160	67	135	106	—	—	848
Total Revenue from contracts with customers	410	6	160	67	143	106	—	—	892

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.
(2) Includes merchant revenue and other miscellaneous.

5. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each cash generating unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. 2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the CGU exceeded the carrying value by a substantial margin, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period included cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	**2016**
Mid-Columbia annual average power prices	US$30.37 to US$41.94 per MWh	US$22.00 to US$46.00 per MWh
On-highway diesel fuel on coal shipments	US$2.35 to US$2.40 per gallon	US$1.69 to US$2.09 per gallon
Discount rates	5.2 to 6.4 per cent	5.4 to 5.7 per cent

Refer to Note 2 for details on the $109 million expense related to the Centralia mine decommissioning and restoration provision.

B. 2018

Sundance Unit 2

In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on July 31, 2018. Discounting did not have a material impact.

Lakeswind and Kent Breeze

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 3K). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (See Note 11).

C. Project Development Costs

During the three and nine months ended Sept. 30, 2019, the Corporation wrote off $18 million in project development costs related to projects that are no longer proceeding.

6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Interest on debt	**40**	44	**123**	142
Interest on exchangeable securities *(Note 14)*	**7**	—	**12**	—
Interest income	**(4)**	(2)	**(9)**	(8)
Capitalized interest	**(2)**	(1)	**(4)**	(1)
Loss on early redemption of US Senior Notes *(Note 13)*	**—**	19	**—**	24
Interest on lease obligations	**1**	—	**3**	2
Credit facility fees and bank charges	**4**	4	**11**	10
Other interest and fees(1)	**3**	3	**7**	13
Accretion of provisions	**6**	6	**18**	18
Net interest expense	**55**	73	**161**	200

(1) During the nine months ended Sept. 30, 2018, approximately $5 million of costs were expensed due to project level financing that was no longer practicable.

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Current income tax expense (recovery)	**14**	(1)	**28**	18
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**12**	(24)	**(7)**	(26)
Deferred income tax recovery resulting from changes in tax rates or laws (1)	**—**	—	**(40)**	—
Deferred income tax expense arising from the writedown (recovery) of deferred income tax assets(2)	**(16)**	4	**(4)**	18
Income tax expense (recovery)	**10**	(21)	**(23)**	10

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Current income tax expense (recovery)	**14**	(1)	**28**	18
Deferred income tax recovery	**(4)**	(20)	**(51)**	(8)
Income tax expense (recovery)	**10**	(21)	**(23)**	10

(1) In the second quarter of 2019, the Corporation recognized a deferred income tax recovery of $40 million related to a decrease in the substantively enacted Alberta corporate tax rate from 12 per cent to 8 per cent. The lower tax rates will be phased in as follows: 11 per cent effective July 1, 2019; 10 per cent effective Jan. 1, 2020; 9 per cent effective Jan. 1, 2021, and 8 per cent effective Jan. 1, 2022. A deferred tax recovery of $40 million was recorded in the statement of earnings and a deferred tax expense of $3 million was recorded in the statement of other comprehensive income.

(2) During the three and nine months ended Sept. 30, 2019, the Corporation reversed a previous writedown of deferred tax assets of $16 million and $4 million, respectively (Sept. 30, 2018 - $4 million and $18 million writedown). 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 previously wrote these assets off when it was not considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses. Recognized ordinary income and other comprehensive income has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown. In addition, during the second quarter of 2019, the Alberta corporate tax rate decreased to 11 per cent effective July 1, 2019.

8. 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.

The Corporation's share of ownership and equity participation in TransAlta Renewables is as follows:

Period	Percentage
Aug. 1, 2017 to June 21, 2018	64.0
June 22, 2018 to July 30, 2018(1)	61.1
July 31, 2018 to Nov. 29, 2018(2)	61.0
Nov. 30, 2018 to Dec. 31, 2018(2)	60.9
Jan. 1, 2019 to March 31, 2019(2)	60.8
Apr. 1, 2019 to June 30, 2019(2)	60.6
Jul. 1, 2019 to Sept. 30, 2019(2)	60.5

(1) Reduction due to TransAlta Renewables common shares issuance that occurred during the second quarter of 2018. The Corporation did not participate in this common share issuance. See Note 3 for further details.
(2) As a result of TransAlta Renewables' Dividend Reinvestment Plan ("DRIP"), which allows investors to reinvest their dividends into common shares, the ownership percentage changes every month. The Corporation does not participate in the DRIP.

Amounts attributable to non-controlling interests are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Net earnings				
TransAlta Cogeneration L.P.	**7**	4	**16**	10
TransAlta Renewables	**9**	5	**51**	55
	16	9	**67**	65
Total comprehensive income				
TransAlta Cogeneration L.P.	**7**	4	**16**	10
TransAlta Renewables	**30**	3	**37**	54
	37	7	**53**	64
Cash Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**12**	23	**33**	62
TransAlta Renewables	**17**	19	**52**	61
	29	42	**85**	123

As at	**Sept. 30, 2019**	Dec. 31, 2018
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**157**	176
TransAlta Renewables	**944**	961
	1,101	1,137
Non-controlling interests per share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.5**	39.1

9. 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. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

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

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

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

c. Level III

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

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy, which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by the Corporation's risk management department. Level III fair values are calculated within the Corporation's energy trading risk management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

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. 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 volatilities and correlations, delivery volumes, and shapes.

As at	**Sept. 30, 2019**		**December 31, 2018**	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - Western US	**736**	+67 -151	801	+116 -116
Unit contingent power purchases - Eastern US	**2**	+1 -1	18	+4 -4
Structured products - Eastern US	**8**	+4 -4	6	+5 -5
Long-term wind energy sale - Eastern US	**(32)**	+21 -21	(39)	+21 -21
Others	**4**	+6 -5	9	+3 -3

i. Long-Term Power Sale - Western 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.

For periods over two years out, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2019 are US$24 to US$32 (Dec. 31, 2018 - US$20 to US$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US$4 to US$9 (Dec. 31, 2018 - US$6) price decrease or increase, respectively, in the forward power prices as a reasonably possible change.

ii. Unit Contingent Power Purchases - Eastern US

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as at fair value through profit and loss.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Sept. 30, 2019, are nil (Dec. 31, 2018 - nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2018 – 2.2 per cent to 16.9 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.1 per cent to 1.9 per cent (Dec. 31, 2018 - 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 10.6 per cent (Dec. 31, 2018 - 8.6 per cent to 27.3 per cent), which approximate one standard deviation for each input.

iii. Structured Products - Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations, or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Sept. 30, 2019, are 84 per cent to 110 per cent and 63 per cent to 100 per cent (Dec. 31, 2018 – 75 per cent to 109 per cent and 63 per cent to 104 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 3 per cent to 6 per cent (Dec. 31, 2018 - 4 per cent to 7 per cent) and a change in non-standard shape factors of approximately 4 per cent to 9 per cent (Dec. 31, 2018 - 4 per cent to 9 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Sept. 30, 2019, are 47 per cent to 55 per cent and 70 per cent (Dec. 31, 2018 – 25 per cent to 84 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 49 per cent to 53 per cent and 30 per cent, respectively (Dec. 31, 2018 - 37 per cent to 49 per cent and 30 per cent).

iv. Long-Term Wind Energy Sale - Eastern US

In relation to the acquisition of Big Level (See Note 3), 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 is expected to occur in the fourth quarter of 2019, with the contract commencing on July 1, 2019 and extending for 15 years from the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2024 and 2022, respectively. Forward power and REC price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2019 are US$41 to US$64 and US$8 (Dec. 31, 2018 - US$42 to US$68 and US$7 to US$8), respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent, a change in energy prices of US$6, and a change in REC prices of US$1 as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Sept. 30, 2019, are as follows: Level I - $1 million net liability (Dec. 31, 2018 - $3 million net asset), Level II - $12 million net asset (Dec. 31, 2018 - $19 million net liability), Level III - $676 million net asset (Dec. 31, 2018 - $695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2019 are primarily attributable to contract settlements and unfavourable foreign exchange rates, partially offset by favourable market prices during the period.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities during the nine months ended Sept. 30, 2019 and 2018, respectively:

	9 months ended Sept. 30, 2019			9 months ended Sept. 30, 2018		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**689**	**6**	**695**	719	52	771
Changes attributable to:						
Market price changes on existing contracts	**40**	**(2)**	**38**	(9)	7	(2)
Market price changes on new contracts	**—**	**11**	**11**	—	—	—
Contracts settled	**(34)**	**(14)**	**(48)**	(60)	(35)	(95)
Change in foreign exchange rates	**(22)**	**2**	**(20)**	26	—	26
Transfers into (out of) Level III	**—**	**—**	**—**	—	(4)	(4)
Net risk management assets at end of period	**673**	**3**	**676**	676	20	696
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**18**	**—**	**18**	17	—	17
Total gains (losses) included in earnings before income taxes	**(34)**	**11**	**(23)**	60	7	67
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(3)**	**(3)**	—	(28)	(28)

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 $13 million as at Sept. 30, 2019 (Dec. 31, 2018 - $2 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets during the nine months ended Sept. 30, 2019 are primarily attributable to market changes and contract settlements.

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**
Exchangeable securities - Sept. 30, 2019	**—**	**341**	**—**	**341**	**325**
Long-term debt - Sept. 30, 2019	**—**	**3,059**	**—**	**3,059**	**2,925**
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

The fair values of the Corporation's debentures, senior notes and the 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, 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 Corporation's loan receivable, the finance lease receivables and lease liabilities approximate the carrying amounts.

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. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note 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:

	9 months ended Sept. 30	
	2019	2018
Unamortized net gain at beginning of period	**49**	105
New inception gain (loss)	**1**	(14)
Change in foreign exchange rates	**—**	2
Amortization recorded in net earnings during the period	**(38)**	(43)
Unamortized net gain at end of period	**12**	50

10. Risk Management Activities

A. Risk Management Strategy

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. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: (i) financial exposure management and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk, and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in a foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

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

As at Sept. 30, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**82**	**23**	**105**
Long-term	**587**	**(5)**	**582**
Net commodity risk management assets (liabilities)	**669**	**18**	**687**
Other			
Current	**—**	**4**	**4**
Long-term	**2**	**7**	**9**
Net other risk management assets (liabilities)	**2**	**11**	**13**
Total net risk management assets (liabilities)	**671**	**29**	**700**

As at Dec. 31, 2018

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	59	—	59
Long-term	628	(8)	620
Net commodity risk management assets (liabilities)	687	(8)	679
Other			
Current	—	(3)	(3)
Long-term	—	1	1
Net other risk management assets (liabilities)	—	(2)	(2)
Total net risk management assets (liabilities)	687	(10)	677

On May 31, 2019, the Corporation de-designated $30 million of US denominated debt, leaving a total of USD $370 million, designated as a part of the hedge of TransAlta's net investment in foreign operations.

C. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments, which are also more fully discussed in Note 15 of the Corporation's most recent annual consolidated financial statements.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

i. Commodity Price Risk – 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.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2019, associated with the Corporation's proprietary trading activities was $2 million (Dec. 31, 2018 - $2 million).

ii. Commodity Price Risk - Generation

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

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred in AOCI until settlement, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Sept. 30, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $20 million (Dec. 31, 2018 - $18 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2019, associated with these transactions was $6 million (Dec. 31, 2018 - $13 million).

b. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar ("AUD"), as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers. Further discussion on Currency Rate Risk can be found in Note 15(C)(I)(c) of the Corporation's most recent annual consolidated financial statements.

II. Credit Risk
Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

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 Sept. 30, 2019:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1)	84	16	**100**	**452**
Long-term finance lease receivables	100	—	**100**	**179**
Risk management assets(1)	99	1	**100**	**780**
Loan and notes receivable(2)	—	100	**100**	**47**
Total				**1,458**

(1) Letters of credit and cash and cash equivalents are generally the primary types of collateral held as security related to some of these amounts.
(2) The loan receivable of $47 million due from the Corporation's partner at Kent Hills wind farm. The counterparty has no external credit ratings.

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 Sept. 30, 2019, was $14 million (Dec. 31, 2018 - $13 million).

III. Liquidity Risk
Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. As at Sept. 30, 2019, TransAlta maintains investment grade ratings from one credit rating agencies and below investment grade ratings from three credit rating agencies. Between 2019 and 2021, we have approximately $601 million of debt maturing. We will receive the proceeds from the issuance to Brookfield of the second tranche of exchangeable securities of $400 million in the fourth quarter of 2020. See Note 14 for further details.

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:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Accounts payable and accrued liabilities	357	—	—	—	—	—	357
Long-term debt[1]	26	486	89	624	301	1,426	2,952
Exchangeable securities[2]	—	—	—	—	—	350	350
Commodity risk management (assets) liabilities	(33)	(100)	(103)	(128)	(124)	(199)	(687)
Other risk management (assets) liabilities	(1)	(5)	—	(8)	1	—	(13)
Lease obligations	5	17	12	7	3	26	70
Interest on long-term debt and lease obligations[3]	65	147	123	116	87	706	1,244
Interest on exchangeable securities[2, 3]	6	25	25	25	25	25	131
Dividends payable	37	—	—	—	—	—	37
Total	**462**	**570**	**146**	**636**	**293**	**2,334**	**4,441**

(1) Excludes impact of hedge accounting.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. See Note 14 for further details.
(3) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

D. Collateral and Contingent Features in Derivative Instruments

Collateral is posted based on negotiated terms with counterparties, which can include 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. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Sept. 30, 2019, the Corporation had posted collateral of $114 million (Dec. 31, 2018 - $120 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 could result in the Corporation having to post an additional $26 million (Dec. 31, 2018 - $120 million) of collateral to its counterparties.

11. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
As at As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
Adjustments on implementation of IFRS 16 *(Note 2)*[2]	—	—	—	(4)	(58)	—	—	(62)
Additions[3]	—	—	—	—	—	231	109	340
Acquisitions *(Note 3)*	—	—	—	—	—	50	—	50
Asset impairment (charges) reversals *(Note 5)*	—	151	—	(2)	—	—	—	149
Depreciation	—	(224)	(58)	(99)	(71)	—	(12)	(464)
Revisions and additions to decommissioning and restoration costs	—	6	2	2	26	—	—	36
Retirement of assets and disposals[4]	(2)	—	(2)	(4)	(9)	—	(17)	(34)
Change in foreign exchange rates	(1)	(7)	(32)	(6)	(1)	(3)	(5)	(55)
Transfers[5]	—	(148)	22	12	34	(139)	—	(219)
As at Sept. 30, 2019	**91**	**1,950**	**768**	**2,024**	**429**	**339**	**304**	**5,905**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive, or planned maintenance.
(2) Includes $33 million transferred to right of use assets and $29 million of finance lease assets that were derecognized on implementation of IFRS 16 (see Note 2 for further details).
(3) Includes cash additions of $240 million and $100 million relating to the Pioneer Pipeline.
(4) During the second quarter of 2019, Centralia sold boiler parts included in Capital spares and other for a net loss of $17 million, which was recognized in other gains (losses) on the statement of earnings (loss).
(5) The net impact of the transfers relates to the Genesee 3 assets that are presented as assets held for sale. See Note 3C for further details.

12. Right of Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right of use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
New leases recognized Jan. 1, 2019	29	22	1	—	52
Adjustments on recognition[1]	(1)	(4)	—	—	(5)
Transfers from PP&E, intangibles and other assets	—	—	3	35	38
As at Jan. 1, 2019	28	18	4	35	85
Additions	—	2	—	1	3
Depreciation	(1)	(3)	(1)	(8)	(13)
Transfers	—	—	—	(1)	(1)
As at Sept. 30, 2019	**27**	**17**	**3**	**27**	**74**

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

For the three and nine months ended Sept. 30, 2019, TransAlta paid $6 million and $19 million, respectively, related to the above leases, consisting of $1 million and $3 million in interest, respectively, and $5 million and $16 million in principal repayments, respectively.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. For the three and nine months ended Sept. 30, 2019, the Corporation expensed $1 million and $3 million, respectively, in variable land lease payments for these leases. For further information regarding leases please refer to Notes 4, 6, 10, 13 and 17.

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

A. Amounts Outstanding

The amounts outstanding are as follows:

As at	Sept. 30, 2019			Dec. 31, 2018		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**160**	**160**	**3.4%**	339	339	3.8%
Debentures	**647**	**651**	**5.8%**	647	651	5.8%
Senior notes(3)	**917**	**927**	**5.4%**	943	955	5.4%
Non-recourse(4)	**1,168**	**1,181**	**4.3%**	1,236	1,250	4.4%
Other(5)	**33**	**33**	**9.2%**	39	39	9.2%
	2,925	**2,952**		3,204	3,234	
Lease obligations	**70**			63		
	2,995			3,267		
Less: current portion of long-term debt	**(85)**			(130)		
Less: current portion of lease obligations	**(18)**			(18)		
Total current long-term debt and lease obligations	**(103)**			(148)		
Total credit facilities, long-term debt, and lease obligations	**2,892**			3,119		

(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 Sept. 30, 2019 - US$0.7 billion (Dec. 31, 2018 - US$0.7 billion).
(4) Includes US$1 million at Sept. 30, 2019 (Dec. 31, 2018 - US$1 million).
(5) Includes US$18 million at Sept. 30, 2019 (Dec. 31, 2018 - US$21 million) of tax equity financing.

The Corporation has a total of $2.2 billion (Dec. 31, 2018 - $2.0 billion) of committed credit facilities, comprised of the Corporation's $1.25 billion (Dec. 31, 2018 - $1.25 billion) committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $0.7 billion (Dec. 31, 2018 - $0.5 billion), and the Corporation's $0.2 billion (Dec. 31, 2018 - $0.2 billion) committed bilateral facilities. These facilities were renewed, and TransAlta Renewables' facility was increased by $200 million, during the second quarter of 2019 and expire in 2023, 2023, and 2021 respectively. The $1.95 billion (Dec. 31, 2018 - $1.75 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business.

In total, $1.4 billion (Dec. 31, 2018 - $0.9 billion) is not drawn. At Sept. 30, 2019, the $0.8 billion (Dec. 31, 2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $160 million (Dec. 31, 2018 - $339 million) and letters of credit of $661 million (Dec. 31, 2018 - $720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, the Corporation also has $326 million of available cash and cash equivalents.

The Corporation's total outstanding letters of credit as at Sept. 30, 2019 were $661 million (Dec. 31, 2018 - $720 million), including TransAlta Renewables outstanding letters of credit of $93 million (Dec. 31, 2018 - $77 million) with no (Dec. 31, 2018 - nil) amounts exercised by third parties under these arrangements. The Corporation has two uncommitted $100 million demand letter of credit facilities and TransAlta Renewables has an uncommitted $100 million demand letter of credit facility.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Sept. 30, 2019, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Corporation's subsidiaries have issued non-recourse bonds of $1,167 million (Dec. 31, 2018 - $1,235 million) that are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2019. At Sept. 30, 2019, $27 million (Dec. 31, 2018 -$33 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Sept. 30, 2019.

C. Security

Non-recourse debts of $740 million in total (Dec. 31, 2018 - $766 million) are each secured by a first ranking charge over all of the respective assets of each of the Corporation's subsidiaries that issued the bonds, which includes property, plant and equipment with total carrying amounts of $982 million at Sept. 30, 2019 (Dec. 31, 2018 - $1,021 million) and intangible assets with total carrying amounts of $65 million (Dec. 31, 2018 - $70 million). At Sept. 30, 2019, a non-recourse bond of approximately $121 million (Dec. 31, 2018 - $127 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds with a carrying value of $306 million at Sept. 30, 2019 (Dec. 31, 2018 - $342 million) are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

D. Restricted Cash

The Corporation has nil (Dec. 31, 2018 - $31 million) restricted cash related to the Kent Hills project financing. The Corporation has $17 million (Dec. 31, 2018 - $35 million) of restricted cash related to the TransAlta OCP bonds.

14. Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into an Investment Agreement whereby Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Hydro Assets' future EBITDA ("Option to Exchange"). The Exchangeable Securities will consist of the $350 million debentures and $400 million preferred shares which will be issued in October of 2020.

A. $350 Million Unsecured Subordinated Debentures

As at	Sept. 30, 2019		
	Carrying value	Face value	Interest
Exchangeable debentures - due May 1, 2039	325	350	7.0%

B. Option to Exchange

As at	Sept. 30, 2019	
Description	Base fair value	Sensitivity
Option to Exchange - embedded derivative	—	+30 -24

The Investment Agreement allows Brookfield the Option to Exchange all of the outstanding Exchangeable Securities into an equity ownership interest in 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 and therefore it is 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 is 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 discount rate of 1 per cent is a reasonably possible change.

C. Management Fee

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation, and maximizing the value, of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual Management Fee of $1.5 million for six years beginning May 1, 2019, which is recognized in the operations, maintenance and administration expense on the statement of earnings (loss).

15. Common Shares

A. Issued and Outstanding

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

	9 months ended Sept. 30			
	2019		2018	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**284.6**	**3,059**	287.9	3,094
Shares purchased and retired under NCIB	**(3.1)**	**(34)**	(1.9)	(20)
Stock options exercised	**0.1**	**1**	—	—
	281.6	**3,026**	286.0	3,074
Amounts receivable under Employee Share Purchase Plan	**—**	**—**	—	—
Issued and outstanding, end of period	**281.6**	**3,026**	286.0	3,074

B. NCIB Program

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 retained earnings.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the nine months ended:

	Sept. 30, 2019	Sept. 30, 2018
Total shares purchased	**3,133,200**	1,907,200
Average purchase price per share	**$ 8.57**	$ 7.34
Total cost	**27**	14
Weighted average book value of shares cancelled	**34**	20
Increase to retained earnings	**7**	**6**

C. Earnings per Share

	3 months ended Sept. 30		9 months ended Sept. 30	
	2019	2018	**2019**	2018
Net earnings (loss) attributable to common shareholders	**51**	(86)	**(14)**	(126)
Basic and diluted weighted average number of common shareholders outstanding (millions)	**282**	287	**284**	287
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.30)	**(0.05)**	(0.44)

D. Dividends

On July 16, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Oct. 1, 2019.

On Oct. 9, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2020.

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

E. Stock Options

The stock options granted to executive officers of the Corporation during the nine months ended Sept. 30, 2019 and 2018 are as follows:

Grant month	**Number of stock options granted** *(millions)*	**Exercise price**	**Vesting period** *(years)*	**Expiration length** *(years)*
January 2019[1]	1.2	$ 5.59	3	7
January 2018	0.7	$ 7.45	3	7

(1) Certain stock options were forfeited when an executive officer left the Corporation.

F. Share-Based Payment Grants

During the third quarter of 2019, as a result of the Corporation's change in its intended settlement policy, the accounting classification of certain of its share-based payment grants changed from cash-settled to equity-settled. Pursuant to the Corporation's plan, it retains the discretion to determine whether payments on settlement are made in cash or equity. These grants have been accounted for as equity-settled grants from the date of policy change, with fair values determined as at that date. The liability for the cash-settled grants ($12 million) has been derecognized and the equity-settled amount ($11 million) has been recognized in contributed surplus, with the net difference of $1 million representing the cumulative change in compensation expense. No changes were made to the vesting or performance conditions associated with the awards.

16. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares, other than the Series B preferred shares which are non-voting cumulative redeemable floating rate first preferred shares.

During the third quarter of 2019, Series G preferred shareholders had the option to convert into Cumulative Redeemable Floating Rate Preferred Shares, Series H ("Series H Shares"). However, there were only 140,730 Series G Shares tendered for conversion, which was less than the one million shares required to give effect to conversion into Series H Shares. As a result, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2019 and the dividend rate on the Series G shares was reset to 4.988 per cent for the subsequent five year period.

As at Sept. 30, 2019 and Dec. 31, 2018, the Corporation had 10.2 million Series A, 1.8 million Series B, 11.0 million Series C, 9.0 million Series E, 6.6 million Series G shares issued and outstanding.

B. Dividends

The following summarizes the preferred share dividends declared within the three and nine months ended Sept. 30:

		3 months ended Sept. 30		9 months ended Sept. 30	
Series	**Quarterly amounts per share**	**2019**	2018	**2019**(1)	2018
A	0.16931	**1**	2	**3**	5
B	0.23422(2)	**1**	—	**1**	1
C	0.25169	**3**	2	**6**	8
E	0.32463	**3**	3	**6**	9
G	0.33125	**2**	3	**4**	7
Total for period		**10**	10	**20**	30

(1) No dividends were declared in the first quarter of 2019 as the quarterly dividend related to the period covering the first quarter of 2019 was declared in December 2018.
(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. Approximately $400 thousand and $800 thousand dividends were declared in the three and nine months ended Sept. 30, 2019.

On Oct. 9, 2019 the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.23113 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, all payable on Dec. 31, 2019.

17. Commitments and Contingencies

A. Commitments

During the second quarter of 2019, the Corporation entered into new contractual commitments for new assets beginning in the third quarter of 2019, with total payments of $61 million. Annual payments will be: 2019 - $5 million; 2020 - $17 million; 2023 to 2038 - $2-3 million per year. In October 2019, TransAlta entered into an additional commitment to transport 150,000 GJ/day of natural gas on a firm prices for a 15 year period, beginning in 2023.

In addition, beginning on Nov. 1, 2019, TransAlta has a commitment to transport the initial daily contract quantity of 139,000 GJ/day of natural gas on a firm basis on the Pioneer Pipeline.

For other Growth project commitments, refer to Note 3 for details.

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. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required. 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.

I. Line Loss Rule Proceeding

The Corporation has been participating in a 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 Alberta Electric System Operator to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total potential retroactive exposure faced by the Corporation for its non-PPA MWs. The Corporation has recorded a provision of $15 million as at Sept. 30, 2019 (Dec. 31, 2018 - $15 million), which is expected to be reduced to $10 million upon the closing of the Keephills 3 and Genesee 3 asset swap on Oct. 1, 2019.

II. FMG Disputes

The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment 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 second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

III. Mangrove

On April 23, 2019, Mangrove Partners 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 Partners is seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations.

IV. Coalview Fatality - Regulatory Investigation

On Sept. 4, 2019, the United States Mine Safety and Health Administration ("MSHA") released its report following its investigation into the death of an employee of Coalview. MSHA cited Coalview, as mine contractor, for two violations, finding that there was an "unwarrantable failure to comply with a mandatory standard". TransAlta, however, was also cited with a single violation - failing to maintain machinery and equipment in safe operating condition, despite the fact that TransAlta did not own, operate or maintain the equipment. TransAlta is taking steps to contest the citation.

V. Keephills Force Majeure

Keephills Unit 1 was taken offline Mar. 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, the PPA Buyer at the time, did not dispute the force majeure but the Balancing Pool purported to do so. TransAlta denied that the Balancing Pool had the right to do so. Ultimately, the Balancing Pool brought and won an Originating Application confirming it has a right under the PPA to commence an arbitration, independent of the PPA Buyer. On Sept. 4, 2019 the Alberta Court of Appeal upheld the lower court's decision. The Balancing Pool is seeking to recover $12 million in capacity payment charges it paid TransAlta resulting from the force majeure declaration. An arbitration schedule has not been set.

18. Segment Disclosures

A. Reported Segment Earnings (Loss)

3 months ended Sept. 30, 2019	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	208	184	46	39	52	40	26	(2)	593
Fuel and purchased power	129	107	14	2	4	3	—	(2)	257
Gross margin	79	77	32	37	48	37	26	—	336
Operations, maintenance, and administration	34	18	11	9	12	8	5	17	114
Depreciation and amortization	53	24	11	11	34	8	—	7	148
Asset impairment (reversal) *(Note 5)*	—	(42)	—	—	—	2	—	18	(22)
Taxes, other than income taxes	3	1	—	—	2	1	—	1	8
Termination of Sundance B and C PPAs	(56)	—	—	—	—	—	—	—	(56)
Net other operating (income) loss	(10)	—	(1)	—	—	—	—	—	(11)
Operating income (loss)	55	76	11	17	—	18	21	(43)	155
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(55)
Foreign exchange loss									(9)
Other gains (losses)									(6)
Earnings (loss) before income taxes									87

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

3 months ended Sept. 30, 2018	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	232	158	54	41	55	37	18	(2)	593
Fuel and purchased power	158	122	23	2	3	2	—	(2)	308
Gross margin	74	36	31	39	52	35	18	—	285
Operations, maintenance, and administration	37	17	11	10	14	8	4	19	120
Depreciation and amortization	62	22	10	12	26	7	1	6	146
Asset impairment *(Note 5)*	38	—	—	—	—	—	—	—	38
Taxes, other than income taxes	3	1	—	—	2	1	—	—	7
Net other operating income	(10)	—	—	—	(6)	—	—	—	(16)
Operating income (loss)	(56)	(4)	10	17	16	19	13	(25)	(10)
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(73)
Foreign exchange loss									(8)
Other income									1
Earnings (loss) before income taxes									(88)

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

9 months ended Sept. 30, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**608**	**416**	**158**	**120**	**213**	**126**	**98**	**(1)**	**1,738**
Fuel, carbon, and purchased power	**426**	**295**	**57**	**6**	**11**	**6**	**—**	**(1)**	**800**
Gross margin[1]	**182**	**121**	**101**	**114**	**202**	**120**	**98**	**—**	**938**
Operations, maintenance, and administration	**102**	**50**	**33**	**27**	**37**	**26**	**22**	**51**	**348**
Depreciation and amortization	**172**	**60**	**31**	**36**	**92**	**23**	**1**	**21**	**436**
Asset impairment (reversal) *(Note 5)*	**—**	**(42)**	**—**	**—**	**—**	**2**	**—**	**18**	**(22)**
Taxes, other than income taxes	**10**	**3**	**1**	**—**	**6**	**2**	**—**	**1**	**23**
Termination of Sundance B and C PPAs	**(56)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(56)**
Net other operating (income) loss	**(30)**	**—**	**(1)**	**—**	**(4)**	**—**	**—**	**2**	**(33)**
Operating income (loss)	**(16)**	**50**	**37**	**51**	**71**	**67**	**75**	**(93)**	**242**
Finance lease income	**—**	**—**	**5**	**—**	**—**	**—**	**—**	**—**	**5**
Net interest expense									**(161)**
Foreign exchange loss									**(18)**
Other gains (losses)									**(18)**
Earnings (loss) before income taxes									**50**

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

9 months ended Sept. 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	680	296	167	123	192	127	48	(6)	1,627
Fuel, carbon, and purchased power	490	186	70	6	13	5	—	(6)	764
Gross margin[1]	190	110	97	117	179	122	48	—	863
Operations, maintenance, and administration	127	44	36	28	38	27	17	59	376
Depreciation and amortization	176	54	31	36	82	22	2	19	422
Asset impairment *(Note 5)*	38	—	—	—	12	—	—	—	50
Taxes, other than income taxes	10	3	1	—	6	3	—	—	23
Termination of Sundance B and C PPAs	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(31)	—	—	—	(6)	—	—	—	(37)
Operating income (loss)	27	9	29	53	47	70	29	(78)	186
Finance lease income	—	—	7	—	—	—	—	—	7
Net interest expense									(200)
Foreign exchange gain									(15)
Other income									1
Earnings (loss) before income taxes									(21)

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

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 Sept. 30		**9 months ended Sept. 30**	
	2019	2018	**2019**	2018
Depreciation and amortization expense on the Condensed Consolidated Statements of Earnings	**148**	146	**436**	422
Depreciation included in fuel and purchased power	**29**	34	**88**	101
Depreciation and amortization on the Condensed Consolidated Statements of Cash Flows	**177**	180	**524**	523

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 Annual Audited Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the period ended Sept. 30, 2019:

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

0.40 times

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

Supplemental Information

		Sept. 30, 2019	Dec 31, 2018
Closing market price (TSX) ($)		**8.62**	5.59
Price range for the last 12 months (TSX) ($)	High	**10.14**	7.90
	Low	**5.44**	5.44
FFO before interest to adjusted interest coverage[2](times)		**4.7**	4.8
Adjusted FFO to adjusted net debt[2](%)		**20.6**	20.8
Adjusted net debt to comparable EBITDA[1, 2] (times)		**3.6**	3.6
Deconsolidated net debt to deconsolidated comparable EBITDA [1,2] (times)		**4.2**	4.3
Adjusted net debt to invested capital[1] (%)		**49.4**	49.7
Return on equity attributable to common shareholders[2](%)		**(8.9)**	(15.8)
Return on capital employed[2](%)		**1.2**	0.7
Earnings coverage[2](times)		**0.4**	0.2
Dividend payout ratio based on FFO[1, 2](%)		**6.5**	7.6
Dividend coverage[2](times)		**16.1**	18.3
Dividend yield[2](%)		**1.9**	2.9

(1) These ratios incorporate items that are not defined under IFRS. None of these measurements should be used in isolation or as a substitute for the Corporation's reported financial performance or position as presented in accordance with IFRS. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application. For a reconciliation of the non-IFRS measures used in these calculations, refer to the Discussion of Financial Results section of this MD&A.
(2) Last 12 months. During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Ratio Formulas

FFO before interest to adjusted interest coverage = FFO + interest on debt and lease obligations - interest income - capitalized interest / interest on debt and lease obligations + 50 per cent dividends paid on preferred shares - interest income

Adjusted FFO to adjusted net debt = FFO - 50 per cent dividends paid on preferred shares / period end long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash

Adjusted net debt to comparable EBITDA = long-term debt,lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / comparable EBITDA

Deconsolidated net debt to deconsolidated comparable EBITDA = long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash - TransAlta Renewables long-term debt and lease obligations including current portion - tax equity financing / comparable EBITDA - TransAlta Renewables comparable EBITDA - TA Cogen comparable EBITDA + dividends received from TransAlta Renewables + dividends received from TA Cogen

Adjusted net debt to invested capital = long-term debt,lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / adjusted net debt + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares

Return on equity attributable to common shareholders = net earnings (loss) attributable to common shareholders / equity attributable to shareholders excluding AOCI - issued preferred shares

Return on capital employed = earnings (loss) before income taxes + net interest expense - net earnings (loss) attributable to non-controlling interests / invested capital excluding AOCI

Earnings coverage = net earnings (loss) attributable to shareholders + income taxes + net interest expense / interest on debt and lease obligations + 50 per cent dividends paid on preferred shares - interest income

Dividend payout ratio = dividends paid on common shares / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage ratio based on comparable FFO = FFO - 50 per cent dividends paid on preferred shares/ dividends paid on common shares

Dividend yield = dividend paid per common share / current period's closing market price

Glossary of Key Terms

Availability - A measure of the 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.

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

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

Gigawatt - 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) - Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

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.

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

PPA Settlements - The Balancing Pool terminated the Sundance B and C Power Purchase Arrangements and as a result, paid TransAlta $157 million in the first quarter of 2018 as well as an additional $56 million (plus GST and interest) on settlement of the dispute in the third quarter of 2019. See the Significant and Subsequent Events section for further details.

Unplanned Outage - The shut-down of a generating unit due to an unanticipated breakdown.

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