TransAlta™

TRANSALTA CORPORATION
First 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 months ended March 31, 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 March 31, 2019. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated *May 13, 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 months ended March 31, 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"), funds from operations ("FFO"), free cash flow ("FCF"), total consolidated net debt, adjusted 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; the $750 million investment by Brookfield, including the closing of the second tranche of $400 million of preferred shares, the use of proceeds, the expected benefits associated with the Brookfield investment; the share buy backs of up to $250 million; the timing of closing the investment in the Skookumchuck Wind Energy Facility; the duration of the mothballing of the Sundance Unit 3 and Sundance Unit 5; pit development work and planned power maintenance outages; cost estimates for the development of the US Wind Projects; the construction of the Pioneer Pipeline, including the timing and costs thereof; the Windrise wind project and the cost and commercial operation date thereof; WindCharger Project and this project will be the first utility-scale battery storage project in Alberta, the receipt of funds from the Emissions Reduction Alberta, the supply of lithium-ion batteries, the receipt of regulatory approvals and the construction and commercial operation dates, and expected cost; the expected benefits from Project Greenlight and embedding the program into the business and realization of new value; the expected return of capital to shareholders; that TransAlta and Brookfield will work together to complete TransAlta's transition to clean energy, maximize the value of the Hydro Assets, and create long-term shareholder value; Brookfield's increase in its share ownership to 9%; the Mangrove legal action; 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; the exposure under the Alberta Utilities Commission line loss proceeding; the FMG claims; the dispute with the Balancing Pool; the section under "2019 Financial Outlook", including the Comparable EBITDA, FCF, dividend levels, availability for our generating segments, market pricing and portfolio management strategy, fuel costs, energy marketing, liquidity and capital resources, growth expenditures, planned outages in 2019 and lost production, and 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 Company's ability to successfully defend against any existing or potential legal actions or regulatory proceedings, including by Mangrove Partners; 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; the anticipated Alberta capacity market framework in the future; our ownership of or relationship with TransAlta Renewables Inc. 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 Inc.; 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; the failure of the conditions precedent to the second tranche of the investment to be satisfied; risks associated with the calculation of the 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 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 March 31, 2019	2018
Revenues	**648**	588
Net earnings (loss) attributable to common shareholders	**(65)**	65
Cash flow from operating activities	**82**	425
Comparable EBITDA(1,2,3)	**221**	393
FFO(1,3)	**169**	318
FCF(1,3)	**95**	238
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.23)**	0.23
FFO per share(1)	**0.59**	1.10
FCF per share(1)	**0.33**	0.83
Dividends declared per common share	**—**	0.04
Dividends declared per preferred share(4)	**—**	0.26

As at	**March 31, 2019**	Dec. 31, 2018
Total assets	**9,328**	9,428
Total consolidated net debt(5)	**3,191**	3,141
Total long-term liabilities	**4,537**	4,421

(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.
(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.

Excluding the one time receipt of $157 million for the termination of the Sundance B and C Power Purchase Arrangements ("PPA") received during the first quarter of 2018, comparable EBITDA for the three months ended March 31, 2019 decreased $15 million compared to the same period in 2018. The reduction was primarily a result of the expiry of the Mississauga contract, lower revenues on the Poplar Creek contract in Canadian Gas and an unplanned outage in US Coal. The decrease was partially offset by higher market prices in Hydro, stronger performance in Energy Marketing and lower Corporate costs. Canadian Coal comparable EBITDA remained consistent with 2018, despite that in the first quarter of 2018 we operated four Sundance units under PPAs compared to operating two merchant units in 2019, as we benefited from strong merchant pricing.

Excluding the one time receipt of $157 million ($115 million after tax) for the termination of the Sundance B and C PPAs, net loss attributable to common shareholders during the first quarter of 2019 was $15 million higher due to lower comparable EBITDA, higher depreciation, and higher earnings attributable to non-controlling interests, partially offset by lower interest expense and lower income tax expense.

Year-to-date FCF, one of the Corporation's key financial metrics, after adjusting for the one time receipt for the termination of the Sundance B and C PPAs received in 2018, was $14 million higher than the same period in 2018.

- The Australian Gas, Wind and Solar, Hydro, Energy Marketing and Corporate segments generated cash flow consistent with or better than the same period last year.
- In Alberta, Canadian Coal, Hydro and our wind assets benefited from higher power prices. Average prices during the first quarter in Alberta increased to $69 per MWh from $35 per MWh, compared to the same period in 2018, mainly reflecting the impact of the extreme cold weather during February and March of 2019.
- Excluding the one time receipt for the termination of the Sundance B and C PPAs of $157 million received in 2018, Canadian Coal cash flow was $10 million lower in the first three months of 2019 compared to 2018, mainly due to higher sustaining capital spend.
- US Coal cash flow was significantly lower in the first quarter of 2019 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.

Significant Events

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

- On March 25, 2019, the Corporation announced a $750 million investment in exchangeable securities by Brookfield Renewable Partners or its affiliates (collectively "Brookfield") that 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 also accelerates the Company's plan to return capital to its shareholders. Brookfield brings its extensive hydro experience with the addition of two

new Board directors and the creation of a hydro operating committee. On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for unsecured subordinated debentures.
- 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 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, an innovative 10 MW / 20 MWh energy storage project.

See the Significant and Subsequent Events section of this MD&A for further details.

Availability and Production

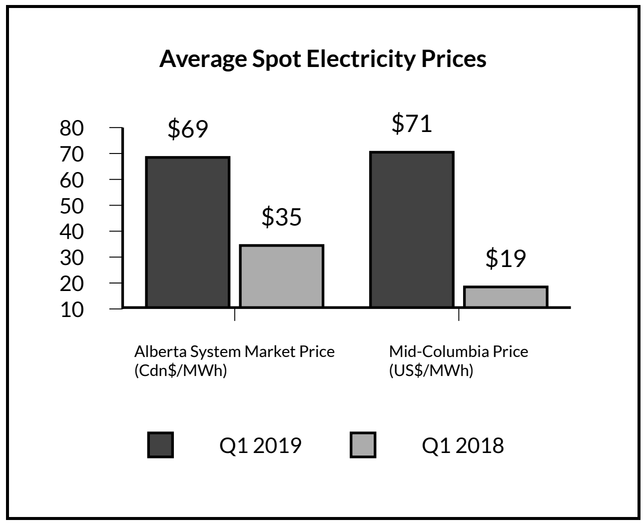
Availability for the three months ended March 31, 2019 was 89.4 per cent compared to 93.9 per cent for the same period in 2018. The decreases were mainly due to higher unplanned outages and derates at US Coal and an unplanned outage at Australian Gas.

Production for the three months ended March 31, 2019 was 8,125 gigawatt hours ("GWh") compared to 7,171 GWh for the same period in 2018. The higher production is primarily due to a strong price environment in the Pacific Northwest, which resulted in higher dispatching at US Coal. This was partially offset by lower production at Canadian Coal due to the mothballing of Sundance Units 3 and 5 on April 1, 2018.

Electricity Prices

The average spot electricity prices in Alberta for the three months ended March 31, 2019 increased significantly compared to 2018 primarily due to significantly below average temperatures in February and early March.

Power prices were substantially higher in the Pacific Northwest in the three months ended March 31, 2019, mainly due to stronger weather driven demand in February and March as well as regional daily natural gas prices that averaged approximately US$14/mmBtu in the quarter.



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 profitability. 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.

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

	3 months ended March 31(1)	
	2019	2018
Net earnings (loss) attributable to common shareholders (2)	**(65)**	65
Net earnings attributable to non-controlling interests	**35**	28
Preferred share dividends	**—**	10
Net earnings (loss)	**(30)**	103
Adjustments to reconcile net income to comparable EBITDA		
Depreciation and amortization	**145**	130
Foreign exchange loss	**1**	2
Net interest expense	**50**	68
Income tax expense	**17**	37
Comparable reclassifications		
Decrease in finance lease receivables	**6**	15
Mine depreciation included in fuel cost	**29**	31
Australian interest income	**1**	1
Unrealized gains (losses) from risk management activities	**2**	(23)
Adjustments to earnings to arrive at comparable EBITDA		
Impacts associated with Mississauga recontracting(3)	**—**	29
Comparable EBITDA	**221**	393
Comparable EBITDA - excluding the PPA settlement	**221**	236

(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.
(3) The Mississauga recontracting ended in 2018. The impact for the three months ended March 31, 2019 was a decrease to revenue of $29 million.

Excluding the one time receipt of $157 million for the termination of the Sundance B and C PPAs received during the first quarter of 2018, comparable EBITDA for the three months ended March 31, 2019 decreased $15 million compared to the same period in 2018. The reduction was primarily a result of the expiry of the Mississauga NUG Contract, lower revenues on the Poplar Creek contract in Canadian Gas and an unplanned outage in US Coal. The decrease was partially offset by higher market prices in Hydro, stronger performance in Energy Marketing and lower Corporate costs. Canadian Coal comparable EBITDA remained consistent with 2018 despite that in the first quarter of 2018 we operated four Sundance units under PPAs compared to operating two merchant units in 2019 as we benefited from strong merchant pricing.

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 March 31,	
	2019	2018
Cash flow from operating activities[1]	**82**	425
Change in non-cash operating working capital balances	**80**	(123)
Cash flow from operations before changes in working capital	**162**	302
Adjustment:		
Decrease in finance lease receivable	**6**	15
Other	**1**	1
FFO	**169**	318
Deduct:		
Sustaining capital[2]	**(25)**	(20)
Productivity capital	**(2)**	(4)
Dividends paid on preferred shares[3]	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(32)**	(41)
Payments on lease obligations[2]	**(5)**	(4)
Other	**—**	(1)
FCF	**95**	238
Weighted average number of common shares outstanding in the year	**285**	288
FFO per share	**0.59**	1.10
FCF per share	**0.33**	0.83

(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.
(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 remove finance leases from sustaining capital. 2018 results have been revised to reflect these changes.
(3) Dividends paid on preferred shares for the three months ended March 31, 2019 have been adjusted to include the April 1, 2019 payment as this relates to dividends payable in the first quarter of 2019.

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

	3 months ended March 31,	
	2019	2018
Comparable EBITDA[1]	**221**	393
Interest expense	**(42)**	(53)
Provisions	**4**	(3)
Current income tax expense	**(7)**	(9)
Realized foreign exchange gain (loss)	**(5)**	3
Decommissioning and restoration costs settled	**(7)**	(7)
Other cash and non-cash items	**5**	(6)
FFO	**169**	318
Deduct:		
Sustaining capital[2]	**(25)**	(20)
Productivity capital	**(2)**	(4)
Dividends paid on preferred shares[3]	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(32)**	(41)
Payments on lease obligations[2]	**(5)**	(4)
Other	**—**	(1)
FCF	**95**	238

(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 for the early termination of Sundance B and C PPAs.
(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 remove finance leases from sustaining capital. 2018 results have been revised to reflect these changes.
(3) Dividends paid on preferred shares for the three months ended March 31, 2019 have been adjusted to include the April 1, 2019 payment as this relates to dividends payable in the first quarter of 2019.

	3 months ended March 31,	
Supplemental disclosure	**2019**	2018
FFO - excluding the PPA settlement	**169**	161
FCF - excluding the PPA settlement	**95**	81

FFO was up $8 million over the first three months of 2018 (after adjusting for the 2018 one time receipt of $157 million for the termination of the Sundance B and C PPAs), mainly due to lower interest expense partially offset by lower Comparable EBITDA of $15 million. The increase in FCF in the first quarter of 2019 compared to the same period in 2018 was mainly due to higher FFO and lower distributions paid to subsidiaries' non-controlling interests.

Segmented Comparable Results

Segmented cash flows 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 March 31,	
	2019	2018
Segmented cash inflow (outflow)[1]		
Canadian Coal[2]	**41**	208
US Coal	**(12)**	18
Canadian Gas	**24**	60
Australian Gas	**30**	31
Wind and Solar	**66**	65
Hydro	**24**	16
Generation cash inflow	**173**	398
Energy Marketing	**24**	(18)
Corporate	**(11)**	(25)
Total comparable cash inflow	**186**	355
Total comparable cash inflow - excluding PPA settlement	**186**	198

(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.

Canadian Coal

	3 months ended March 31,	
	2019	2018
Availability (%)	**91.3**	90.5
Contract production (GWh)	**2,062**	3,300
Merchant production (GWh)	**1,657**	909
Total production (GWh)	**3,719**	4,209
Gross installed capacity (MW)(1)	**3,231**	3,231
Revenues(2)	**235**	268
Fuel, carbon costs, and purchased power(2)	**146**	165
Comparable gross margin	**89**	103
Operations, maintenance, and administration	**33**	47
Taxes, other than income taxes	**3**	3
Termination of Sundance B and C PPAs	**—**	(157)
Net other operating income	**(10)**	(11)
Comparable EBITDA(2)	**63**	221
Deduct:		
Sustaining capital:		
Routine capital	**3**	4
Mine capital	**5**	2
Planned major maintenance	**3**	—
Total sustaining capital expenditures(3)	**11**	6
Productivity capital	**2**	1
Total sustaining and productivity capital expenditures	**13**	7
Provisions	**1**	(3)
Payments on lease obligations(3)	**4**	3
Decommissioning and restoration costs settled	**4**	6
Canadian Coal cash flow	**41**	208

(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 all payments on lease obligations as a separate line in arriving at segmented cash flow.

	3 months ended March 31,	
Supplemental disclosure	**2019**	2018
Comparable EBITDA - excluding the PPA settlement	**63**	64
Canadian Coal cash flow - excluding the PPA settlement	**41**	51

Availability for the first quarter improved compared to 2018, mainly due to lower unplanned outages and derates in 2019.

Production for the three months ended March 31, 2019 decreased 490 GWh compared to the same period in 2018. Lower total production was due to the mothballing of Sundance Units 3 and 5 in April of 2018 and lower PPA dispatching due to the end of the PPAs at Sundance on April 1, 2018. Lower contract production is partially offset by lower unplanned outages and derates and higher merchant production.

Revenue for the three months ended March 31, 2019 decreased by $33 million compared to the same period in 2018, mainly due to the termination of the Sundance B and C PPAs on March 31, 2018, which resulted in lower production, partially offset by higher market prices.

In the first quarter of 2019, revenue per MWh of production was slightly lower at approximately $63 per MWh compared with $64 per MWh in 2018. Revenues in 2018 included the Sundance B and C PPA revenue as well as the pass through 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 consistent in 2019 compared to 2018.

During the first quarter we co-fired 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 with the completion of the Pioneer Pipeline in the second quarter of 2019.

OM&A costs were $14 million lower in the three months ended March 31, 2019 compared to 2018 due to cost reductions achieved in line with fewer units operating. However, there are certain fixed and common costs that are required to maintain the remaining operational Sundance units.

Excluding the one time receipt of $157 million for the termination of the Sundance B and C PPAs in the first quarter of 2018, comparable EBITDA for the three months ended March 31, 2019 was consistent with that achieved under the PPAs in the same quarter of 2018, despite the end of the Sundance PPAs and mothballing of two units. This largely reflects the combined impact of higher prices and lower OM&A costs offsetting the loss of the ability to recover Sundance carbon compliance costs.

Sustaining and productivity capital expenditures increased $5 million for the first quarter compared to the same period in 2018, as capital increased due to pit development work and planned power plant maintenance outages in 2019. There were no planned maintenance outages on operated power plants in 2018.

US Coal

	3 months ended March 31,	
	2019	2018
Availability (%)[1]	**76.9**	99.7
Contract sales (GWh)	**820**	821
Merchant sales (GWh)	**2,174**	749
Purchased power (GWh)	**(969)**	(852)
Total production (GWh)	**2,025**	718
Gross installed capacity (MW)	**1,340**	1,340
Revenues[2]	**159**	85
Fuel and purchased power	**154**	44
Comparable gross margin	**5**	41
Operations, maintenance, and administration	**14**	15
Taxes, other than income taxes	**1**	1
Comparable EBITDA[2]	**(10)**	25
Deduct:		
Sustaining capital:		
Planned major maintenance	**—**	5
Total sustaining capital expenditures[3]	**—**	5
Payments on lease obligations[3]	**—**	1
Decommissioning and restoration costs settled	**2**	1
US Coal cash flow	**(12)**	18

(1) Adjusted availability was the same as availability for the first quarter of 2019 and 2018.
(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 all 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.

Availability for the three months ended March 31, 2019 was down compared to 2018 due to higher unplanned outages and derates. In 2019, both Centralia Units remained in service for the entire first quarter 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. Availability was also lower in 2019 as Centralia Unit 1 operated with a derate due to blocked precipitator hoppers for this entire period.

Production was up 1,307 GWh during the first three months of 2019 compared to 2018, due mainly to higher merchant sales and the timing of dispatch optimization.

Comparable EBITDA was down by $35 million during the first quarter of 2019 compared to 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. This isolated and extreme pricing event was the result of cold weather and strong demand in the Pacific Northwest as well as from extremely high natural gas prices. The affected unit was able to return to service earlier than expected for delivery in the real time market, however, it was only able to recover a portion of the day ahead hedge losses due to real time prices settling significantly below the day ahead settlement price. The day ahead and subsequent real time prices are historically very similar. The event occurred within a 48 hour period. The remaining variance of $10 million is mainly related to the strong results in 2018 as we fulfilled our contracted volumes with low priced power purchases.

Sustaining and productivity capital expenditures for the three months ended March 31, 2019 decreased $5 million as there were no planned outages in 2019 due to strong market prices.

US Coal's cash flow declined by $30 million for the first quarter of 2019, compared to the same period in 2018, due mainly to lower Comparable EBITDA.

Canadian Gas

	3 months ended March 31,	
	2019	2018
Availability (%)	**99.5**	98.7
Contract production (GWh)	**437**	414
Merchant production (GWh)	**159**	39
Total production (GWh)	**596**	453
Gross installed capacity (MW)	**945**	953
Revenues(1)	**72**	104
Fuel and purchased power	**31**	29
Comparable gross margin	**41**	75
Operations, maintenance, and administration	**11**	13
Taxes, other than income taxes	**—**	1
Comparable EBITDA(1)	**30**	61
Deduct:		
Sustaining capital:		
Routine capital	**5**	1
Planned major maintenance	**1**	1
Total sustaining capital expenditures	**6**	2
Productivity capital	**—**	1
Total sustaining and productivity capital expenditures	**6**	3
Provisions and other	**—**	(2)
Canadian Gas cash flow	**24**	60

(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.

Availability for the three months ended March 31, 2019 increased compared to the same period in 2018, primarily due to lower planned outages at Sarnia.

Production for the three months ended March 31, 2019 increased 143 GWh compared to the same period in 2018, mainly due to higher production at the Sarnia facility.

Comparable EBITDA for the three months ended March 31, 2019 decreased by $31 million compared to the same period in 2018, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease. In 2018, comparable EBITDA included $29 million of revenues from the Mississauga contract.

Sustaining and productivity capital for the three months ended March 31, 2019 increased $3 million due to the timing of capital spares purchases for Sarnia.

Cash flow at Canadian Gas decreased by $36 million in the first quarter of 2019 compared to 2018, due to lower comparable EBITDA and timing of capital spend.

Australian Gas

	3 months ended March 31,	
	2019	2018
Availability (%)	**81.3**	91.7
Contract production (GWh)	**466**	440
Gross installed capacity (MW)	**450**	450
Revenues	**41**	41
Fuel and purchased power	**1**	1
Comparable gross margin	**40**	40
Operations, maintenance, and administration	**10**	9
Comparable EBITDA	**30**	31
Australian Gas cash flow	**30**	31

Availability for the three months ended March 31, 2019 decreased compared to the same period in 2018, primarily due to an unplanned outage at the South Hedland power station.

Production for the three months ended March 31, 2019 increased 26 GWh compared to the same period in 2018, mainly due to increased customer demand. Our contracts in Australia are capacity contracts, and our results are not directly impacted by increased electricity generation.

Comparable EBITDA for the three months ended March 31, 2019 was consistent with the same period in 2018, which was expected due to the nature of our contracts.

Wind and Solar

	3 months ended March 31,	
	2019	2018
Availability (%)	**95.0**	94.5
Contract production (GWh)	**757**	749
Merchant production (GWh)	**214**	279
Total production (GWh)	**971**	1,028
Gross installed capacity (MW)	**1,382**	1,363
Revenues(1)	**87**	89
Fuel and purchased power	**4**	6
Comparable gross margin	**83**	83
Operations, maintenance, and administration	**12**	13
Taxes, other than income taxes	**2**	2
Comparable EBITDA(1)	**69**	68
Deduct:		
Sustaining capital:		
Planned major maintenance	**2**	3
Total sustaining and productivity capital expenditures	**2**	3
Decommissioning and restoration costs settled	**1**	—
Wind and Solar cash flow	**66**	65

(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.

Availability was slightly better than 2018. Production for the three months ended March 31, 2019 decreased by 57 GWh compared to the same period in 2018, mainly due to lower wind resources in Western Canada and the United States, partially offset by higher wind resources in Eastern Canada.

Comparable EBITDA for the three months ended March 31, 2019 was consistent with the same period in 2018 as lower overall production was offset by favourable pricing in Alberta and reductions in operating and production-based costs.

Wind and Solar's cash flow was consistent in the first quarter of 2019, compared to the same period in 2018, due to consistent comparable EBITDA and capital expenditures.

Hydro

	3 months ended March 31,	
	2019	2018
Production		
Energy contracted		
Alberta hydro PPA assets (GWh)[1]	**318**	282
Other hydro energy (GWh)[1]	**27**	36
Energy merchant		
Other hydro energy (GWh)	**3**	5
Total energy production (GWh)	**348**	323
Ancillary services volumes (GWh)[2]	**781**	946
Gross installed capacity (MW)	**926**	926
Revenues		
Alberta hydro PPA assets energy	**29**	10
Alberta hydro PPA assets ancillary services	**29**	15
Capacity payments received under Alberta hydro PPA[3]	**14**	14
Other revenue[4]	**5**	6
Total gross revenues	**77**	45
Net payment relating to Alberta hydro PPA	**(40)**	(18)
Revenues	**37**	27
Fuel and purchased power	**1**	1
Comparable gross margin	**36**	26
Operations, maintenance, and administration	**8**	8
Taxes, other than income taxes	**1**	1
Comparable EBITDA[5]	**27**	17
Deduct:		
Sustaining capital:		
Routine capital	**1**	—
Planned major maintenance	**2**	1
Total sustaining capital expenditures	**3**	1
Hydro cash flow	**24**	16

(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.
(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 months ended March 31, 2019 increased by 25 GWh compared to the same period in 2018, primarily due to favourable market prices in Alberta, partially offset by lower water resources in British Columbia.

Total gross revenues for the first quarter of 2019 increased by $32 million compared to 2018, due to favourable power and ancillary services pricing. After net payments relating to the Alberta hydro PPA, comparable EBITDA for the three months ended March 31, 2019 increased by $10 million compared to the same period in 2018.

Hydro's cash flow improved by $8 million for the first quarter of 2019, compared to the same period in 2018, due mainly to higher Comparable EBITDA, partially offset by capital expenditures.

Energy Marketing

	3 months ended March 31,	
	2019	2018
Revenues and gross margin[1]	**28**	(2)
Operations, maintenance, and administration	**9**	8
Comparable EBITDA[1]	**19**	(10)
Deduct:		
Provisions and other	**(5)**	8
Energy Marketing cash flow	**24**	(18)

(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 March 31, 2019, comparable EBITDA was $29 million higher compared to the same period in 2018 due to strong results from US Western markets.

Energy Marketing's cash flow improved by $42 million in the first quarter of 2019, compared to the same period in 2018, due mainly to higher comparable EBITDA.

In addition, Energy Marketing generated $18 million in unrealized mark-to-market gains in the three months ended March 31, 2019 (2018 - $19 million gains), which were not included in comparable EBITDA or cash flow above. The cash flow from these mark-to-market gains is expected to be realized in future periods.

Corporate

	3 months ended March 31,	
	2019	2018
Operations, maintenance, and administration	**(7)**	(20)
Comparable EBITDA	**(7)**	(20)
Deduct:		
Sustaining capital:		
Routine capital	3	3
Total sustaining capital expenditures	**3**	**3**
Productivity capital	—	2
Total sustaining and productivity capital expenditures	**3**	5
Payments on lease obligations[1]	1	—
Corporate cash flow	**(11)**	(25)

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

During the period, operation, maintenance, and administration costs decreased by $13 million, primarily due to a realized gain from the total return swap on our share-based payment plans. 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. Excluding the impact of the realized gain on the total return swap, corporate costs were $1 million lower than the first quarter of 2018, mainly due to reduced spending on productivity capital, partially offset by higher costs on share-based payment grants and a prior year credit adjustment.

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	March 31, 2019	Dec. 31, 2018
FFO	**778**	927
Less: Early termination payment received on Sundance B and C PPAs	**—**	(157)
Add: Interest on debt and lease obligations, net of interest income and capitalized interest	**162**	174
FFO before interest	**940**	944
Interest on debt and lease obligations, net of interest income	**165**	176
Add: 50 per cent of dividends paid on preferred shares[1]	**20**	20
Adjusted interest	**185**	196
FFO before interest to adjusted interest coverage (times)	**5.1**	4.8

(1) Dividends paid on preferred shares for the three months ended March 31, 2019 have been adjusted to include the April 1, 2019 payment as this relates to dividends payable in the first quarter of 2019.

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

Adjusted FFO to Adjusted Net Debt

As at	March 31, 2019	Dec. 31, 2018
FFO[1]	**778**	927
Less: Early termination payment received on Sundance B and C PPAs[1]	**—**	(157)
Less: 50 per cent of dividends paid on preferred shares[1, 2]	**(20)**	(20)
Adjusted FFO	**758**	750
Period-end long-term debt[3]	**3,308**	3,267
Less: Cash and cash equivalents	**(109)**	(89)
Less: Principal portion of TransAlta OCP restricted cash	**—**	(27)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[4]	**(8)**	(10)
Adjusted net debt	**3,662**	3,612
Adjusted FFO to adjusted net debt (%)	**20.7**	20.8

(1) Last 12 months.
(2) Dividends paid on preferred shares for the three months ended March 31, 2019 have been adjusted to include the April 1, 2019 payment as this relates to dividends payable in the first quarter of 2019.
(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 March 31, 2019 and Dec. 31, 2018.

Our adjusted FFO to adjusted net debt remained consistent with 2018. Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent.

Adjusted Net Debt to Comparable EBITDA

As at	March 31, 2019	Dec. 31, 2018
Period-end long-term debt[1]	**3,308**	3,267
Less: Cash and cash equivalents	**(109)**	(89)
Less: Principal portion of TransAlta OCP restricted cash	**—**	(27)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[2]	**(8)**	(10)
Adjusted net debt	**3,662**	3,612
Comparable EBITDA[3, 4]	**980**	1,152
Less: Early termination payment received on Sundance B and C PPAs	**—**	(157)
Adjusted comparable EBITDA[3]	**980**	995
Adjusted net debt to comparable EBITDA[3] (times)	**3.7**	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 March 31, 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 adjusted net debt to comparable EBITDA ratio remained consistent with 2018. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times.

Strategic Growth and Corporate Transformation

Coal-to-Gas Conversions
We are planning the conversion of some or all of the units at Sundance and Keephills to gas-fired generation in the 2020 to 2022 time frame. During the first quarter of 2019, we issued Limited Notice to Proceed ("LNTP") for the coal-to-gas conversion on Sundance Unit 6 and expect to issue Full Notice to Proceed ("FNTP") for this unit during the second half of 2019. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020. Through the remainder of 2019, we expect to issue LNTP and FNTP for a number of the other Sundance and Keephills units and 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 approximately \$35 million for increasing our ability to co-fire gas and for advancing our coal-to-gas conversions.

In addition, we continue to evaluate the potential to repower one or more of the steam turbines at Sundance by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined cycle units. We expect to make the decision to proceed with this investment before the end of 2019. Repowering is expected to cost 40% lower than a new combined cycle facility while achieving a similar heat rate.

Acquisition of Two US Wind Projects
On Feb. 20, 2018, TransAlta Renewables announced that it had entered into an arrangement to acquire two wind construction-ready projects in the United States. Construction of the projects is 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 Corporation acquired the development project. Cost estimates for the US Wind Projects have been re-forecasted to \$250 million, primarily due to weather related delays. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing 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. The foundation work has been completed and the tower erection is planned for the second quarter of 2019. Both Big Level and Antrim are expected to be fully operational during the second half of 2019. See the Significant and Subsequent Events section of this MD&A for further details.

Pioneer Gas Pipeline Partnership
On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. Tidewater is constructing and will operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline is expected to provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta, including associated infrastructure, is estimated to be approximately \$100 million. Construction of the pipeline commenced in November 2018, construction is tracking to plan and the pipeline is expected to be fully operational by the second quarter of 2019.

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. The project is progressing through the permitting process and is on track to reach commercial operation during the second quarter of 2021.

WindCharger Project
During the first quarter of 2019, TransAlta approved the WindCharger Battery Storage Project ("WindCharger"), 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. Both a Sale and Purchase Agreement as well as a Services Agreement were executed with Tesla who will supply newly developed and highly efficient lithium-ion battery technology. Regulatory applications, including a facilities application to the Alberta Utilities Commission, have been submitted with approvals expected in during the third quarter of 2019. Construction is anticipated to begin in March 2020 with a commercial operation date of June 2020. The total expected cost of the project to TransAlta is US$8 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

Strategic Investment by Brookfield
On March 25, 2019, the Corporation announced it had entered into an investment agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") will invest $750 million in the Corporation. 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 also 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 will be 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 future Hydro Assets' 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.

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 Hydro Assets, and create long-term shareholder value.

TransAlta has also committed to returning up to $250 million of capital to shareholders through share repurchases within the next three years.

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. The structuring fee has been recorded as a prepaid transaction cost.

Skookumchuck Wind Energy Facility

On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW construction-ready wind facility located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with an investment grade counterparty. TransAlta will make its investment decision when the facility reaches its commercial operation date, which is expected to be in December 2019. Total consideration for the investment will represent 49 per cent of the total construction cost less capital contributions from tax equity investors.

Mothballing of Sundance Units

On March 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of the following Sundance units:

- Sundance Unit 3 will remain mothballed until Nov. 1, 2021, extended from April 1, 2020; and
- Sundance Unit 5 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

On Jan. 2, 2019, TransAlta Renewables funded $45 million (US$33 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.

Please refer to the Strategic Growth and Corporate Transformation section of this MD&A for updates on ongoing projects. Please 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 months ended March 31, 2019 for significant events impacting prior 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

Federal Carbon Pricing

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 (CO2e) emitted in 2019 and will rise by $10 per year until reaching $50 per tonne in 2022.

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.

Clean Fuel Standard

In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard to reduce Canada's greenhouse gas emissions through the increase 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 Clean Fuels Standard 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

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 Innovation and Emissions Reduction ("TIER") regime, expected to take effect on Jan. 1, 2020.

Under TIER, large emitters that emit over 100,000 tCO_2e per year will be covered. Similar to CCIR, TIER is an intensity-based carbon standard where emission obligations are assessed on a tonnes of carbon per unit of production above the set intensity standard. Electricity sector covered entities will have to meet a "good-as-best-gas" sector intensity standard that should be similar to CCIR at 370 tCO2e/MWh. 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 of $20/$tCO_2e$, 2) making reductions at their facility, 3) remitting emission performance credits from other facilities, or 4) remitting emission offset credits. The Carbon Fund payments will be used to fund emission reduction technologies in Alberta.

In addition, the UCP has committed to undertake a 90 day review of whether a capacity market or the current energy-only market is better for consumers. The process for consultation is still unclear, however, a report is expected during the third quarter of 2019.

The Corporation is monitoring these developments and other potential UCP policy changes that may affect the electricity sector.

Capital Structure and Liquidity

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

	March 31, 2019		Dec. 31, 2018	
As at	**$**	**%**	$	%
TransAlta Corporation				
Recourse debt - CAD debentures	**647**	**9**	647	9
Recourse debt - US senior notes	**930**	**13**	943	13
Credit facilities	**227**	**3**	174	2
US tax equity financing	**26**	**1**	28	—
Other	**11**	**—**	11	—
Less: Cash and cash equivalents	**(59)**	**(1)**	(16)	—
Less: Principal portion of TransAlta OCP restricted cash	**—**	**—**	(27)	—
Less: fair value asset of economic hedging instruments on debt	**(8)**	**—**	(10)	—
Net recourse debt	**1,774**	**25**	1,750	24
Non-recourse debt	**442**	**6**	469	6
Lease obligations	**62**	**1**	63	1
Total consolidated net debt - TransAlta Corporation	**2,278**	**32**	2,282	31
TransAlta Renewables				
Credit facility	**183**	**3**	165	2
Less: cash and cash equivalents	**(50)**	**(1)**	(73)	(1)
Net recourse debt	**133**	**2**	92	1
Non-recourse debt	**764**	**11**	767	11
Lease obligations	**16**	**—**	—	—
Total net debt - TransAlta Renewables	**913**	**13**	859	12
Total consolidated net debt	**3,191**	**45**	3,141	43
Non-controlling interests	**1,140**	**16**	1,137	16
Equity attributable to shareholders				
Common shares	**3,059**	**42**	3,059	42
Preferred shares	**942**	**13**	942	13
Contributed surplus, deficit, and accumulated other comprehensive income	**(1,124)**	**(16)**	(1,004)	(14)
Total capital	**7,208**	**100**	7,275	100

Overall, our total consolidated net debt increased by $50 million during the first three months of 2019 mainly due to increased drawings on the credit facilities and the recognition of additional lease obligations as required due to accounting changes (see the Accounting Changes section of this MD&A), partially offset by scheduled principal repayments on non-recourse debt. Between 2019 and 2021, we have approximately $645 million of debt maturing.

Our credit facilities provide us with significant liquidity. We have a total of $2.0 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 $0.5 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 during the second quarter of 2018 and expire in 2022, 2022, and 2020 respectively. The $1.75 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, $0.9 billion (Dec. 31, 2018 - $0.9 billion) is not drawn. At March 31, 2019, the $1.1 billion (Dec. 31, 2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $410 million (Dec. 31, 2018 - $339 million) and letters of credit of $697 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 $0.9 billion available under the credit facilities, the Corporation also has $109 million of available cash and cash equivalents.

The Corporation's subsidiaries have issued non-recourse bonds of $1,205 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 first quarter. However, funds in these entities that have accumulated since the first quarter test will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2019. At March 31, 2019, $70 million (Dec. 31, 2018 -$33 million) of cash was subject to these financial restrictions.

We have $31 million (Dec. 31, 2018 - $31 million) of restricted cash related to the Kent Hills project financing that is being held in a construction reserve account, which will be released upon certain conditions being met, which are expected to be finalized in Q2 2019. 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 March 31, 2019.

The weakening of the US dollar has decreased our long-term debt balances by $15 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:

	March 31, 2019
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**(8)**
Foreign currency economic cash flow hedges on debt	**(2)**
Economic hedges on US operations	**(4)**
Unhedged	**(1)**
Total	**(15)**

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

As at	**May 13, 2019**	**March 31, 2019**	December 31,
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**284.6**	**284.6**	287.5
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 March 31, 2019, we own 60.8 per cent (March 31, 2018 - 64.0 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 TransAlta Cogeneration L.P ("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 first quarter 2019 increased to $35 million from $28 million in the same period of 2018. Earnings were up at TransAlta Renewables in 2019 due to a favourable change in the fair value of financial assets related to its investment in the Australian business, partially offset by lower interest income and higher foreign exchange losses. Earnings from TA Cogen LP were consistent quarter to quarter.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended March 31	
	2019	2018
Interest on debt	**41**	53
Interest income	**(2)**	(3)
Capitalized interest	**(1)**	—
Loss on early redemption of US Senior Notes and Debentures	**—**	5
Interest on lease obligations	**1**	1
Credit facility and bank charges	**3**	3
Other interest	**2**	3
Accretion of provisions	**6**	6
Net interest expense	**50**	68

Interest expense decreased during the three months ended March 31, 2019 due to lower debt levels and 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.

Dividends to Shareholders

The following are the common and preferred shares dividends declared up to May 13, 2019:

	Payable date		Common dividends per share	Preferred Series dividends per share				
Declaration date	**Common Shares**	**Preferred Shares**		**A**	**B**	**C**	**E**	**G**
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 from March 31, 2019, to Dec. 31, 2018:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	20	Timing of receipts and payments
Trade and other receivables	(25)	Timing of customer receipts and seasonality of revenues.
Prepaid expenses	12	Annual property tax and insurance payments ($11 million)
Inventory	(16)	Reduced coal inventory at Canadian Coal operations
Restricted cash	(35)	Restricted cash related to the OCP bonds was used as part of the debt repayment
Property, plant, and equipment, net	(135)	Depreciation for the period ($152 million), adjustments on implementing IFRS 16 ($62 million), unfavourable change in foreign exchange rates ($15 million), partially offset by additions ($34 million), acquisition relating to Antrim ($49 million) and revisions to decommissioning and restoration costs ($14 million)
Right of use assets, net	81	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)
Risk management assets (current and long term)	(38)	Market changes, contract settlements and unfavourable foreign exchange rates, partially offset by new contracts entered into during the period
Other assets	49	Note receivable for the project development costs related to the Pioneer Pipeline and and Brookfield structuring fee ($7.5 million)
Others	(13)	
Total decrease in assets	**(100)**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(39)	Timing of payments and accruals
Dividends payable	(11)	Timing of the declaration of common share dividends
Credit facilities, long term debt, and lease obligations (including current portion)	41	Drawings on the credit facility ($71 million) and net increase in lease obligations on implementation of IFRS 16 ($15 million) were partially offset by favourable changes in foreign exchange ($15 million) and repayments of long-term debt ($29 million)
Contract liabilities	17	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	8	Actuarial losses ($27 million) partially offset by liabilities moved to contract liabilities ($15 million)
Deferred income tax liabilities	(11)	Decrease in taxable temporary differences
Risk management liabilities (current and long term)	11	Market changes, contract settlements and unfavourable foreign exchange rates, partially offset by new contracts entered into during the period
Equity attributable to shareholders	(120)	Net loss ($65 million) and other comprehensive loss ($60 million)
Non-controlling interests	3	Net earnings ($35 million) and changes in non-controlling interests in TransAlta Renewables from dividend reinvestment plan ($6 million), partially offset by distributions paid and payable ($39 million)
Others	1	
Total decrease in liabilities and equity	**(100)**	

Cash Flows

The following tables outline significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2019, compared to the three months ended March 31, 2018:

3 months ended March 31,	2019	2018	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**89**	314	(225)	
Provided by (used in):				
Operating activities	**82**	425	(343)	Lower cash flow from operations before changes in working capital ($140 million) mainly due to the 2018 one time receipt of $157 million for the termination of the Sundance Units B and C PPAs. There was also an unfavourable change in non-cash working capital ($203 million).
Investing activities	**(53)**	(53)	—	Higher note receivable related to Pioneer Pipeline project development costs ($50 million), higher additions to PP&E ($11 million) and lower receipts from finance leases ($9 million) were offset by the decrease in restricted cash related to the OCP debt ($35 million) and favourable change in non-cash investing working capital balances ($34 million)
Financing activities	**(9)**	(357)	348	Lower repayments of long-term debt ($631 million), lower dividends paid on preferred shares ($10 million) and lower distributions paid to subsidiaries' non-controlling interests ($9 million) partially offset by lower borrowings under credit facilities ($255 million) and lower realized gains on financial instruments ($50 million)
Translation of foreign currency cash	**—**	—	—	
Cash and cash equivalents, end of period	**109**	**329**	**(220)**	

Other Consolidated Analysis

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 March 31, 2019, we provided letters of credit totaling $697 million (Dec. 31, 2018 - $720 million) and cash collateral of $182 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.

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 current estimate of exposure based on known data is $15 million and therefore the Corporation has recorded a provision of $15 million as at March 31, 2019 and Dec. 31, 2018.

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. Balancing Pool Dispute
Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

IV. Mangrove
On April 23, 2019, Mangrove Partners commenced an action in the Ontario Superior Court of Justice, naming TransAlta Corporation, each incumbent member of the Board of Directors of TransAlta Corporation, and Brookfield BRP Holdings (Canada) as defendants. Mangrove Partners is seeking various remedies but primarily 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.

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 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 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 March 31, 2019, total Level III financial instruments had a net asset carrying value of $656 million (Dec. 31, 2018 - $695 million net asset). The decrease during the period is primarily due to the settlement of contracts, unfavourable foreign exchange rates, and market price changes in value of the long-term power sale contract designated as an all-in-one cash flow hedge for which changes in fair value are recognized in other comprehensive income, partially offset by new contracts entered into during the period.

2019 Financial Outlook

The following table outlines our expectation on key financial targets for 2019:

Measure	Target
Comparable EBITDA	$875 million to $975 million
FCF	$270 million to $330 million
Dividend	$0.16 per share annualized, 14 to 17 per cent payout of FCF

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 89 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 in the first quarter of 2019 due to a very cold February. Pacific Northwest power prices for 2019 are expected to be lower than 2018. While prices in the first quarter of 2019 were strong due to natural gas prices and very cold weather, we don't anticipate the natural gas supply issues that impacted regional power prices in November and December to be repeated. Ontario power prices are expected to remain consistent with 2018 prices.

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 3 per cent compared to costs incurred in 2018 mainly due to higher gas prices.

Most of our 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 objective for Energy Marketing is for the segment to contribute between $75 million to $85 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, even when including the new Brookfield debt. 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 $0.9 billion under our committed facilities and $109 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 Brookfield investment 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)	227	116	111	Q3 2019	90 MW wind project with a 15-year PPA
Antrim wind development project(3)	97	66	31	Q3 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	100	65	35	Q2 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Windrise wind development project	270	4	46	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
Coal-to-gas conversions(4)	200	—	35	2020 to 2022	Coal-to-gas conversions at Canadian Coal
Total	**894**	**251**	**258**		

(1) Represents amounts spent as of March 31, 2019.
(2) The numbers reflected above are in CAD but the actual cash spend on this project is in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD$175 million, spent to date is USD$87 million and estimated total spend in 2019 is USD$88 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 USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD$75 million, spent to date is USD$50 million and expected total spend in 2019 is USD$25 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.
(4) Does not include repowering opportunities.

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	**12**	50 — 60
Planned major maintenance	Regularly scheduled major maintenance	**8**	70 — 80
Mine capital	Capital related to mining equipment and land purchases	**5**	20 — 25
Total sustaining capital(2)		**25**	**140 — 165**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**2**	10 — 15
Total sustaining and productivity capital		**27**	**150 — 180**

(1) As at March 31, 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:

- two outages for major maintenance at Keephills Unit 1 and Sundance Unit 4 within our Canadian Coal segment that were started in the first quarter of 2019 and will be completed in the second quarter of 2019;
- one major outage in our Canadian Gas segment related to our Sarnia facility during the second quarter of 2019;
- 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	500 - 550	400 - 450	900 - 1,000	39

(1) As at March 31, 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 Brookfield investment and existing liquidity. We have access to approximately $1.0 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

A. Current Accounting Changes
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 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.

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.

	Q2 2018	Q3 2018	Q4 2018	**Q1 2019**
Revenues	446	593	622	**648**
Comparable EBITDA(1)	248	250	261	**221**
FFO	188	204	217	**169**
Net earnings (loss) attributable to common shareholders	(105)	(86)	(122)	**(65)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(2)	(0.36)	(0.30)	(0.43)	**(0.23)**

	Q2 2017	Q3 2017	Q4 2017	Q1 2018
Revenues	503	588	638	588
Comparable EBITDA(1)	243	233	275	393
FFO	187	196	219	318
Net earnings (loss) attributable to common shareholders	(18)	(27)	(145)	65
Net earnings (loss) per share attributable to common shareholders, basic and diluted(2)	(0.06)	(0.09)	(0.50)	0.23

(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:
- effects of impairment charges during the second, third and fourth quarters of 2018 and second quarter of 2017;
- recognition of the $157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018;
- a recovery of a writedown of deferred tax assets in the second quarter of 2017 and a writedown in the first quarter of 2019;
- change in income tax rates in the US in the fourth quarter of 2017;
- effects of changes in useful lives of certain Canadian Coal assets during 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 months ended March 31, 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 March 31, 2019, the end of the period covered by this report, our ICFR and DC&P were effective.

Supplemental Information

		March 31, 2019	December 31, 2018
Closing market price (TSX) ($)		**9.82**	5.59
Price range for the last 12 months (TSX) ($)	High	**10.04**	7.90
	Low	**5.44**	5.44
FFO before interest to adjusted interest coverage(2)(times)		**5.1**	4.8
Adjusted FFO to adjusted net debt(2)(%)		**20.7**	20.8
Adjusted net debt to comparable EBITDA(1, 2) (times)		**3.7**	3.7
Adjusted net debt to invested capital(1) (%)		**50.8**	49.7
Return on equity attributable to common shareholders(2)(%)		**(25.0)**	(15.8)
Return on capital employed(2)(%)		**(1.9)**	0.7
Earnings coverage(2)(times)		**(0.7)**	0.2
Dividend payout ratio based on FFO(1, 2)(%)		**6.1**	7.6
Dividend coverage(2)(times)		**10.9**	18.3
Dividend yield(2)(%)		**1.6**	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 and lease obligations including fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents

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

Adjusted net debt to invested capital = long-term debt and lease obligations including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents / 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

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2019**	2018
Revenues *(Note 4)*	**648**	588
Fuel, carbon costs, and purchased power	**366**	277
Gross margin	**282**	311
Operations, maintenance, and administration	**104**	133
Depreciation and amortization	**145**	130
Taxes, other than income taxes	**7**	8
Termination of Sundance B and C PPAs *(Note 5)*	**—**	(157)
Net other operating income	**(10)**	(11)
Operating income	**36**	208
Finance lease income	**2**	2
Net interest expense *(Note 6)*	**(50)**	(68)
Foreign exchange loss	**(1)**	(2)
Earnings (loss) before income taxes	**(13)**	140
Income tax expense *(Note 7)*	**17**	37
Net earnings (loss)	**(30)**	103
Net earnings (loss) attributable to:		
TransAlta shareholders	**(65)**	75
Non-controlling interests *(Note 8)*	**35**	28
	(30)	103
Net earnings (loss) attributable to TransAlta shareholders	**(65)**	75
Preferred share dividends *(Note 15)*	**—**	10
Net earnings (loss) attributable to common shareholders	**(65)**	65
Weighted average number of common shares outstanding in the period *(millions)*	**285**	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 14)*	**(0.23)**	0.23

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2019**	2018
Net earnings (loss)	**(30)**	103
Other comprehensive income (loss)		
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**(19)**	3
Gains on derivatives designated as cash flow hedges, net of tax[(2)]	**3**	1
Total items that will not be reclassified subsequently to net earnings	**(16)**	4
Gains (losses) on translating net assets of foreign operations, net of tax	**(21)**	33
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(3)]	**8**	(12)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(4)]	**(51)**	6
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax[(5)]	**21**	(23)
Total items that will be reclassified subsequently to net earnings	**(43)**	4
Other comprehensive income (loss)	**(59)**	8
Total comprehensive income (loss)	**(89)**	111
Total comprehensive income (loss) attributable to:		
TransAlta shareholders	**(125)**	82
Non-controlling interests *(Note 8)*	**36**	29
	(89)	111

(1) Net of income tax recovery of $7 million for the three months ended March 31, 2019 (2018 - $1 million expense).
(2) Net of income tax expense of nil for the three months ended March 31, 2019 (2018 - nil).
(3) Net of income tax expense of nil for the three months ended March 31, 2019 (2018 - $1 million recovery).
(4) Net of income tax recovery of $14 million for the three months ended March 31, 2019 (2018 - $1 million expense).
(5) Net of reclassification of income tax recovery of $6 million for the three months ended March 31, 2019 (2018 - $7 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**March 31, 2019**	Dec. 31, 2018
Cash and cash equivalents	**109**	89
Restricted cash *(Note 13)*	**31**	66
Trade and other receivables	**731**	756
Prepaid expenses	**25**	13
Risk management assets *(Notes 9 and 10)*	**139**	146
Inventory	**226**	242
	1,261	1,312
Long-term portion of finance lease receivables	**187**	191
Risk management assets *(Notes 9 and 10)*	**631**	662
Property, plant, and equipment *(Note 11)*		
Cost	**13,106**	13,202
Accumulated depreciation	**(7,077)**	(7,038)
	6,029	6,164
Right of use assets *(Note 12)*	**81**	—
Intangible assets	**372**	373
Goodwill	**464**	464
Deferred income tax assets	**20**	28
Other assets *(Note 3)*	**283**	234
Total assets	**9,328**	9,428
Accounts payable and accrued liabilities	**458**	497
Current portion of decommissioning and other provisions	**56**	70
Risk management liabilities *(Notes 9 and 10)*	**100**	90
Income taxes payable	**8**	10
Dividends payable *(Note 14)*	**47**	58
Current portion of long-term debt and lease obligations *(Note 13)*	**105**	148
	774	873
Credit facilities, long-term debt, and lease obligations *(Note 13)*	**3,203**	3,119
Decommissioning and other provisions	**403**	386
Deferred income tax liabilities	**490**	501
Risk management liabilities *(Notes 9 and 10)*	**42**	41
Contract liabilities	**104**	87
Defined benefit obligation and other long-term liabilities	**295**	287
Equity		
Common shares *(Note 14)*	**3,059**	3,059
Preferred shares *(Note 15)*	**942**	942
Contributed surplus	**12**	11
Deficit	**(1,558)**	(1,496)
Accumulated other comprehensive income	**422**	481
Equity attributable to shareholders	**2,877**	2,997
Non-controlling interests *(Note 8)*	**1,140**	1,137
Total equity	**4,017**	4,134
Total liabilities and equity	**9,328**	9,428

Commitments and contingencies *(Note 16)*

Subsequent events *(Note 3)*

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited *3 months ended March 31, 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 (loss)	**—**	**—**	**—**	**(65)**	**—**	**(65)**	**35**	**(30)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**—**	**—**	**—**	**—**	**(13)**	**(13)**	**—**	**(13)**
Net losses on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(27)**	**(27)**	**—**	**(27)**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(19)**	**(19)**	**—**	**(19)**
Intercompany fair value through OCI investments	**—**	**—**	**—**	**—**	**(1)**	**(1)**	**1**	**—**
Total comprehensive income (loss)	—	—	—	**(65)**	**(60)**	**(125)**	**36**	**(89)**
Changes in non-controlling interests in TransAlta Renewables *(Note 8)*	**—**	**—**	**—**	**—**	**1**	**1**	**6**	**7**
Effect of share-based payment plans	**—**	**—**	**1**	**—**	**—**	**1**	**—**	**1**
Distributions paid, and payable, to non-controlling interests *(Note 8)*	**—**	**—**	**—**	**—**	**—**	**—**	**(39)**	**(39)**
Balance, Mar 31, 2019	**3,059**	**942**	**12**	**(1,558)**	**422**	**2,877**	**1,140**	**4,017**

3 months ended March 31, 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	—	—	—	75	—	75	28	103
Other comprehensive income (loss):								
Net gains (losses) on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	21	21	—	21
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(16)	(16)	—	(16)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	3	3	—	3
Intercompany fair value through OCI investments	—	—	—	—	(1)	(1)	1	—
Total comprehensive income	—	—	—	75	7	82	29	111
Common share dividends	—	—	—	(11)	—	(11)	—	(11)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Shares purchased under NCIB *(Note 14)*	(4)	—	—	1	—	(3)	—	(3)
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests *(Note 8)*	—	—	—	—	—	—	(41)	(41)
Balance, March 31, 2018	3,090	942	11	(1,168)	496	3,371	1,048	4,419

See accompanying notes.

Condensed Consolidated Statements of Cash Flows
(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2019**	2018
Operating activities		
Net earnings (loss)	**(30)**	103
Depreciation and amortization *(Note 17)*	**174**	161
Accretion of provisions *(Note 6)*	**6**	6
Decommissioning and restoration costs settled	**(7)**	(7)
Deferred income tax expense (recovery) *(Note 7)*	**10**	28
Unrealized (gain) loss from risk management activities	**2**	(21)
Unrealized foreign exchange (gains) losses	**(1)**	10
Provisions	**2**	5
Other non-cash items	**6**	17
Cash flow from operations before changes in working capital	**162**	302
Change in non-cash operating working capital balances	**(80)**	123
Cash flow from operating activities	**82**	425
Investing activities		
Additions to property, plant, and equipment *(Note 11)*	**(34)**	(23)
Additions to intangibles	**(3)**	(5)
Restricted cash *(Note 13)*	**35**	—
Acquisition of renewable energy development projects *(Note 3)*	**(32)**	(30)
Note receivable to fund project development costs *(Note 3)*	**(50)**	—
Proceeds on sale of property, plant, and equipment	**1**	1
Realized losses on financial instruments	**3**	—
Decrease in finance lease receivable	**6**	15
Other	**(1)**	1
Change in non-cash investing working capital balances	**22**	(12)
Cash flow from (used in) investing activities	**(53)**	(53)
Financing activities		
Net increase (repayment) in borrowings under credit facilities *(Note 13)*	**71**	326
Repayment of long-term debt *(Note 13)*	**(29)**	(660)
Dividends paid on common shares *(Note 14)*	**(11)**	(12)
Dividends paid on preferred shares *(Note 15)*	**—**	(10)
Repurchase of common shares under NCIB *(Note 14)*	**—**	(1)
Realized gains (losses) on financial instruments	**—**	50
Distributions paid to subsidiaries' non-controlling interests *(Note 8)*	**(32)**	(41)
Decrease in lease obligations *(Note 13)*	**(5)**	(4)
Change in non-cash financing working capital balances	**(3)**	—
Other	**—**	(5)
Cash flow used in financing activities	**(9)**	(357)
Cash flow from operating, investing, and financing activities	**20**	15
Cash and cash equivalents, beginning of period	**89**	314
Cash and cash equivalents, end of period	**109**	329
Cash income taxes paid	**8**	12
Cash interest paid	**32**	37

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(A)*. 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 and Risk Committee on behalf of the Board of Directors on May 13, 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

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 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 statement of financial positions, 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.

B. 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. Strategic Investment by Brookfield

On March 25, 2019, the Corporation announced that it had entered into an investment agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which will be exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the future Hydro Assets' 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. The 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 also accelerates the Corporation's plan to return capital to its shareholders. 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 also committed to returning up to $250 million of capital to shareholders through share repurchases within the next three years.

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. The structuring fee has been recorded as a prepaid transaction cost.

B. Skookumchuck Wind Energy Facility

On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW construction-ready wind facility located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with an investment grade counterparty. TransAlta will make its investment decision when the facility reaches its commercial operation date, which is expected to be in December 2019. Total consideration for the investment will represent 49 per cent of the total construction cost less capital contributions from tax equity investors.

C. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 percent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). Tidewater Midstream and Infrastructure Ltd. ("Tidewater") is constructing and will operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline will provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately $100 million. Construction of the pipeline commenced in November 2018 and the Pioneer Pipeline is expected to be fully operational by the second quarter of 2019.

During the three months ended March 31, 2019, TransAlta invested $50 million in project development costs for the Pioneer Pipeline through a note receivable, recorded in Other Assets.

D. 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 the following Sundance units:

- Sundance Unit 3 will remain mothballed until Nov. 1, 2021, extended from April 1, 2020; and
- Sundance Unit 5 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.

E. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire 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 second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 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. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing 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 Jan. 2, 2019, TransAlta Renewables funded $45 million (US$33 million) of construction costs.

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, the Corporation 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.

F. Normal Course Issuer Bid

On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted its notice 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 4.86 per cent of issued and outstanding common shares as at March 2, 2018. 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. Common shares purchased under the NCIB are cancelled.

The period during which TransAlta was authorized to make purchases under the NCIB commenced on March 14, 2018, and ended on March 13, 2019.

During the the three months ended March 31, 2019, the Corporation purchased and cancelled nil (2018 - 374,900) common shares at an average price of nil (2018 - $6.97) per common share. See Note 14 for further details.

G. 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.

H. Balancing Pool Provides Notice to Terminate 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 is disputing the termination payment it received. The Balancing Pool excluded certain mining assets that the Corporation believes should be included in the net book value calculation for an additional termination payment of $56 million. The dispute is currently proceeding through the PPA arbitration process.

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 March 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	107	2	59	22	75	35	—	—	300
Revenue from leases	16	—	—	17	—	—	—	—	33
Revenue from derivatives	(33)	(38)	5	—	2	—	46	—	(18)
Government incentives	—	—	—	—	2	—	—	—	2
Revenue from other[(1)]	135	182	1	2	10	2	—	(1)	331
Total Revenue	**225**	**146**	**65**	**41**	**89**	**37**	**46**	**(1)**	**648**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	8	2	—	—	6	—	—	—	16
Over time	99	—	59	22	69	35	—	—	284
Total Revenue from contracts with customers	**107**	**2**	**59**	**22**	**75**	**35**	**—**	**—**	**300**

(1) Includes merchant revenue and other miscellaneous.

3 months ended March 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	204	2	56	23	65	24	—	—	374
Revenue from leases	17	—	—	17	8	1	—	—	43
Revenue from derivatives	11	64	6	—	(3)	—	17	—	95
Government incentives	—	—	—	—	5	—	—	—	5
Revenue from other(1)	37	21	—	1	11	2	—	(1)	71
Total Revenue	**269**	**87**	**62**	**41**	**86**	**27**	**17**	**(1)**	**588**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	10	2	—	—	4	—	—	—	16
Over time	194	—	56	23	61	24	—	—	358
Total Revenue from contracts with customers	**204**	**2**	**56**	**23**	**65**	**24**	**—**	**—**	**374**

(1) Includes merchant revenue and other miscellaneous.

5. Termination of Sundance B and C PPAs

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool of the termination of the Sundance B and C PPAs effective March 31, 2018, and received a termination payment of $157 million during the first quarter of 2018. See Note 3 for further details.

6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended March 31	
	2019	2018
Interest on debt	**41**	53
Interest income	**(2)**	(3)
Capitalized interest	**(1)**	—
Loss on early redemption on US Senior Notes	**—**	5
Interest on lease obligations	**1**	1
Credit facility fees and bank charges	**3**	3
Other interest and fees	**2**	3
Accretion of provisions	**6**	6
Net interest expense	**50**	68

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended March 31	
	2019	2018
Current income tax expense	**7**	9
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(9)**	24
Deferred income tax expense arising from the writedown of deferred income tax assets(1)	**19**	4
Income tax expense	**17**	37

	3 months ended March 31	
	2019	2018
Current income tax expense	**7**	9
Deferred income tax expense	**10**	28
Income tax expense	**17**	37

(1) During the three months ended March 31, 2019, the Corporation recorded a writedown of deferred income tax assets of $19 million (March 31, 2018 - $4 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 wrote these assets off as it is no longer considered probable that sufficient future taxable income will be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses.

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	**Ownership and voting rights percentage**	**Equity participation percentage**
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018(1)	61.1	61.1
July 31, 2018 to Nov. 29, 2018(2)	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018(2)	60.9	60.9
Jan. 1, 2019 to March 31, 2019(2)	60.8	60.8

(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.
(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 March 31	
	2019	2018
Net earnings		
TransAlta Cogeneration L.P.	**4**	3
TransAlta Renewables	**31**	25
	35	28
Total comprehensive income		
TransAlta Cogeneration L.P.	**4**	3
TransAlta Renewables	**32**	26
	36	29
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**15**	20
TransAlta Renewables	**17**	21
	32	41

As at	**March 31, 2019**	Dec. 31, 2018
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**164**	176
TransAlta Renewables	**976**	961
	1,140	1,137
Non-controlling interests per share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.2**	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 and regression or extrapolation formulas, 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	March 31, 2019		December 31, 2018	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**734**	+110 -184	801	+116 -116
Unit contingent power purchases	**25**	+3 -4	18	+4 -4
Structured products - Eastern US	**8**	+3 -3	6	+5 -5
Long-term wind energy sale - Eastern US	**(37)**	+19 -19	(39)	+21 -21
Others	**11**	+4 -4	9	+3 -3

i. Long-Term Power Sale - US

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

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). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at March 31, 2019 are US$20 - US$35 (Dec. 31, 2018 - US$20 - US$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 - US$10 (Dec. 31, 2018 - US$6) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2018 to March 31, 2019, the base fair value and the sensitivity values have decreased by approximately $11 million and $3 million, respectively.

ii. Unit Contingent Power Purchases

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 March 31, 2019, are nil (Dec. 31, 2018 - nil) and 2.2 per cent to 16.9 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 8.5 per cent to 27.3 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 March 31, 2019, are 88 per cent to 103 per cent and 64 per cent to 104 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 2.9 per cent to 5.1 per cent (Dec. 31, 2018 - 4 per cent to 7 per cent) and a change in non-standard shape factors of approximately 4.1 per cent to 8.6 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 March 31, 2019, are 20 per cent to 31 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 12 per cent to 24 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 second half of 2019, with the contract extending for 15 years after commercial operation. 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 March 31, 2019 are US$45-US$68 and US$7 (Dec. 31, 2018 - US$42-US$68 and US$7-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 March 31, 2019, are as follows: Level I - $1 million net asset (Dec. 31, 2018 - $3 million net asset), Level II - $32 million net liability (Dec. 31, 2018 - $19 million net liability), Level III - $656 million net asset (Dec. 31, 2018 - $695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2019 are primarily attributable to unfavourable market changes, contract settlements and unfavourable foreign exchange rates, partially offset by new contracts entered into 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 three months ended March 31, 2019 and 2018, respectively:

	3 months ended March 31, 2019			3 months ended March 31, 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	**(21)**	**3**	**(18)**	4	(19)	(15)
Market price changes on new contracts	**—**	**5**	**5**	—	1	1
Contracts settled	**(17)**	**3**	**(14)**	(22)	(25)	(47)
Change in foreign exchange rates	**(12)**	**—**	**(12)**	18	1	19
Transfers into (out of) Level III	**—**	**—**	**—**	—	(4)	(4)
Net risk management assets at end of period	**639**	**17**	**656**	719	6	725
Additional Level III information:						
Gains (losses)recognized in other comprehensive income	**(33)**	**—**	**(33)**	22	—	22
Total gains (losses) included in earnings before income taxes	**(17)**	**8**	**(9)**	22	(17)	5
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**11**	**11**	—	(42)	(42)

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 $3 million as at March 31, 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 three months ended March 31, 2019 are primarily attributable to new contracts and market changes.

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**
Long-term debt - March 31, 2019	**—**	**3,322**	**—**	**3,322**	**3,230**
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

The fair values of the Corporation's debentures and senior notes 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:

	3 months ended March 31	
	2019	2018
Unamortized net gain at beginning of period	**49**	105
New inception gain (loss)	**—**	(16)
Change in foreign exchange rates	**—**	3
Amortization recorded in net earnings during the year	**(8)**	(8)
Unamortized net gain at end of period	**41**	84

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 March 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**45**	**(4)**	**41**
Long-term	**591**	**(7)**	**584**
Net commodity risk management assets (liabilities)	**636**	**(11)**	**625**
Other			
Current	**1**	**(3)**	**(2)**
Long-term	**3**	**2**	**5**
Net other risk management assets (liabilities)	**4**	**(1)**	**3**
Total net risk management assets (liabilities)	**640**	**(12)**	**628**

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

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 March 31, 2019, associated with the Corporation's proprietary trading activities was $3 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 until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at March 31, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $16 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 March 31, 2019, associated with these transactions was $11 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, 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 March 31, 2019:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1)	89	11	**100**	**731**
Long-term finance lease receivables	100	—	**100**	**187**
Risk management assets(1)	99	1	**100**	**770**
Loan and notes receivable(2)	—	100	**100**	**102**
Total				**1,790**

(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) Includes the loan receivable of $37 million due from the Corporation's partner at Kent Hills wind farm and the note receivable for $65 million related to the Pioneer Pipeline (see Note 3). The counterparties have 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 March 31, 2019, was $17 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 March 31, 2019, TransAlta maintains investment grade ratings from three credit rating agencies and a below investment grade rating from one credit rating agency. TransAlta is focused on strengthening its financial position and maintaining or achieving investment grade credit ratings with these major rating agencies.

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

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Accounts payable and accrued liabilities	458	—	—	—	—	—	458
Long-term debt(1)	69	486	90	1,040	142	1,432	3,259
Commodity risk management liabilities	29	65	125	126	115	165	625
Other risk management (assets) liabilities	(1)	1	(2)	5	—	—	3
Lease obligations	15	17	11	6	3	26	78
Interest on long-term debt and lease obligations(2)	121	156	133	126	85	711	1,332
Dividends payable	47	—	—	—	—	—	47
Total	**738**	**725**	**357**	**1,303**	**345**	**2,334**	**5,802**

(1) Excludes impact of hedge accounting.
(2) 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 in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. 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 March 31, 2019, the Corporation had posted collateral of $105 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 if triggered could result in the Corporation having to post an additional $91 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	—	—	—	—	—	29	5	34
Acquisitions *(Note 3)*	—	—	—	—	—	50	—	50
Depreciation	—	(76)	(19)	(30)	(23)	—	(4)	(152)
Revisions and additions to decommissioning and restoration costs	—	8	1	2	3	—	—	14
Retirement of assets and (disposals)	(1)	1	—	(2)	(1)	—	(1)	(4)
Change in foreign exchange rates	—	(4)	(4)	(4)	(1)	(2)	(1)	(16)
Transfers	—	17	3	1	24	(53)	9	1
As at March 31, 2019	**93**	**2,118**	**817**	**2,088**	**452**	**224**	**237**	**6,029**

(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 transfered 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).

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
Depreciation	—	(1)	—	(3)	(4)
As at March 31, 2019	**28**	**17**	**4**	**32**	**81**

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

For the three months ended March 31, 2019, TransAlta paid $6 million related to the above leases, consisting of $1 million in interest and $5 million in principal repayments.

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 months ended March 31, 2019, the Corporation expensed $1 million in variable land lease payments for these leases.

For further information regarding leases please refer to Notes 4, 6, 10 and 13.

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

A. Amounts Outstanding

The amounts outstanding are as follows:

As at	**March 31, 2019**			**Dec. 31, 2018**		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**410**	**410**	**3.6%**	339	339	3.8%
Debentures	**647**	**651**	**5.8%**	647	651	5.8%
Senior notes(3)	**930**	**940**	**5.4%**	943	955	5.4%
Non-recourse(4)	**1,206**	**1,221**	**4.4%**	1,236	1,250	4.4%
Other(5)	**37**	**37**	**9.2%**	39	39	9.2%
	3,230	**3,259**		3,204	3,234	
Lease obligations	**78**			63		
	3,308			3,267		
Less: current portion of long-term debt	**(85)**			(130)		
Less: current portion of lease obligations	**(20)**			(18)		
Total current long-term debt and lease obligations	**(105)**			(148)		
Total credit facilities, long-term debt, and lease obligations	**3,203**			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 March 31, 2019 - US$0.7 billion (Dec. 31, 2018 - US$0.7 billion).
(4) Includes US$1 million at March 31, 2019 (Dec. 31, 2018 - US$1 million).
(5) Includes US$20 million at March 31, 2019 (Dec. 31, 2018 - US$21 million) of tax equity financing.

The Corporation has a total of $2.0 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 $0.5 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 expire in 2022, 2022 and 2020 respectively. The $1.75 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, $0.9 billion (Dec. 31, 2018 - $0.9 billion) is not drawn. At March 31, 2019, the $1.1 billion (Dec. 31, 2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $410 million (Dec. 31, 2018 - $339 million) and letters of credit of $697 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 $0.9 billion available under the credit facilities, the Corporation also has $109 million of available cash and cash equivalents.

The Corporation's total outstanding letters of credit as at March 31, 2019 were $697 million (Dec. 31, 2018 - $720 million), including TransAlta Renewables outstanding letters of credit of $75 million (Dec. 31, 2018 - $77 million) with no (Dec. 31, 2018 - nil) amounts exercised by third parties under these arrangements. The Corporation and TransAlta Renewables both have 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 March 31, 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 $1,205 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 first quarter. However, funds in these entities that have accumulated since the first quarter test will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2019. At March 31, 2019, $70 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 March 31, 2019.

C. Security

Non-recourse debts of $764 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 certain renewable generation facilities with total carrying amounts of $1,006 million at March 31, 2019 (Dec. 31, 2018 - $1,021 million). At March 31, 2019, a non-recourse bond of approximately $127 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 $314 million at March 31, 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 $31 million (Dec. 31, 2018 - $31 million) of restricted cash related to the Kent Hills project financing which is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in the second quarter of 2019.

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

14. Common Shares

A. Issued and Outstanding

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

	3 months ended March 31			
	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[1]	**—**	**—**	(0.4)	(4)
Issued and outstanding, end of period	**284.6**	**3,059**	287.5	3,090

(1) 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. During the three months ended March 31, 2018 374,900 common shares were repurchased at a total cost of $3 million.

B. Earnings per Share

	3 months ended March 31	
	2019	2018
Net earnings (loss) attributable to common shareholders	**(65)**	65
Basic and diluted weighted average number of common shareholders outstanding (millions)	**285**	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.23)**	0.23

C. Dividends

On Dec. 14, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on April 1, 2019.

On April 15, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on July 1, 2019.

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

D. Stock Options

The stock options granted to executive officers of the Corporation during the three months ended March 31, 2019 and 2018 are as follows:

Grant month	**Number of stock options granted** *(millions)*	**Exercise price**	**Vesting period** *(years)*	**Expiration length** *(years)*
January 2019	1.3	$ 5.59	3	7
January 2018	0.7	$ 7.45	3	7

15. 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.

As at March 31, 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 months ended March 31:

		3 months ended March 31	
Series	**Quarterly amounts per share**	**2019(1)**	2018
A	0.16931	—	2
B	0.23073(2)	—	—
C	0.25169	—	3
E	0.32463	—	3
G	0.33125	—	2
Total for period		—	10

(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 $nil dividends were declared for the three months ended March 31, 2019.

On April 15, 2019 the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.23136 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 $0.33125 per share on the Series G preferred shares, all payable on June 30, 2019.

16. Commitments and Contingencies

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

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 current estimate of exposure based on known data is $15 million and therefore the Corporation has recorded a provision of $15 million as at March 31, 2019 and Dec. 31, 2018.

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. Balancing Pool Dispute

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

IV. Mangrove
On April 23, 2019, Mangrove Partners commenced an action in the Ontario Superior Court of Justice, naming TransAlta Corporation, each incumbent member of the Board of Directors of TransAlta Corporation, and Brookfield BRP Holdings (Canada) as defendants. Mangrove Partners is seeking various remedies but primarily 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.

17. Segment Disclosures

A. Reported Segment Earnings (Loss)

3 months ended March 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	225	146	65	41	89	37	46	(1)	648
Fuel, carbon, and purchased power	175	154	31	2	4	1	—	(1)	366
Gross margin(1)	50	(8)	34	39	85	36	46	—	282
Operations, maintenance, and administration	33	14	11	10	12	8	9	7	104
Depreciation and amortization	61	18	10	11	29	8	1	7	145
Taxes, other than income taxes	3	1	—	—	2	1	—	—	7
Net other operating income	(10)	—	—	—	—	—	—	—	(10)
Operating income (loss)	(37)	(41)	13	18	42	19	36	(14)	36
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(50)
Foreign exchange loss									(1)
Earnings before income taxes									(13)

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

3 months ended March 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	269	87	62	41	86	27	17	(1)	588
Fuel, carbon, and purchased power	196	44	29	2	6	1	—	(1)	277
Gross margin(1)	73	43	33	39	80	26	17	—	311
Operations, maintenance, and administration	47	15	13	9	13	8	8	20	133
Depreciation and amortization	50	16	11	12	27	8	—	6	130
Taxes, other than income taxes	3	1	1	—	2	1	—	—	8
Termination of Sundance B and C PPAs	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(11)	—	—	—	—	—	—	—	(11)
Operating income (loss)	141	11	8	18	38	9	9	(26)	208
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(68)
Foreign exchange gain									(2)
Earnings before income taxes									140

(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 March 31	
	2019	2018
Depreciation and amortization expense on the Condensed Consolidated Statements of Earnings	**145**	130
Depreciation included in fuel and purchased power	**29**	31
Depreciation and amortization on the Condensed Consolidated Statements of Cash Flows	**174**	161

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 March 31, 2019:

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

(0.71) 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.

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.

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.

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

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