TRANSALTA CORPORATION
Third Quarter Report for 2018

Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2018 and 2017, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2017 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 condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") *34 Interim Financial Reporting* for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Sept. 30, 2018. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated *Oct. 30, 2018*. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov**, and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income in our Condensed Consolidated Statements of Earnings (Loss) for the three and nine months ended Sept. 30, 2018 and 2017. 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 EBITDA, FFO, comparable FFO, FCF, net debt, adjusted net debt and cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Reconciliation of Non-IFRS Measures and Discussion of Segmented Comparable Results sections of this MD&A for additional information.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are presented for general information purposes only and not as specific investment advice. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "project", "estimate", "forecast", "foresee", "potential", "enable", "continue", or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to: our business model and anticipated future financial performance; our success in executing on our growth projects; the timing and cost of the construction and commissioning of projects under development [including the Brazeau Hydro pumped storage project,] the Pennsylvania and New Hampshire wind projects, and their attendant costs and sources of funding; the closing of the New Hampshire acquisition and satisfaction of closing conditions; [the benefits of the Brazeau Hydro Pumped Storage project;] the pre-tax savings to be delivered by Project Greenlight; spending on growth and sustaining capital and productivity projects, including in connection with Project Greenlight; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; purchases of shares under the Normal Course Issue Bid ("NCIB"); continuing the deleveraging plan; regulatory developments, including the Federal Government's release of regulations for gas-fired generation; the ruling by the Alberta Utilities Commission ("AUC") in respect of line losses including our estimated maximum exposure; the section titled "2018 Financial Outlook"; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2018 comparable earnings before interest, depreciation and amortization ("EBITDA"), funds from operations ("FFO") and free cash flow ("FCF"), and expected sustaining capital expenditures; Canadian Coal Fleet availability and capacity factor; contributions to gross margin for Energy Marketing in 2018; significant planned major outages in 2018 and lost production; expected governmental regulatory regimes and legislation, including the Government of Alberta's intended shift to a capacity market and the expected impacts on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; expectations in respect of generation availability, capacity, and production; power prices in Alberta, Ontario, and the Pacific Northwest; expected financing of our capital expenditures; the anticipated financial impact of increased carbon prices, including under the Carbon Competitiveness Incentive Regulation ("CCIR") in Alberta; our trading strategies and the risk involved in these strategies; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar, the Australian dollar, and other currencies in which we do business; our exposure to liquidity risk; expectations in respect of the global economic environment; expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of TransAlta Renewables; the refinancing of our upcoming debt maturities over the next two years; expectations regarding our de-leveraging strategy; expectations in respect of our community initiatives; impacts of future IFRS standards and the timing of the implementation of such standards; and amendments or interpretations by accounting standard setters prior to initial adoption of those standards.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; ability to compete effectively in the anticipated Alberta capacity market; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; growth, whether through acquisition or greenfield development; unanticipated operating conditions; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, sun, or wind required to operate our facilities; natural or man-made disasters; physical risks related to climate change; the threat of terrorism and cyberattacks and our ability to manage such attacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing and the ability to access financing at a reasonable cost and on reasonable terms; our ability to fund our growth projects; our ability to maintain our investment grade credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; outcomes of legal, regulatory, and contractual proceedings involving the Corporation including those with Fortescue Metals Group Ltd. ("FMG"); outcomes of investigations and disputes; reliance on key personnel; labour relations matters; risks associated with development projects and acquisitions, including delays or changes in costs in the construction and commissioning of our two new US wind projects; and the maintenance or adoption of enabling regulatory frameworks or the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives, including as it pertains to coal-to-gas conversions.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our MD&A for our 2017 annual consolidated financial statements and under the heading "Risk Factors" in our 2018 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. 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 events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Revenues	**593**	588	**1,627**	1,669
Net loss attributable to common shareholders	**(86)**	(27)	**(126)**	(45)
Cash flow from operating activities	**159**	201	**688**	545
Comparable EBITDA[1, 2]	**249**	245	**890**	787
FFO[1, 2]	**204**	196	**710**	585
FCF[1, 2]	**94**	101	**426**	227
Net loss per share attributable to common shareholders, basic and diluted	**(0.30)**	(0.09)	**(0.44)**	(0.16)
FFO per share[1, 2]	**0.71**	0.68	**2.47**	2.03
FCF per share[1, 2]	**0.33**	0.35	**1.48**	0.79
Dividends declared per common share	**0.04**	0.04	**0.12**	0.08

As at	**Sept. 30, 2018**	Dec. 31, 2017
Total assets	**9,421**	10,304
Total consolidated net debt[3]	**3,057**	3,363
Total long-term liabilities	**4,345**	4,311

(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 fourth quarter of 2017, we revised our approach to reporting adjustments to arrive at FFO, mainly to better represent FFO as a cash metric. Previously, FFO was adjusted to include, exclude, or to modify the timing of cash impacts related to adjustments made in arriving at comparable EBITDA. As a result, comparable EBITDA, FFO, and FCF for 2017 has been revised accordingly.
(3) Total consolidated net debt includes long-term debt including current portion, amounts due under credit facilities, tax equity, and finance lease obligations, net of available cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure section of this MD&A for more details on the composition of net debt.

Comparable EBITDA was up $4 million in the third quarter of 2018 compared to 2017, due to:
- Higher EBITDA in Canadian Gas, Wind and Solar, and Hydro was partially offset by lower EBITDA in Canadian Coal, US Coal, and Australian Gas.
- Canadian Coal EBITDA was lower due to higher carbon compliance costs and the 2017 results include the capacity payments for Sundance Units B and C. The PPAs for Sundance Units B and C were subsequently terminated, for which the Corporation received a one-time payment in the first quarter of 2018.

Year-to-date Comparable EBITDA was higher by $103 million, primarily as a result of the one time receipt of $157 million for the termination of the Sundance Units B and C PPAs and higher EBITDA from Hydro.

Net loss attributable to common shareholders during the third quarter of 2018 was lower by $59 million compared to the same period in 2017, due to lower operating income resulting from higher mine depreciation included in fuel and purchased power, higher carbon compliance costs, an impairment related to the retirement of Sundance Unit 2, lower finance lease income related to the sale of the Solomon facility and higher income tax recovery. Net loss attributable to common shareholders during the nine months of the year was lower by $81 million compared to the same period in 2017, due to higher operating income (including the one time receipt of $157 million for the termination of the Sundance B and C PPAs), partially offset by higher mine depreciation included in fuel and purchased power, higher carbon compliance costs, an impairment, lower finance lease income related to the sale of the Solomon facility and higher income tax expense.

Year-to-date FCF, one of the Corporation's key financial metrics, was $199 million higher than 2017 and after adjusting for the one-time receipt for the termination of Sundance B and C PPAs, FCF was $42 million higher than the same period in 2017. For the third quarter, FCF was $7 million lower compared to the same period in 2017.
- All generation segments, except Australian Gas, generated cash flows equal to or better than the same period last year on a year-to-date basis. On a quarterly basis, the Canadian Gas, Wind and Solar, Hydro and Energy Marketing segments generated cash flows equal to 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 third quarter in Alberta increased to $55 per MWh from $25 per MWh and to $49 per MWh from $22 per MWh in the first nine months of 2018, compared to the same periods in 2017, mainly reflecting the impact of higher carbon pricing costs paid by certain generators and load growth.
- Canadian Coal cash flows were significantly higher in the first nine months of 2018 compared to 2017 as the cash flows in the first quarter included the one-time receipt for the termination of the Sundance B and C PPAs, which reflects the receipt of the capacity payments that would have been received over the 2018 to 2020 period had these PPAs not been terminated.
- Sustaining capital was lower in 2018 relative to 2017, primarily because of lower capital requirements in Canadian Coal as a result of the retirement of Sundance Units 1 and 2 and the mothballing of Sundance Units 3 and 5, and lower capital requirements in Canadian Gas and US Coal, mainly due to timing of outages.
- Based on the outlook for the balance of the year, the Corporation is currently tracking to achieve the upper end of its FCF guidance of $300 - $350 million, net of the one time Sundance B and C PPAs termination payment of $157 million.

Segmented Cash Flow Generated by the Business

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 Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Segmented cash inflow (outflow)				
Canadian Coal(1)	**32**	54	**264**	164
US Coal	**11**	19	**42**	18
Canadian Gas(2)	**55**	51	**169**	165
Australian Gas	**30**	40	**92**	100
Wind and Solar	**30**	22	**143**	128
Hydro	**22**	13	**85**	51
Generation cash inflow	**180**	199	**795**	626
Energy Marketing	**32**	14	**23**	24
Corporate	**(25)**	(24)	**(73)**	(80)
Total comparable cash inflow	**187**	189	**745**	570

(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) Includes $34 million (TransAlta's share) from the OEFC relating to the settlement in the first quarter of 2018 of a prior years indexation dispute during 2017.

Significant Events

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

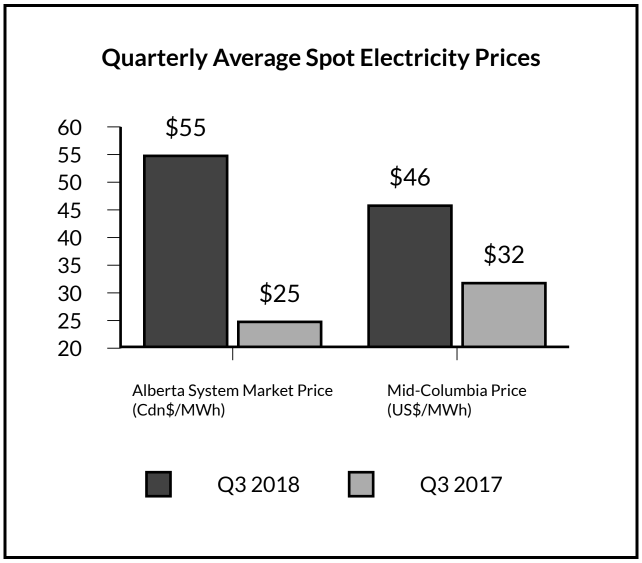
- On Oct. 19, 2018, TransAlta Renewables announced that the 17.25MW expansion of the wind facility at Kent Hills, New Brunswick, is now fully operational, bringing total generating capacity at the site to 167MW.
- On Aug. 2, 2018, the Corporation redeemed all of the outstanding principal $400 million, 6.40 per cent debentures, due Nov. 18, 2019 for approximately $425 million, including a prepayment premium and accrued and unpaid interest. See the Significant and Subsequent Events section of this MD&A for further details.
- On July 20, 2018, the Corporation monetized the payments under the Off-Coal Agreement ("OCA") with the Government of Alberta and closed an approximate $345 million bond offering at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. See the Significant and Subsequent Events section of this MD&A for further details.
- On July 31, 2018, the Sundance Unit 2 was retired. See the Significant and Subsequent Events section of this MD&A for further details.
- On May 31, 2018, TransAlta Renewables acquired an economic interest in the 50 MW Lakeswind Wind Farm and 21 MW of solar projects located in the US ("Mass Solar") from TransAlta and acquired ownership of the 20 MW Kent Breeze Wind Farm located in Ontario. The total purchase price for the three assets was approximately $166 million, including the assumption of $62 million of tax equity obligations and project debt. On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million (US $25 million) of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar in order to fund the repayment of Mass Solar's project debt.
- On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters. The shares were issued at a price of $12.65 per share for gross proceeds of approximately $150 million.
- On Feb. 20, 2018, TransAlta Renewables entered into an arrangement to acquire two construction-ready wind projects in the Northeast United States. The wind development projects consist of: (i) a 90 Megawatt ("MW") project located in Pennsylvania which 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 April 20, 2018, TransAlta Renewables acquired an economic interest in the Big Level project. The Corporation expects the acquisition to close in early 2019. See the Significant and Subsequent Events section of this MD&A for further details.
- On March 15, 2018, the Corporation redeemed the outstanding 6.650 per cent US $500 million Senior Notes due May 15, 2018. The redemption price for the Notes was approximately $617 million (US$516 million). Repayment of the US Senior notes was funded by cash on hand and our credit facility. See the Significant and Subsequent Events section of this MD&A for further details.
- During the first nine months of the year, the Corporation purchased and cancelled 1,907,200 common shares at an average price of $7.34 per common share through our NCIB program, for a total cost of $14 million. See the Significant and Subsequent Events section of this MD&A for further details.
- On March 31, 2018, the Corporation received approximately $157 million in compensation for the termination of the Sundance B and C PPAs from the Balancing Pool. See the Significant and Subsequent Events section of this MD&A for further details.
- On Jan. 1, 2018, the Corporation permanently shutdown Sundance Unit 1 and mothballed Sundance Unit 2. On April 1, 2018, we mothballed Sundance Unit 3 and Sundance Unit 5.

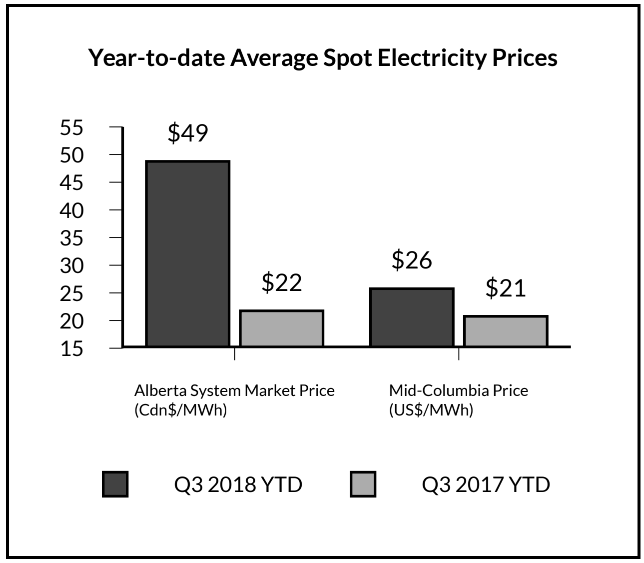
Adjusted Availability and Production
Adjusted availability for the three and nine months ended Sept. 30, 2018 was 93.7 per cent and 91.3 per cent, respectively, compared to 86.5 per cent and 86.3 per cent for the same periods in 2017. The increases were mainly due to lower unplanned and planned outages and stronger performance at Canadian Coal and Canadian Gas.

Production for the three and nine months ended Sept. 30, 2018 was 7,762 gigawatt hours ("GWh") and 20,133 GWh, respectively, compared to 9,767 GWh and 26,526 GWh for the same periods in 2017. The lower production is primarily due to certain Sundance units becoming merchant effective April 1, 2018, which resulted is less dispatching. In addition, production is down as a result of retiring and mothballing units during the year.

Electricity Prices
The average spot electricity prices in Alberta for the three and nine months ended Sept. 30, 2018 increased significantly compared to 2017 mainly due to higher carbon compliance costs, which have increased the marginal cost of production, and weather-adjusted load growth in 2018 of approximately 3 per cent.

Power prices were higher in the Pacific Northwest in the three and nine months ended Sept. 30, 2018, mainly due to stronger weather driven demand in the region as well as in California, which receives excess power from the Pacific Northwest.





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 and Australia are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We 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 new NUG Contract, we receive 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 record the payments we receive as revenues as a proxy for operating income, and continue to depreciate the facility until Dec. 31, 2018; and

(iv) On commissioning the South Hedland Power Station, 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.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017(1)	**2018**	2017(1)
Net loss attributable to common shareholders	**(86)**	(27)	**(126)**	(45)
Net earnings attributable to non-controlling interests	**9**	(21)	**65**	23
Preferred share dividends	**10**	10	**30**	20
Net earnings (loss)	**(67)**	(38)	**(31)**	(2)
Adjustments to reconcile net income to comparable EBITDA				
Depreciation and amortization	**146**	158	**422**	455
Foreign exchange (gain) loss	**8**	8	**15**	7
Other (income) loss	**(1)**	1	**(1)**	(1)
Net interest expense	**73**	69	**200**	190
Income tax expense (recovery)	**(21)**	(5)	**10**	(41)
Comparable reclassifications				
Decrease in finance lease receivables	**15**	14	**44**	44
Mine depreciation included in fuel cost	**35**	19	**103**	55
Australian interest income	**1**	1	**3**	1
Adjustments to earnings to arrive at comparable EBITDA				
Impacts to revenue associated with certain de-designated and economic hedges	**—**	—	**—**	2
Impacts associated with Mississauga recontracting(2)	**22**	18	**75**	57
Asset impairment charge	**38**	—	**50**	20
Comparable EBITDA	**249**	245	**890**	787

(1) During the fourth quarter of 2017, we revised the way in which comparable EBITDA is reconciled to net earnings. Accordingly, 2017 results have been revised.
(2) Impacts associated with Mississauga recontracting for the nine months ended Sept. 30, 2018, are as follows: revenue $78 million (2017 - $72 million), fuel and purchased power and de-designated hedges $3 million (2017 - $12 million), and operations, maintenance, and administration nil (2017 - $3 million).

Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends, or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Cash flow from operating activities	**159**	201	**688**	545
Change in non-cash operating working capital balances	**29**	(21)	**(25)**	(7)
Cash flow from operations before changes in working capital	**188**	180	**663**	538
Adjustment:				
Decrease in finance lease receivable	**15**	14	**44**	44
Other	**1**	2	**3**	3
FFO	**204**	196	**710**	585
Deduct:				
Sustaining capital	**(49)**	(40)	**(112)**	(173)
Productivity capital	**(6)**	(6)	**(12)**	(15)
Dividends paid on preferred shares[(1)]	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(43)**	(38)	**(126)**	(136)
Other	**(2)**	(1)	**(4)**	(4)
FCF	**94**	101	**426**	227
Weighted average number of common shares outstanding in the year	**287**	288	**287**	288
FFO per share	**0.71**	0.68	**2.47**	2.03
FCF per share	**0.33**	0.35	**1.48**	0.79

(1) Dividends paid on preferred shares for the three months ended Sept. 30, 2018 have been adjusted to exclude the July 3, 2018 payment as this was reflected in the second quarter FCF.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Comparable EBITDA	**249**	245	**890**	787
Interest expense	**(45)**	(56)	**(147)**	(166)
Provisions	**2**	3	**7**	3
Unrealized gains (losses) from risk management activities	**1**	(8)	**(5)**	(20)
Current income tax (expense) recovery	**1**	(5)	**(18)**	(17)
Realized foreign exchange gain (loss)	**(2)**	5	**4**	7
Decommissioning and restoration costs settled	**(10)**	(5)	**(23)**	(12)
Other cash and non-cash items	**8**	17	**2**	3
FFO	**204**	196	**710**	585
Deduct:				
Sustaining capital	**(49)**	(40)	**(112)**	(173)
Productivity capital	**(6)**	(6)	**(12)**	(15)
Dividends paid on preferred shares	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(43)**	(38)	**(126)**	(136)
Other	**(2)**	(1)	**(4)**	(4)
FCF	**94**	101	**426**	227

(1) Dividends paid on preferred shares for the three months ended Sept. 30, 2018 have been adjusted to exclude the July 3, 2018 payment as this was reflected in the second quarter FCF.

FFO for the quarter increased by $8 million over last year mainly due to increased Comparable EBITDA. FFO was down $32 million over the first nine months of 2018 (after adjusting for the one time receipt of $157 million for the termination of the Sundance B and C PPAs), mainly due to lower Comparable EBITDA of $54 million and higher mine reclamation costs, partially offset by lower interest expense and lower unrealized mark-to-mark losses.

The decrease in FCF in the third quarter of 2018 compared to the same period in 2017 was mainly due to increased sustaining capital expenditures resulting from higher mine capital expenditures at Canadian Coal. FCF increased for the year-to-date period of 2018 compared to the same period in 2017 due to lower sustaining capital expenditures resulting from lower planned maintenance activities at Canadian Coal and Canadian Gas, the timing of maintenance activities at US Coal, and lower distributions paid to subsidiaries' non-controlling interests. The increase in FCF in the year-to-date period of 2018 was also positively impacted by the Sundance B and C PPAs termination payment of $157 million received during the first quarter of 2018.

Segmented Comparable Results

Canadian Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Availability (%)	**94.4**	78.6	**91.9**	82.2
Contract production (GWh)	**1,897**	4,665	**6,855**	14,065
Merchant production (GWh)	**1,519**	918	**3,693**	2,841
Total production (GWh)	**3,416**	5,583	**10,548**	16,906
Gross installed capacity (MW)(1)	**2,457**	3,791	**2,457**	3,791
Revenues	**232**	252	**680**	750
Fuel, carbon costs, and purchased power	**123**	135	**387**	379
Comparable gross margin	**109**	117	**293**	371
Operations, maintenance, and administration	**37**	42	**127**	133
Taxes, other than income taxes	**3**	3	**10**	10
Net other operating income	**(10)**	(10)	**(188)**	(30)
Comparable EBITDA	**79**	82	**344**	258
Deduct:				
Sustaining capital:				
Routine capital	**5**	5	**12**	15
Mine capital	**21**	3	**32**	9
Finance leases	**4**	4	**11**	10
Planned major maintenance	**3**	8	**4**	43
Total sustaining capital expenditures	**33**	20	**59**	77
Productivity capital	**4**	2	**7**	7
Total sustaining and productivity capital expenditures	**37**	22	**66**	84
Provisions	**(1)**	(1)	**(3)**	(2)
Unrealized gains (losses) on risk management activities	**6**	4	**3**	6
Decommissioning and restoration costs settled	**5**	3	**14**	6
Canadian Coal cash flow	**32**	54	**264**	164

(1) On Jan. 1, 2018, 560 MW Sundance Units 1 and 2 were shut down and mothballed, respectively. On April 1, 2018, 774 MW Sundance Units 3 and 5 were mothballed. On July 31, 2018 Sundance Unit 2 was shutdown permanently.

Availability for the third quarter and year-to-date periods improved compared to 2017, mainly due to lower unplanned outages and derates in 2018. Availability in the third quarter of 2017 was impacted by coal supply disruptions at the mine.

Production for the three and nine months ended Sept. 30, 2018 decreased 2,167 GWh and 6,358 GWh, respectively, compared to the same periods in 2017. Lower production was due to the retirement and mothballing of certain Sundance units and less dispatching, partially offset by lower planned outages and derates.

Revenue for the three and nine months ended Sept. 30, 2018 decreased by $20 million and $70 million, respectively, compared to the same periods in 2017, mainly due to lower production offset by higher prices.

In the third quarter and year-to-date periods of 2018, revenue per MWh of production rose to approximately $68 per MWh from $45 per MWh in 2017 and $64 per MWh from $44 per MWh in 2017, respectively, which more than offset the increase in carbon costs and resulted in higher gross margin per MWh in both periods of 2018.

Fuel, carbon compliance costs, and purchased power costs per MWh were higher in 2018 compared to 2017. Coal costs were higher due to higher mining costs. Pit development work underway at the Highvale mine is expected to result in lower cost coal in late 2018 and future years. Carbon compliance costs were higher in 2018, reflecting the regulated increase in the carbon price and due to the fact that carbon compliance costs are no longer recoverable on the Sundance units as the PPAs have been terminated. Both the fuel and carbon pricing cost increases were as expected.

During the third quarter we continued to co-fire with natural gas at the merchant units. 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 this level of co-firing to be sustainable for the balance of 2018 and beyond.

OM&A costs were lower in both the third quarter and nine months ended Sept. 30, 2018 compared to 2017. There are certain fixed and common costs that are required to maintain the remaining operational Sundance units and during the first nine months of the year, one-time OM&A costs were incurred in association with mothballing of certain Sundance Units. We expect to see the full OM&A cost benefits from the retirement and mothballing of Sundance units reflected through the balance of 2018, as initial mothball implementation costs are non-recurring and we continue to optimize the operations of the facility in response to the merchant market.

Comparable EBITDA for the nine months ended Sept. 30, 2018 was higher by $86 million, as a result of the one time receipt of $157 million for the termination of the Sundance B and C PPAs in the first quarter of 2018, partially offset by higher carbon compliance costs. For the three months ended Sept. 30, 2018, Comparable EBITDA was consistent with the 2017 results.

Sustaining and productivity capital expenditures increased $15 million for the third quarter compared to the same period in 2017, as mine capital increased due to pit development work. Sustaining and productivity capital expenditures decreased $18 million for the nine months ended Sept. 30, 2018 compared to the same period in 2017, mainly due to lower planned outages, mothballing of units, partially offset by pit development work. Establishing pits will provide the lowest cost fuel for the remaining life of the facilities. In 2017, three planned outages were performed throughout the year, while during 2018 there were no planned major outages at TransAlta operated plants. Overall, for 2018, there are four fewer units in the fleet to maintain, which significantly reduced the sustaining capital costs.

US Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Availability (%)	**90.2**	95.7	**51.8**	56.6
Adjusted availability (%)(1)	**90.2**	95.7	**84.5**	83.2
Contract sales (GWh)	**839**	894	**2,490**	2,714
Merchant sales (GWh)	**2,400**	2,013	**3,239**	2,973
Purchased power (GWh)	**(954)**	(672)	**(2,642)**	(2,639)
Total production (GWh)	**2,285**	2,235	**3,087**	3,048
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**158**	147	**296**	296
Fuel and purchased power	**122**	109	**186**	188
Comparable gross margin	**36**	38	**110**	108
Operations, maintenance, and administration	**17**	13	**44**	37
Taxes, other than income taxes	**1**	1	**3**	3
Comparable EBITDA	**18**	24	**63**	68
Deduct:				
Sustaining capital:				
Routine capital	**—**	—	**2**	2
Finance leases	**1**	1	**3**	3
Planned major maintenance	**—**	1	**11**	28
Total sustaining capital expenditures	**1**	2	**16**	33
Productivity capital	**—**	—	**—**	3
Total sustaining and productivity capital expenditures	**1**	2	**16**	36
Unrealized gains (losses) on risk management activities	**1**	1	**(4)**	8
Decommissioning and restoration costs settled	**5**	2	**9**	6
US Coal cash flow	**11**	19	**42**	18

(1) Adjusted for economic dispatching.

Availability for the three months ended Sept. 30, 2018 was down compared to 2017 due to higher unplanned outages and derates. Availability for the nine months ended Sept. 30, 2018 was down compared to 2017 due to the timing of economic dispatching and unplanned outages and derates in the third quarter of 2018, slightly offset by forced outages on Centralia Unit 1 in January 2017. In 2017 and 2018, both Centralia Units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In 2017, we performed major maintenance on both units during that time.

Production for the third quarter of 2018 compared to 2017 was up 50 GWh due to higher merchant sales. Production was up 39 GWh during the first nine months of 2018 compared to 2017, due mainly to higher merchant sales and the timing of economic dispatching.

Comparable EBITDA was down by $6 million and $5 million during the third quarter and first nine months of 2018 compared to 2017, primarily due to lower production as a result of an unplanned outage, sales for which had to be supplied through open market purchases at higher prices.

Sustaining and productivity capital expenditures for the three and nine months ended Sept. 30, 2018 decreased $1 million and $20 million respectively, due to planned outages executed during the second quarter of 2017. Productivity capital relates to project Greenlight, our Corporate transformation project, which is intended to provide long-term cost savings. See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

US Coal's cash flows declined by $8 million for the third quarter of 2018, compared to the same period in 2017, due mainly to higher cash settlements of mine decommissioning and restoration costs and lower Comparable EBITDA. Cash flows improved by $24 million for the year-to-date 2018 period, compared to the same period in 2017, due mainly to lower sustaining and productivity capital spend, partially offset by the unfavourable impact of mark-to-market positions.

Canadian Gas

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2018	2017	**2018**	2017
Availability (%)	**95.1**	87.3	**92.8**	90.2
Contract production (GWh)	**431**	357	**1,172**	1,128
Merchant production (GWh)	**61**	98	**132**	148
Total production (GWh)	**492**	455	**1,304**	1,276
Gross installed capacity (MW)	**953**	953	**953**	953
Revenues	**95**	94	**296**	331
Fuel and purchased power	**25**	28	**73**	90
Comparable gross margin	**70**	66	**223**	241
Operations, maintenance, and administration	**11**	10	**36**	39
Taxes, other than income taxes	**—**	—	**1**	1
Net other operating income	**—**	—	**—**	—
Comparable EBITDA	**59**	56	**186**	201
Deduct:				
Sustaining capital:				
Routine capital	**—**	—	**2**	4
Planned major maintenance	**2**	3	**9**	22
Total sustaining capital expenditures	**2**	3	**11**	26
Productivity capital	**1**	—	**2**	—
Total sustaining and productivity capital expenditures	**3**	3	**13**	26
Provisions	**—**	—	**(2)**	2
Unrealized gains (losses) on risk management activities	**1**	2	**6**	8
Canadian Gas cash flow	**55**	51	**169**	165

Availability for the three months ended Sept. 30, 2018 increased compared to the same period in 2017, primarily due to lower unplanned outages at Sarnia. Availability for the nine months ended Sept. 30, 2018 increased compared to the same period in 2017, mainly due to the 2017 base cycling conversion project at Windsor and lower planned and unplanned outages at Sarnia and Windsor this year.

Production for the three and nine months ended Sept. 30, 2018 increased 37 GWh and 28 GWh, respectively, compared to the same periods in 2017, mainly due to higher production at the Fort Saskatchewan, Ottawa, and Windsor facilities.

Comparable EBITDA for the three months ended Sept. 30, 2018 increased by $3 million compared to the same period in 2017, mainly due to the positive impact from the Mississauga recontracting. For the nine months ended Sept. 30, 2018 comparable EBITDA decreased by $15 million compared to the same period in 2017, mainly due to the retroactive contract indexation dispute settlement received in 2017 ($34 million) offset by the positive impact from the Mississauga recontracting and cost reduction initiatives. The Mississauga, Ottawa, Windsor, and our 60 per cent share of Fort Saskatchewan, generating facilities are owned through our 50.01 per cent interest in TransAlta Cogeneration L.P. The Mississauga recontracting ends in December 2018 and is not expected to be renewed.

Sustaining and productivity capital for the nine months ended Sept. 30, 2018 decreased $13 million. In the second quarter of 2018 we completed a planned major maintenance at Sarnia. In 2017, we completed the base cycling conversion project at Windsor to increase its flexibility to respond to market prices and the scheduled maintenance at Sarnia.

Cash flow at Canadian Gas improved by $4 million in the third quarter of 2018 compared to 2017, due to higher Comparable EBITDA. Cash flow improved by $4 million in the nine months ended Sept. 30, 2018 compared to the prior year due to cost reduction initiatives and lower sustaining capital spend in 2018. In 2017, one-time sustaining capital expenditures were incurred for the Windsor base cycling conversion project.

Australian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Availability (%)	**98.0**	96.2	**94.6**	93.6
Contract production (GWh)	**444**	476	**1,357**	1,346
Gross installed capacity (MW)	**450**	575	**450**	575
Revenues	**41**	56	**123**	138
Fuel and purchased power	**1**	2	**3**	8
Comparable gross margin	**40**	54	**120**	130
Operations, maintenance, and administration	**10**	9	**28**	22
Comparable EBITDA	**30**	45	**92**	108
Deduct:				
Sustaining capital:				
Routine capital	**—**	5	**—**	7
Planned major maintenance	**—**	—	**—**	1
Total sustaining capital expenditures	**—**	5	**—**	8
Australian Gas cash flow	**30**	40	**92**	100

Production for the three and nine months ended Sept. 30, 2018 decreased by 32 GWh and increased by 11 GWh, respectively, due largely to the availability of the South Hedland Power Station, partially offset by FMG's repurchase of the Solomon Power Station. Our contracts in Australia are capacity contracts, and our results are not directly impacted by generation.

Comparable EBITDA for both the three and nine months ended Sept. 30, 2018 was lower than the same periods in 2017. Higher Comparable EBITDA from the South Hedland Power Station was more than offset by FMG's repurchase of the Solomon Power Station and higher OM&A costs due to the addition of the South Hedland Power Station and ongoing legal costs.

Sustaining capital for both the three and nine months ended Sept. 30, 2018 was lower than the same periods in 2017 due to major maintenance incurred at our Southern Cross facility in August 2017.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Availability (%)	**93.9**	94.6	**94.9**	95.9
Contract production (GWh)	**388**	334	**1,666**	1,598
Merchant production (GWh)	**137**	163	**639**	730
Total production (GWh)	**525**	497	**2,305**	2,328
Gross installed capacity (MW)	**1,363**	1,363	**1,363**	1,363
Revenues	**55**	42	**192**	188
Fuel and purchased power	**3**	2	**13**	10
Comparable gross margin	**52**	40	**179**	178
Operations, maintenance, and administration	**14**	12	**38**	36
Taxes, other than income taxes	**2**	2	**6**	6
Net other operating income	**(6)**	—	**(6)**	—
Comparable EBITDA	**42**	26	**141**	136
Deduct:				
Sustaining capital:				
Routine capital	**3**	1	**3**	1
Planned major maintenance	**1**	3	**5**	8
Total sustaining capital expenditures	**4**	4	**8**	9
Productivity capital	**—**	1	**—**	1
Total sustaining and productivity capital expenditures	**4**	5	**8**	10
Provisions	**—**	(2)	**—**	(2)
Unrealized gains (losses) on risk management activities	**8**	1	**(10)**	—
Wind and Solar cash flow	**30**	22	**143**	128

Production for the three months ended Sept. 30, 2018 increased by 28 GWh compared to the same period in 2017, mainly due to higher wind resources in Eastern Canada and the United States, partially offset by lower wind resources in Alberta. Production for the nine months ended Sept. 30, 2018 decreased by 23 GWh compared to the same periods in 2017, mainly due to lower wind resources across the Canadian fleet combined with the sale of the Wintering Hills merchant facility on March 1, 2017. This lower production was partially offset by higher wind resources in Eastern Canada and the United States.

Comparable EBITDA for the three months ended Sept. 30, 2018 increased by $16 million compared to the same period in 2017, primarily due to the favourable impact of the US non-cash mark-to-market gains, insurance proceeds related to a tower fire at the Wyoming Wind Farm in 2017, and higher merchant prices in Alberta. Comparable EBITDA for the nine months ended Sept. 30, 2018 increased by $5 million compared to the same period in 2017, as higher merchant prices in Alberta and insurance proceeds from Wyoming Wind Farm in 2017 were partially offset by the unfavourable impact of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract.

Wind and Solar's cash flows improved by $8 million for the third quarter of 2018, compared to the same period in 2017, due mainly to higher Comparable EBITDA, which was partially offset by the favourable impact of the US non-cash mark-to-market gains. Cash flows improved by $15 million for the year-to-date 2018 period, compared to the same period in 2017, due mainly to higher Comparable EBITDA and the addback of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Contract production (GWh)	**559**	482	**1,459**	1,544
Merchant production (GWh)	**41**	39	**73**	78
Total production (GWh)	**600**	521	**1,532**	1,622
Gross installed capacity (MW)	**926**	926	**926**	926
Revenues	**37**	31	**127**	95
Fuel and purchased power	**2**	2	**5**	5
Comparable gross margin	**35**	29	**122**	90
Operations, maintenance, and administration	**8**	10	**27**	27
Taxes, other than income taxes	**1**	—	**3**	2
Comparable EBITDA	**26**	19	**92**	61
Deduct:				
Sustaining capital:				
Routine capital	**1**	3	**2**	6
Planned major maintenance	**3**	1	**5**	3
Total sustaining capital expenditures	**4**	4	**7**	9
Productivity capital	**—**	1	**—**	1
Total sustaining and productivity capital expenditures	**4**	5	**7**	10
Unrealized gains (losses) on risk management activities	**—**	1	**—**	—
Hydro cash flow	**22**	13	**85**	51

Production for the three months ended Sept. 30, 2018 increased by 79 GWh compared to the same period in 2017, primarily due to higher water resources. Production for the nine months ended Sept. 30, 2018 decreased by 90 GWh compared to the same periods in 2017, primarily due to lower water resources.

Comparable EBITDA for the three months ended Sept. 30, 2018 increased by $7 million compared to the same period in 2017, primarily due to higher production and revenue from Ancillary Services at higher market prices. Comparable EBITDA for the nine months ended Sept. 30, 2018 increased by $31 million compared to the same period in 2017, primarily due to higher revenue from Ancillary Services at higher market prices, which more than offset the lower generation.

Hydro's cash flows improved by $9 million for the third quarter of 2018, compared to the same period in 2017, due mainly to higher Comparable EBITDA. Cash flows improved by $34 million for the year-to-date 2018 period, compared to the same period in 2017, due mainly to higher Comparable EBITDA and lower sustaining and productivity capital expenditures.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Revenues and gross margin	**18**	17	**48**	36
Operations, maintenance, and administration	**4**	5	**17**	16
Comparable EBITDA	**14**	12	**31**	20
Deduct:				
Provisions	**(1)**	(1)	**(2)**	(2)
Unrealized gains (losses) on risk management activities	**(17)**	(1)	**10**	(2)
Energy Marketing cash flow	**32**	14	**23**	24

For the three and nine months ended Sept. 30, 2018, comparable EBITDA was higher compared to the same periods in 2017 due to strong results from Western markets. Year to date 2018 results were also positively impacted by a return to normal levels during the first quarter of 2018 and negatively impacted by less favourable market dynamics in the second quarter.

Energy Marketing's cash flows improved by $18 million for the third quarter of 2018, compared to the same period in 2017, due mainly to higher Comparable EBITDA and the addback of the non-cash mark-to-market losses. Cash flows for the year-to-date 2018 period were flat, compared to the same period in 2017, as higher Comparable EBITDA in 2018 was offset by higher non-cash mark-to-market gains.

Corporate

Our Corporate overhead costs of $19 million for the third quarter of 2018 were comparable to the same period in 2017. For the first nine months of 2018, Corporate overhead costs of $59 million were $6 million lower compared to the same period in 2017 due to lower incentive payments and cost reduction initiatives.

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 by 2018.

FFO Before Interest to Adjusted Interest Coverage

As at	Sept. 30, 2018	Dec. 31, 2017
FFO(1)	929	804
Less: Early termination payment received on Sundance B and C PPAs	(157)	—
Add: Interest on debt and finance leases, net of interest income and capitalized interest	187	205
FFO before interest	**959**	1,009
Interest on debt and finance leases, net of interest income	187	214
Add: 50 per cent of dividends paid on preferred shares	20	20
Adjusted interest	**207**	234
FFO before interest to adjusted interest coverage (times)	**4.6**	4.3

(1) Last 12 months. Our target range for FFO in 2018 is $750 million to $800 million. See the 2018 Financial Outlook for further details.

While both periods are within our target range, the ratio improved at Sept. 30, 2018 compared to 2017, mainly due to lower adjusted interest. Our target for FFO before interest to adjusted interest coverage is four to five times, and we expect this metric to improve as we continue to execute on our deleveraging plan.

Adjusted Funds from Operations to Adjusted Net Debt

As at	Sept. 30, 2018	Dec. 31, 2017
FFO(1,2)	929	804
Less: Early termination payment received on Sundance B and C PPAs	(157)	—
Less: 50 per cent of dividends paid on preferred shares	(20)	(20)
Adjusted FFO	**752**	784
Period-end long-term debt(3)	3,183	3,707
Less: Cash, cash equivalents and principal portion of TransAlta OCP restricted cash	(122)	(314)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt(4)	(4)	(30)
Adjusted net debt	**3,528**	3,834
Adjusted FFO to adjusted net debt (%)	**21.3**	20.4

(1) Last 12 months.
(2) Our target range for FFO in 2018 is $750 million to $800 million. See the 2018 Financial Outlook for further details.
(3) Includes finance lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2018 and Dec. 31, 2017.

Our adjusted FFO to adjusted net debt improved compared to 2017, mainly due to lower adjusted net debt at Sept. 30, 2018. We expect this metric to improve towards our targeted level of 20 to 25 per cent as we continue to execute on our deleveraging plan.

Adjusted Net Debt to Comparable EBITDA

As at	Sept. 30, 2018	Dec. 31, 2017
Period-end long-term debt[1]	**3,183**	3,707
Less: Cash, cash equivalents and principal portion of TransAlta OCP restricted cash	**(122)**	(314)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[2]	**(4)**	(30)
Adjusted net debt	**3,528**	3,834
Comparable EBITDA[3]	**1,165**	1,062
Less: Early termination payment received on Sundance B and C PPAs	**(157)**	—
Adjusted comparable EBITDA	**1,008**	1,062
Adjusted net debt to comparable EBITDA (times)	**3.5**	3.6

(1) Includes finance lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2018 and Dec. 31, 2017.
(3) Last 12 months.

Our adjusted net debt to comparable EBITDA ratio improved compared with 2017, mainly due to the significant reduction in our net debt during the period. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times.

Strategic Growth and Corporate Transformation

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 has started. The wind development projects consist of: (i) a 90 Megawatt ("MW") project located in Pennsylvania which 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. The acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the acquisition to close in early 2019. See the Significant and Subsequent Events section of this MD&A for further details.

Kent Hills Wind Project
During 2017, TransAlta Renewables entered into a 17-year power purchase agreement with the New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind project. On Oct. 19, 2018, TransAlta Renewables announced that the expansion is fully operational, bringing total generating capacity of the Kent Hills wind facility to167 MW.

Brazeau Hydro Pumped Storage
The Brazeau Hydro Pumped Storage project will generate and support clean electricity in the Province of Alberta. It will store water that can be used to both generate power when it is needed and store excess power supply when demand is low. The Brazeau Hydro Pumped Storage project is a focus for us, as it has existing infrastructure that reduces the cost and environmental footprint of the project, is situated close to existing transmission infrastructure, and allows for increased renewables development by balancing intermittent generation from wind and solar.

We are currently working to secure a path that will advance our investment in the project and secure a long-term contract for the project. The Brazeau Hydro Pumped Storage project is expected to have new capacity up to 900 MW, bringing the total Brazeau facility from 755 to 1,255 MW, post-completion. We estimate an investment in the range of $1.5 billion to $2.7 billion. During the first nine months of 2018, we invested approximately $2 million to advance the environmental study, work with stakeholders and execute geotechnical work to help further our design and construction phase. Further advancement of the project is dependent on securing a long-term contract.

In May 2018, the AESO released a report stating that dispatchable renewable resources are not needed in the Alberta market before 2030. The value and benefit of the Brazeau Hydro Pumped Storage project would be well beyond the 2030 period. The Corporation still believes that generation from pumped storage should be part of future calls for power under the Alberta Renewables program. The Corporation is not spending additional development dollars on the project at this time but will continue to work with governments to find the appropriate financial mechanisms for bringing low cost, green, dispatchable renewables into the market to support low prices and emissions for Alberta customers.

Project Greenlight
Our transformation project is a top priority for us. Driven by engagement from all employees, the intent is to deliver ambitious improvements in every part of the Corporation. Initiatives include increasing revenue, improving generation, reducing operating and maintenance costs, reducing overhead costs and financing costs, and optimizing our capital spend. We expect Project Greenlight to deliver sustainable pre-tax savings of approximately $50 million to $70 million annually in 2018. We are on track to achieve our

expected annual savings targets. Year-to-date, we have invested approximately $10 million in this program, with these the costs largely offset by cost reductions and productivity gains. We expect to invest a further $2 million on this program for the remainder of 2018 and also expect to spend $20 million to $25 million related to productivity capital in 2018.

The following table outlines our generation comparable OM&A, including greenlight costs:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Generation comparable OM&A	**97**	96	**300**	294
Greenlight transformation costs included in OM&A				
Canadian Coal	**—**	(4)	**(5)**	(7)
US Coal	**—**	(1)	**(1)**	(1)
Gas and Renewables	**—**	(3)	**(4)**	(3)
Australia	**—**	(1)	**—**	(1)
Adjusted Generation comparable OM&A	**97**	87	**290**	282

Significant and Subsequent Events

A. TransAlta Renewables Expansion of the Kent Hills Wind Facility

On Oct. 19, 2018 TransAlta Renewables announced that the 17.25MW expansion of the wind facility at Kent Hills, New Brunswick, is now fully operational, bringing total generating capacity at the site to 167MW. In 2017, TransAlta Renewables entered into a 17-year power purchase agreement with NB Power for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind project.

B. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

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

C. TransAlta Renewables Closes $150 million Offering of Common Shares

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

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

TransAlta did not purchase any additional common shares under the Offering and, following the closing, owns 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables.

D. $345 Million Financing

The Corporation monetized the payments under the OCA on July 20, 2018, upon the closing of an approximate $345 million bond offering its indirect wholly-owned subsidiary, TransAlta OCP by way of private placement which is secured by, among other things, a first ranking charge over the OCA payments payable by the Government of Alberta. The amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The bonds have a rating of BBB, with a Stable trend, by DBRS. Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

E. Early Redemption of $400 Million of Debentures

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

F. Sundance Unit 2 Retirement

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

G. TSX Acceptance of Normal Course Issuer Bid

On March 9, 2018 we announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares ("Common Shares"). Pursuant to the NCIB, we 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. Any Common Shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018 and ends on March 13, 2019 or such earlier date on which the maximum number of Common Shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 102,039 Common Shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 Common Shares for the six months ended February 28, 2018) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the nine months ended Sept. 30, 2018, the Corporation purchased and cancelled 1,907,200 Common Shares at an average price of $7.34 per Common Share, for a total cost of $14 million. See Note 13 of the condensed consolidated financial statements for further details.

Further transactions under the NCIB will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

H. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US Senior Notes due May 15, 2018. The redemption price for the Notes was approximately $617 million (US$516 million), including $14 million of accrued interest. An early redemption premium was recognized in net interest expense for the three months ended March 31, 2018.

I. Balancing Pool Terminates the Alberta Sundance Power Purchase Arrangements

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

Pursuant to a written agreement, the Balancing Pool paid us approximately $157 million on March 29, 2018. We are disputing the termination payment received. The Balancing Pool excluded certain mining assets that we believe 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.

J. 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 Big Level project that has a 15-year PPA with Microsoft Corp., and (ii) a 29 MW Antrim project with two 20-year PPAs, 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 the 90 MW project on Feb. 20, 2018, whereas the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the acquisition to close in early 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an initial economic interest in the US wind projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary will own the US wind projects directly and TA Power will issue to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US wind projects. The construction and acquisition costs of the two US wind projects are to be funded by TransAlta Renewables and are estimated to be US$240 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 subsidiary. The proceeds from the issuance of such preferred shares or notes shall 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.

During the nine months ended Sept. 30, 2018, TransAlta Renewables funded approximately $61 million (US$48 million) of construction costs.

Regulatory Updates

Refer to the Regional Regulation and Compliance discussion in our 2017 annual MD&A for further details that supplement the recent developments as discussed below:

Canadian Federal Government

On Feb. 17, 2018, the Department of Environment and Climate Change Canada published the draft regulations for gas-fired electricity generation, which include specific rules for coal-to-gas converted units. Under the proposed regulations, TransAlta's units are expected to receive an additional 75 years of operating life as a result of being able to convert to gas-fired generation. Consultation on the draft regulations concluded in mid-2018 with finalized regulations expected by the end of 2018.

The federal government remains committed to achieving nation-wide carbon pricing as of Jan. 1, 2019. The enabling legislation through the Greenhouse Gas Pollution Pricing Act came into force on June 21, 2018. Provinces and territories were required to submit carbon pricing plans by Sept. 1, 2018 for equivalency analysis against the federal benchmark ($20/tCO2e in 2019, escalating by $10/ year to $50/tCO2e by 2022). On Oct. 23, 2018, the federal government announced the results of their equivalency review and have confirmed that Ontario will fall under the federal system as of Jan. 1, 2019. System design will include a carbon tax for small emitters and an Output Based Pricing System ("OBPS") for emission intensive trade exposed ("EITE") industrial emitters. Final sector standards have not yet been announced, but electricity generation is planned to fall within the OBPS program.

Alberta

On Jan. 1, 2018, the Alberta government transitioned from Specified Gas Emitters Regulation ("SGER") to the Carbon Competitiveness Incentive Regulation ("CCIR"). Under the CCIR, regulatory compliance moved from a facility-specific compliance standard to a product/sectoral performance compliance standard. The carbon price remains set at $30/tCO_2e$ from 2018 to 2020. On Aug. 30, 2018 Alberta announced plans to withdraw from the Pan-Canadian Framework agreement, removing the commitment to further pricing increases of $40/tCO2e in 2021 and $50/tCO2e in 2022. The electricity sector performance standard was set at $0.37tCO_2e/MWh$ declining at 1% per year from 2020 forward with a program review in 2022. Renewable assets that received crediting under the SGER are expected to continue to receive credits under CCIR on a one-to-one basis. Renewable assets that did not receive credits under SGER will now be able to opt into the CCIR and get carbon crediting up to the electricity sector performance standard. Once the wind projects crediting standard under SGER ends, these renewable projects will also be able to opt into the CCIR and receive crediting.

Ontario

On June 7, 2018, the Progressive Conservative Party was elected as the new provincial government. On July 3, 2018, the government revoked Ontario's cap-and-trade program and other green initiatives that were funded by carbon-pricing. As of Oct. 1, natural gas utilities are no longer allowed to include carbon costs in natural gas rates. Impacts of these changes to TransAlta were minimal given that contract provisions with customers provide for carbon costs flow through. Due to the cancellation of the Ontario cap-and-trade program, emitters in the province will be required to comply with the federal carbon tax program as of Jan. 1, 2019. There is expected to be limited impact to TransAlta due to TransAlta's customer contract structures in Ontario.

On July 13, 2018, the Ontario government announced the cancellation of 758 pre-notice to proceed renewable energy contracts. This decision fulfilled a campaign pledge made by the PC party to withdraw from contracts in the pre-construction phase as they could be cancelled with minimal cost impacts. One post-notice to proceed contract was cancelled for the White Pines Wind Farm. This cancellation was viewed as an anomaly as notice to proceed was issued during the writ period. Further contract cancellations are not expected at this time. TransAlta was not impacted by this decision.

Capital Structure and Liquidity

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

	Sept. 30, 2018		Dec. 31, 2017	
As at	**$**	**%**	**$**	**%**
TransAlta Corporation				
Recourse debt - CAD debentures	**647**	**9**	1,046	14
Recourse debt - US senior notes	**902**	**12**	1,499	19
Credit facilities	**132**	**2**	—	—
US tax equity financing	**27**	**—**	31	—
Other	**12**	**—**	13	—
Less: Cash, cash equivalents and principal portion of OCP restricted cash	**(98)**	**(1)**	(294)	(4)
Less: fair value asset of economic hedging instruments on debt	**(4)**	**—**	(30)	—
Net recourse debt	**1,618**	**22**	2,265	29
Non-recourse debt	**489**	**7**	208	3
Finance lease obligations	**59**	**1**	69	1
Total net debt - TransAlta Corporation	**2,166**	**30**	2,542	33
TransAlta Renewables				
Credit facility	**126**	**2**	27	—
Less: cash and cash equivalents	**(24)**	**—**	(20)	—
Net recourse debt	**102**	**2**	7	—
Non-recourse debt	**789**	**11**	814	11
Total net debt - TransAlta Renewables	**891**	**13**	821	11
Total consolidated net debt	**3,057**	**43**	3,363	44
Non-controlling interests	**1,119**	**15**	1,059	14
Equity attributable to shareholders				
Common shares	**3,074**	**42**	3,094	40
Preferred shares	**942**	**12**	942	12
Contributed surplus, deficit, and accumulated other comprehensive income	**(851)**	**(12)**	(710)	(9)
Total capital	**7,341**	**100**	7,748	100

During the nine months ended Sept. 30, 2018, we have reduced our senior corporate debt by approximately $1.0 billion and enhanced shareholder value by:

- early redeeming our outstanding 6.650 per cent US$500 million Senior Notes due May 15, 2018, for approximately $617 million (US$516 million) using proceeds from the Sundance B and C PPAs termination payment and existing liquidity.
- early redeeming our outstanding 6.40 per cent $400 million debenture due November 2019, for approximately $425 million. See the Significant and Subsequent Events section of this MD&A for further details.
- purchased and cancelled 1,907,200 Common Shares at an average price of $7.34 under our NCIB program, for a total cost of $14 million. See the Significant and Subsequent Events section of this MD&A for further details.

On June 27, 2018, the Corporation paid out US$25 million non-recourse debt related to its Mass Solar projects.

On July 20, 2018, we monetized the payments under the OCA upon closing of a $345 million bond offering through our indirect wholly-owned subsidiary, TransAlta OCP by way of private placement. The amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The net proceeds of the bond offering were used to pay for the Aug. 2, 2018 early redemption of the Corporation's outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a prepayment premium and accrued and unpaid interest.

Overall, our total consolidated net debt was reduced by approximately $300 million during the first nine months of 2018.

During the period through Dec. 31, 2021, we have approximately $719 million of debt maturing. We expect to continue our de-leveraging strategy by allocating a portion of our free cash flow over the next three years to debt reduction.

Our credit facilities provide us with significant liquidity. We have a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, comprised of our $1.3 billion committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $0.5 billion (Dec. 31, 2017 - $0.5 billion) and our $0.2 billion committed bilateral facilities. During the second quarter of 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million. These facilities were renewed during the second quarter and expire in 2022, 2022, and 2020 respectively. The $1.8 billion (Dec. 31, 2017 - $1.5 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business.

In total, $1.1 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At Sept. 30, 2018, the $0.9 billion (Dec. 31, 2017 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (Dec. 31, 2017 - $27 million) and letters of credit of $0.6 billion (Dec. 31, 2017 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.1 billion available under the credit facilities, the Corporation also has $0.1 billion of available cash and cash equivalents.

The Corporation's subsidiaries have issued non-recourse bonds of $1,277 million (Dec. 31, 2017 - $1,021 million) that are subject to customary financing conditions and covenants that may restrict our ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2018. At Sept. 30, 2018, $40 million (Dec. 31, 2017 -$35 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. We have elected to use letters of credit as at Sept. 30, 2018. In addition, we have $31 million (Dec. 31, 2017 - $30 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, including commissioning, being met. We also have $35 million (Dec. 31, 2017 - nil) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2019.

The strengthening of the US dollar has increased our long-term debt balances by $33 million in 2018. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

	Sept. 30, 2018
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**18**
Foreign currency economic cash flow hedges on debt	**5**
Economic hedges on US operations	**9**
Unhedged	**1**
Total	**33**

Share Capital

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

As at	**October 30,**	Sept. 30, 2018	December 31,
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**286.0**	**286.0**	287.9
Preferred shares			
Series A	**10.2**	10.2	10.2
Series B	**1.8**	1.8	1.8
Series C	**11.0**	11.0	11.0
Series E	**9.0**	9.0	9.0
Series G	**6.6**	6.6	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests
As of Sept. 30, 2018, we own 61.0 per cent (Dec. 31, 2017 – 64.0 per cent) of TransAlta Renewables. We remain committed to maintaining our position as the majority shareholder and sponsor of TransAlta Renewables with a stated goal of maintaining our interest between 60 to 80 per cent. On May 31, 2018, TransAlta Renewables adopted a Dividend Reinvestment Plan ("DRIP"), with the first issuance of shares being made on July 31, 2018. The participation of shareholders in TransAlta Renewables' DRIP has not had a material dilutive impact on our ownership.

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 year-to-date and third quarter 2018 periods increased to $65 million and $9 million, respectively, from $23 million and a loss of $21 million, respectively, in the same periods of 2017. Earnings in both periods were up at TransAlta Renewables in 2018 due to higher finance income from its investment in the Australian business, lower foreign exchange losses in the third quarter of 2018, and lower interest expense in the year-to-date 2018 period, partially offset by a prior period impairment of an investment. Earnings from TA Cogen LP were consistent quarter to quarter, but were lower in the year-to-date 2018 period mainly due to the settlement in 2017 of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor facilities.

Returns to Providers of Capital
Net Interest Expense
The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Interest on debt	**44**	53	**142**	164
Interest income	**(2)**	(1)	**(8)**	(4)
Capitalized interest	**(1)**	(2)	**(1)**	(10)
Loss on early redemption of US Senior Notes and Debentures	**19**	6	**24**	6
Interest on finance lease obligations	**—**	1	**2**	3
Credit facility and bank charges	**4**	6	**10**	15
Other interest	**3**	—	**13**	—
Accretion of provisions	**6**	6	**18**	16
Net interest expense	**73**	69	**200**	190

Although interest on debt was down due to lower debt levels, net interest expense was higher period-over-period due to the $19 million prepayment premium relating to the early redemption of the $400 million debenture in the third quarter, the $5 million prepayment premium relating to the early redemption of the US$500 million Senior Notes during the first quarter, $5 million of costs expensed in the second quarter in connection to a project level financing that is no longer practicable, and lower capitalized interest.

Dividends to Shareholders

The following are the common and preferred shares dividends declared up to Oct. 30, 2018:

	Payable date		Common dividends per share	Preferred Series dividends per share				
Declaration date	**Common Shares**	**Preferred Shares**		**A**	**B**	**C**	**E**	**G**
Feb. 2, 2018	April 1, 2018	March 31, 2018	0.04	0.16931	0.17889	0.25169	0.32463	0.33125
April 19, 2018	July 3, 2018	July 3, 2018	0.04	0.16931	0.19951	0.25169	0.32463	0.33125
July 19, 2018	Oct. 1, 2018	Sept. 30, 2018	0.04	0.16931	0.20984	0.25169	0.32463	0.33125
Oct. 10, 2018	Jan. 1, 2019	Dec. 31, 2018	0.04	0.16931	0.22301	0.25169	0.32463	0.33125

Financial Position

The following table outlines significant changes in the Condensed Consolidated Statements of Financial Position from Sept. 30, 2018, to Dec. 31, 2017:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	(219)	Timing of receipts and payments
Trade and other receivables	(283)	Timing of customer receipts and seasonality of revenue
Prepaid expenses	22	US Wind development project costs ($11 million), and annual property tax and insurance payments ($11 million)
Inventory	45	Higher costs and lower produced volumes at our Canadian Coal operations
Restricted cash	36	Additional restricted cash related to OCP bonds
Finance lease receivables (long term)	(19)	Scheduled receipts
Property, plant, and equipment, net	(377)	Depreciation for the period ($474 million), asset impairment charges ($50 million), revisions to decommissioning and restoration costs ($27 million), and retirements and disposals ($12 million), partially offset by additions ($176 million) and acquisitions ($4 million).
Intangible assets	(23)	Amortization ($37 million), partially offset by additions ($16 million)
Risk management assets (current and long term)	(108)	Contract settlements, partially offset by favourable changes in foreign exchange rates.
Other assets	38	Project development costs related to the acquisition of two US Wind projects
Others	5	
Total decrease in assets	**(883)**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(118)	Timing of payments and accruals
Income taxes payable	(56)	Primarily due to the payment of taxes on FMG's repurchase of the Solomon Power Station
Credit facilities, long term debt, and finance lease obligations (including current portion)	(524)	Repayment of long-term debt ($1,137 million), partially offset by drawings on the credit facility ($231 million), long-term debt issued ($345 million) and unfavourable changes in foreign exchange ($61 million)
Decommissioning and other provisions (current and long term)	(14)	Liabilities settled ($27 million) and an increase in risk-adjusted discount rates ($27 million), partially offset by accretion ($18 million), and new provisions incurred ($14 million)
Deferred income tax liabilities	(17)	Increase in taxable temporary differences
Risk management liabilities (current and long term)	(47)	Contract settlements, partially offset by unfavourable changes in market price movements
Equity attributable to shareholders	(161)	Net loss ($96 million), common share dividends ($34 million), preferred share dividends ($30 million), shares purchased under NCIB ($14 million), impact of changes in our accounting policies ($14 million), partially offset by changes in non-controlling interests in TransAlta Renewables ($24 million) and net other comprehensive income ($2 million)
Non-controlling interests	60	Net earnings ($65 million) and changes in non-controlling interests in TransAlta Renewables from share issuance ($126 million), partially offset by distributions paid and payable ($131 million)
Others	(6)	
Total decrease in liabilities and equity	**(883)**	

Cash Flows

The following tables outline significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2018, compared to the same periods Sept. 30, 2017:

3 months ended Sept. 30	2018	2017	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**123**	50	73	
Provided by (used in):				
Operating activities	**159**	201	(42)	Unfavourable change in non-cash working capital
Investing activities	**(135)**	(145)	10	Lower additions to PP&E ($16 million) and intangibles ($29 million), offset by an increase in restricted cash related to the OCP debt issuance ($35 million)
Financing activities	**(51)**	(18)	(33)	Higher repayment of long-term debt ($411 million), dividends on preferred shares ($10 million) and repurchasing common shares under NCIB ($10 million), partially offset by higher borrowing on the credit facilities ($80 million) and the issuance of long-term debt ($345 million)
Translation of foreign currency cash	**(1)**	(1)	—	
Cash and cash equivalents, end of period	**95**	**87**	**8**	

9 months ended Sept. 30	2018	2017	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**314**	305	9	
Provided by (used in):				
Operating activities	**688**	545	143	Higher cash earnings ($125 million) and favourable change in non-cash working capital ($18 million)
Investing activities	**(294)**	(214)	(80)	Lower proceeds on disposals ($61 million), higher project development acquisitions ($30 million), an increase in restricted cash related to the OCP debt issuance ($35 million) and unfavourable change in non-cash investing working capital balances ($80 million), partially offset by lower additions to PP&E ($90 million) and intangibles ($29 million)
Financing activities	**(613)**	(548)	(65)	Higher repayments of long-term debt ($549 million), lower realized gains on financial instruments ($59 million) and repurchasing common shares under NCIB ($14 million), partially offset by higher borrowing on the credit facilities ($84 million), the issuance of long-term debt ($345 million), and net proceeds on issuance of TransAlta Renewables common shares ($144 million)
Translation of foreign currency cash	**—**	(1)	1	
Cash and cash equivalents, end of period	**95**	**87**	**8**	

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 Sept. 30, 2018, we provided letters of credit totalling $642 million (Dec. 31, 2017 - $677 million) and cash collateral of $37 million (Dec. 31, 2017 - $67 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
TransAlta has been participating in a line loss rule proceeding (the "LLRP") before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to, 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 TransAlta for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if TransAlta and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil; TransAlta accordingly recorded an appropriate provision in 2017.

II. FMG Disputes
The Corporation is currently engaged in two disputes with 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.

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2017 Annual Integrated Report and Note 9 of our unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2018 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2017 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. Refer to the Accounting Changes section of this MD&A for further details on the adoption of IFRS 9 *Financial Instruments* effective Jan. 1, 2018. Our risk management profile and practices have not changed materially from Dec. 31, 2017.

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

As at Sept. 30, 2018, total Level III financial instruments had a net asset carrying value of $696 million (Dec. 31, 2017 - $771 million net asset). The decrease during the period is primarily due to the settlement of contracts, 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 favourable foreign exchange rates.

2018 Financial Outlook

As a result of our strong performance during our first quarter, we revised our targets during the first quarter. The following table outlines our expectation on key financial targets for 2018:

Measure	Original Target	Revised Target
Comparable EBITDA	$950 million to $1,050 million	$1,000 million to $1,050 million
FFO	$725 million to $800 million	$750 million to $800 million
FCF	$275 million to $350 million	$300 million to $350 million
Canadian Coal capacity factor	65 to 75 per cent	Unchanged
Dividend	$0.16 per share annualized, 13 to 17 per cent payout of FCF	$0.16 per share annualized, 13 to 15 per cent payout of FCF

Range of Key Assumptions

Market	Power Prices ($/MWh)
Alberta Spot	$50 to $60
Alberta Contracted	$35 to $40
Mid-C Spot (US$)	$20 to $25
Mid-C Contracted (US$)	$47 to $53
Hydro/ Wind Resource	Long term average

Operations

Availability

Total availability of our Canadian coal fleet is expected to be in the range of 86 to 88 per cent in 2018. Availability of our other generating assets (gas, renewables) is expected to be in the range of 95 per cent in 2018. We will be accelerating our transition to gas and renewables generation, and have retired Sundance Unit 1 effective Jan. 1, 2018, retired Sundance Unit 2 effective July 31, 2018, and temporarily mothballed Sundance Unit 3 and Sundance Unit 5 effective April 1, 2018.

Market Pricing and Hedging Strategy

For 2018, power prices in Alberta are expected to be higher than 2017 due to increased carbon costs affecting the price of generation year-over-year and a lower reserve margin with the mothballing and shutdown of certain coal-fired units in 2018.

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 to be higher compared to 2017 due to lower produced volumes and increased carbon costs.

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. In 2017 we amended our fuel and rail contract such that our costs fluctuate partly with gas prices. The delivered fuel cost is expected to increase by approximately 5% over the remaining balance of the year due to higher natural 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 2018 objective for Energy Marketing is for the segment to contribute between $70 million to $80 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.

We expect to spend approximately US$240 million to construct and commission the two US wind development projects. We plan to use foreign exchange contracts to manage the foreign exchange exposure created by these projects. See the Significant and Subsequent Events section of this MD&A for further details.

Net Interest Expense
Net interest expense, excluding prepayment premiums and accretion of provisions, for 2018 is expected to be lower than in 2017 largely due to lower levels of 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.

Net Debt, Liquidity, and Capital Resources
We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to approximately $1.1 billion under our committed facilities and $95 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.

Growth 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		Expected spend in 2018	Target completion date	Details
	Estimated spend	Spent to date(1)			
Project					
Kent Hills 3 Wind Expansion(2)	37	32	28	Oct. 19, 2018	17.25 MW expansion project on our existing Kent Hills wind farms.
Pennsylvania wind development project(3)	214	83	133	2nd half of 2019	90 MW wind project with a 15-year PPA.
New Hampshire wind development project(4)	97	10	54	2nd half of 2019	29 MW wind project with two 20-year PPAs
Total	**348**	**125**	**215**		

(1) Represents amounts spent as of Sept. 30, 2018.
(2) Our 17 per cent partner on the existing Kent Hills facilities is participating in the expansion project and also owns a 17 per cent interest. They will be funding their share of the total project costs.
(3) The numbers reflected above are in CAD but the actual cash spend on this project in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD$165 million, spent to date is USD$65 million and estimated total spend in 2018 is USD$103 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.
(4) The numbers reflected above are in CAD but the actual cash spend on this project 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$8 million and expected total spend in 2018 is USD$43 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity. The project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

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 2018
Routine capital	Capital required to maintain our existing generating capacity	**32**	55 — 60
Planned major maintenance	Regularly scheduled major maintenance	**34**	60 — 65
Mine capital	Capital related to mining equipment and land purchases	**32**	35 — 45
Finance leases	Payments on finance leases	**14**	15 — 20
Total sustaining capital		**112**	**165 — 190**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**12**	20 — 30
Total sustaining and productivity capital		**124**	**185 — 220**

(1) As at Sept. 30, 2018.

Significant planned major outages for the remainder of 2018 include a major outage in our Canadian Coal segment during the fourth quarter to a unit operated by our partner.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2018:

	Canadian Coal	Gas and Renewables	Total	Lost to date(1)
GWh lost	130-170	170-250	300-420	185

(1) As at Sept. 30, 2018.

Funding of Capital Expenditures
Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, existing liquidity, and capital raised from our contracted cash flows. We have access to approximately $1.2 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

I. IFRS 15 *Revenue from Contracts with Customers*
The Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018.

The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient. Under this method, the comparative period presented in the condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2018 will not be restated and is reported under IAS 18 *Revenue*. Instead, the Corporation recognized the cumulative impact of the initial application of the standard in Deficit as at Jan. 1, 2018, as follows: Applying the significant financing component requirements to a specific contract resulted in an increase to the contract liability of $17 million, a decrease in deferred income tax liabilities of $4 million, and an increase to Deficit of $13 million.

IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer ("significant financing component"). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. The application of the significant financing component requirements results in the recognition of interest expense over the financing period and a higher amount of revenue.

Additionally, the Corporation no longer recognizes revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of its gas plants , as it was determined under IFRS 15 that the Corporation does not obtain control of the customer-supplied natural gas. This change had no impact on the cumulative impact of initial adoption as recognized in Deficit as Jan. 1, 2018.

Refer to Note 2 of the Corporation's condensed consolidated financial statements for a more detailed discussion of the Corporation's accounting policies under IFRS 15.

II. IFRS 9 *Financial Instruments*
Effective Jan. 1, 2018, the Corporation adopted IFRS 9, which introduces new requirements for:
1) The classification and measurement of financial assets and liabilities
2) The recognition and measurement of impairment of financial assets
3) General hedge accounting

In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods.

Under the new classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI. The classification and measurement depends on the contractual cash flow characteristics of the financial asset and the entity's business model for managing the financial asset. The classification requirements for financial liabilities are largely unchanged from IAS 39. While the Corporation had no direct impact of adopting the IFRS 9 classification and measurement requirements, a $1 million increase in deficit resulted from the increase in equity attributable to non-controlling interests due to IFRS 9 classification and measurement impacts at TransAlta Renewables.

IFRS 9 introduces a new impairment model for financial assets measured at amortized cost. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss. The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon application of IFRS 9.

The new general hedge accounting model is intended to be simpler and more closely focused on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness. The Corporation's qualifying hedging relationships under IAS 39 in place as at Jan. 1, 2018 also qualified for hedge accounting in accordance with IFRS 9, and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018.

Refer to Note 2 of the Corporation's condensed consolidated financial statements for a more detailed discussion of the Corporation's accounting policies under IFRS 9.

III. Change in Estimates - Useful Lives

As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(H) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the nine months ended Sept. 30, 2018 increased by approximately $29 million and the full year depreciation expense is expected to increase be approximately $38 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation, include IFRS 16 Leases. Refer to Note 3 of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 16. The Corporation has prepared a detailed project plan and is finalizing the completeness procedures and continuing the detailed contract assessment under IFRS 16. The impact on our consolidated financial statements upon adoption of IFRS 16 is currently being assessed, but it is expected to be material.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at US Coal. Typically, hydro facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q4 2017	Q1 2018	Q2 2018	Q3 2018
Revenues	638	588	446	**593**
Comparable EBITDA	275	416	225	**249**
FFO	219	318	188	**204**
Net earnings (loss) attributable to common shareholders	(145)	65	(105)	**(86)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	(0.50)	0.23	(0.36)	**(0.30)**
	Q4 2016	**Q1 2017**	**Q2 2017**	**Q3 2017**
Revenues	717	578	503	588
Comparable EBITDA	374	274	268	245
FFO	228	202	187	196
Net earnings (loss) attributable to common shareholders	61	—	(18)	(27)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	0.21	—	(0.06)	(0.09)

(1) 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 the impairment charge during the second quarter of 2018;
- 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;

- change in income tax rates in US in the fourth quarter of 2017;
- effects of non-comparable unrealized gains on intercompany financial instruments that are attributable only to the non-controlling interests in the first quarter of 2017;
- effects of the Keephills 1 outage provision in the fourth quarter of 2016;
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016, and the Sundance Unit 1 impairment charge during the second quarter of 2017;
- effects of the Mississauga facility recontracting during the fourth quarter of 2016;
- effects of changes in useful lives of certain Canadian Coal assets during the first, second, and third quarters of 2017; and
- effects of an impairment of $137 million in 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and Interim Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the *Securities Exchange Act* of 1934, as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission. Disclosure controls and procedures 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 the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Interim Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, 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 management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There have been no other changes in our internal control over financial reporting during the period ended Sept. 30, 2018, that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Interim Chief Financial Officer have concluded that, as at Sept. 30, 2018, the end of the period covered by this report, our disclosure controls and procedures were effective.

TransAlta Corporation

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2018**	2017	**2018**	2017
Revenues *(Note 4)*	**593**	588	**1,627**	1,669
Fuel, carbon costs, and purchased power	**308**	294	**764**	724
Gross margin	**285**	294	**863**	945
Operations, maintenance, and administration	**120**	119	**376**	371
Depreciation and amortization	**146**	158	**422**	455
Asset impairment charge *(Note 3)*	**38**	—	**50**	20
Taxes, other than income taxes	**7**	7	**23**	23
Net other operating income *(Note 5)*	**(16)**	(10)	**(194)**	(30)
Operating income (loss)	**(10)**	20	**186**	106
Finance lease income	**2**	15	**7**	47
Net interest expense *(Note 6)*	**(73)**	(69)	**(200)**	(190)
Foreign exchange gain (loss)	**(8)**	(8)	**(15)**	(7)
Other income (loss)	**1**	(1)	**1**	1
Earnings (loss) before income taxes	**(88)**	(43)	**(21)**	(43)
Income tax expense (recovery) *(Note 7)*	**(21)**	(5)	**10**	(41)
Net earnings (loss)	**(67)**	(38)	**(31)**	(2)
Net earnings (loss) attributable to:				
TransAlta shareholders	**(76)**	(17)	**(96)**	(25)
Non-controlling interests *(Note 8)*	**9**	(21)	**65**	23
	(67)	(38)	**(31)**	(2)
Net loss attributable to TransAlta shareholders	**(76)**	(17)	**(96)**	(25)
Preferred share dividends *(Note 14)*	**10**	10	**30**	20
Net loss attributable to common shareholders	**(86)**	(27)	**(126)**	(45)
Weighted average number of common shares outstanding in the period *(millions)*	**287**	288	**287**	288
Net loss per share attributable to common shareholders, basic and diluted *(Note 13)*	**(0.30)**	(0.09)	**(0.44)**	(0.16)

See accompanying notes.

TransAlta Corporation

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2018**	2017	**2018**	2017
Net earnings (loss)	**(67)**	(38)	**(31)**	(2)
Other comprehensive income (loss)				
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**10**	14	**28**	2
Losses on derivatives designated as cash flow hedges, net of tax(2)	**—**	(1)	**—**	(1)
Total items that will not be reclassified subsequently to net earnings	**10**	13	**28**	1
Gains (losses) on translating net assets of foreign operations, net of tax(3)	**(29)**	(61)	**31**	(95)
Reclassification of translation gains on net assets of divested foreign operations(4)	**—**	—	**—**	(9)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(5)	**10**	30	**(14)**	53
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax(6)	**—**	—	**—**	14
Gains on derivatives designated as cash flow hedges, net of tax(7)	**(26)**	10	**2**	87
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(8)	**8**	(18)	**(46)**	(63)
Total items that will be reclassified subsequently to net earnings	**(37)**	(39)	**(27)**	(13)
Other comprehensive income (loss)	**(27)**	(26)	**1**	(12)
Total comprehensive income (loss)	**(94)**	(64)	**(30)**	(14)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**(101)**	(12)	**(94)**	(25)
Non-controlling interests *(Note 8)*	**7**	(52)	**64**	11
	(94)	(64)	**(30)**	(14)

(1) Net of income tax expense of 4 and 10 for the three and nine months ended Sept. 30, 2018 (2017 - 5 and 1 expense).
(2) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2018 (2017 - nil).
(3) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2018 (2017 - nil and 1 recovery).
(4) Net of reclassification of income tax expense of nil for the three and nine months ended Sept. 30, 2018 (2017 - nil and 11 expense).
(5) Net of income tax recovery of 1 and 3 for three months and nine months ended Sept. 30, 2018 (2017 - 3 and 5 expense).
(6) Net of reclassification of income tax expense of nil for three months and nine months ended Sept. 30, 2018 (2017 - nil and 2 recovery).
(7) Net of income tax recovery of 6 and expense of 1 for three months and nine months ended Sept. 30, 2018 (2017 - 2 and 53 expense).
(8) Net of reclassification of income tax recovery of 2 and expense of 13 for the three and nine months ended Sept. 30, 2018 (2017 - 8 and 39 expense).

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Financial Position
(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2018**	Dec. 31, 2017
Cash and cash equivalents	**95**	314
Restricted cash *(Note 12)*	**66**	—
Trade and other receivables	**650**	933
Prepaid expenses	**46**	24
Risk management assets *(Notes 9 and 10)*	**162**	219
Inventory	**264**	219
	1,283	1,709
Restricted cash *(Note 12)*	**—**	30
Long-term portion of finance lease receivables	**196**	215
Property, plant, and equipment *(Note 11)*		
Cost	**13,049**	12,973
Accumulated depreciation	**(6,848)**	(6,395)
	6,201	6,578
Goodwill	**464**	463
Intangible assets	**341**	364
Deferred income tax assets	**28**	24
Risk management assets *(Notes 9 and 10)*	**633**	684
Other assets	**275**	237
Total assets	**9,421**	10,304
Accounts payable and accrued liabilities	**477**	595
Current portion of decommissioning and other provisions	**74**	67
Risk management liabilities *(Notes 9 and 10)*	**64**	101
Income taxes payable	**8**	64
Dividends payable *(Note 13)*	**37**	34
Current portion of long-term debt and finance lease obligations *(Note 12)*	**132**	747
	792	1,608
Credit facilities, long-term debt, and finance lease obligations *(Note 12)*	**3,051**	2,960
Decommissioning and other provisions	**382**	403
Deferred income tax liabilities	**532**	549
Risk management liabilities *(Notes 9 and 10)*	**30**	40
Defined benefit obligation and other long-term liabilities	**350**	359
Equity		
Common shares *(Note 13)*	**3,074**	3,094
Preferred shares *(Note 14)*	**942**	942
Contributed surplus	**11**	10
Deficit	**(1,357)**	(1,209)
Accumulated other comprehensive income	**495**	489
Equity attributable to shareholders	**3,165**	3,326
Non-controlling interests *(Note 8)*	**1,119**	1,059
Total equity	**4,284**	4,385
Total liabilities and equity	**9,421**	10,304

Commitments and contingencies *(Note 15)*

Subsequent events *(Note 17)*

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Changes in Equity
(in millions of Canadian dollars)

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

See accompanying notes.

9 months ended Sept. 30, 2017	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings (loss)	—	—	—	(25)	—	(25)	23	(2)
Other comprehensive income (loss)								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(37)	(37)	—	(37)
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	23	23	—	23
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	2	2	—	2
Intercompany available-for-sale investments	—	—	—	—	12	12	(12)	—
Total comprehensive income (loss)				(25)	—	(25)	11	(14)
Common share dividends	—	—	—	(24)	—	(24)	—	(24)
Preferred share dividends	—	—	—	(20)	—	(20)	—	(20)
Changes in non-controlling interests in TransAlta Renewables	—	—	—	(54)	4	(50)	50	—
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests *(Note 8)*	—	—	—	—	—	—	(130)	(130)
Balance, Sept. 30, 2017	3,094	942	10	(1,056)	403	3,393	1,083	4,476

See accompanying notes.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2018**	2017	**2018**	2017
Operating activities				
Net earnings (loss)	**(67)**	(38)	**(31)**	(2)
Depreciation and amortization *(Note 16)*	**180**	176	**523**	509
Gain on sale of assets	**(1)**	1	**(1)**	1
Accretion of provisions *(Note 6)*	**6**	6	**18**	17
Decommissioning and restoration costs settled	**(10)**	(5)	**(23)**	(12)
Deferred income tax expense (recovery) *(Note 7)*	**(20)**	(10)	**(8)**	(58)
Unrealized (gain) loss from risk management activities	**1**	(14)	**1**	(47)
Unrealized foreign exchange (gains) losses	**6**	13	**23**	14
Provisions	**2**	3	**7**	3
Asset impairment charges *(Note 3)*	**38**	—	**50**	20
Other non-cash items	**53**	48	**104**	93
Cash flow from operations before changes in working capital	**188**	180	**663**	538
Change in non-cash operating working capital balances	**(29)**	21	**25**	7
Cash flow from operating activities	**159**	201	**688**	545
Investing activities				
Additions to property, plant, and equipment *(Note 11)*	**(93)**	(109)	**(176)**	(266)
Additions to intangibles	**(6)**	(35)	**(16)**	(45)
Restricted cash *(Notes 12)*	**(35)**	—	**(35)**	—
Acquisition of renewable energy development projects *(Note 3)*	**—**	—	**(30)**	—
Proceeds on sale of property, plant, and equipment	**(1)**	1	**—**	1
Proceeds on sale of Wintering Hills facility	**—**	—	**—**	61
Decrease in finance lease receivable	**15**	14	**44**	44
Decrease in loan receivable *(Note 19)*	**2**	—	**2**	—
Other	**4**	1	**5**	(1)
Change in non-cash investing working capital balances	**(21)**	(17)	**(88)**	(8)
Cash flow from (used in) investing activities	**(135)**	(145)	**(294)**	(214)
Financing activities				
Net increase (repayment) in borrowings under credit facilities *(Note 12)*	**127**	47	**231**	147
Repayment of long-term debt *(Note 12)*	**(412)**	(1)	**(1,137)**	(588)
Issuance of long-term debt *(Note 12)*	**345**	—	**345**	—
Dividends paid on common shares *(Note 13)*	**(11)**	(12)	**(34)**	(35)
Dividends paid on preferred shares *(Note 14)*	**(20)**	(10)	**(30)**	(30)
Net proceeds on sale of non-controlling interest in subsidiary *(Notes 3 and 13)*	**—**	—	**144**	—
Repurchase of common shares under NCIB *(Note 13)*	**(10)**	—	**(14)**	—
Realized gains (losses) on financial instruments	**—**	—	**48**	107
Distributions paid to subsidiaries' non-controlling interests *(Note 8)*	**(42)**	(38)	**(123)**	(136)
Decrease in finance lease obligations *(Note 12)*	**(5)**	(4)	**(13)**	(13)
Other	**(23)**	—	**(30)**	—
Cash flow used in financing activities	**(51)**	(18)	**(613)**	(548)
Cash flow from operating, investing, and financing activities	**(27)**	38	**(219)**	(217)
Effect of translation on foreign currency cash	**(1)**	(1)	**—**	(1)
Decrease in cash and cash equivalents	**(28)**	37	**(219)**	(218)
Cash and cash equivalents, beginning of period	**123**	50	**314**	305
Cash and cash equivalents, end of period	**95**	87	**95**	87
Cash income taxes paid	**4**	3	**79**	9
Cash interest paid	**30**	22	**134**	140

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 Oct. 30, 2018.

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 and to Note 2 for information regarding judgments and estimates.

2. Significant Accounting Policies

A. Current Accounting Changes

I. IFRS 15 *Revenue from Contracts with Customers*

The Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018. As a result, the Corporation has changed its accounting policy for revenue recognition, which is outlined below.

The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are not completed contracts at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to the Corporation's most recent annual report for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard in Deficit as at Jan. 1, 2018. Applying the significant financing component requirements to a specific contract resulted in an increase to the contract liability of $17 million, a decrease in deferred income tax liabilities of $4 million, and an increase to Deficit of $13 million. IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer ("significant financing component"). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. The application of the significant financing component requirements results in the recognition of interest expense over the financing period and a higher amount of revenue.

Additionally, the Corporation no longer recognizes revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of its gas plants , as it was determined under IFRS 15 that the Corporation does not obtain control of the customer-supplied natural gas.

Refer to the discussion below, and to Note 4 for a breakdown of the Corporation's revenues from contracts with customers and revenues from other sources.

The following tables summarize the financial statement line items impacted by adopting IFRS 15 as at and for the three and nine months ended Sept. 30, 2018.

Condensed Consolidated Statement of Earnings (Loss)

3 months ended Sept. 30, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Revenues	595	(2)	593
Fuel, carbon costs, and purchased power	(311)	3	(308)
Net interest expense	(71)	(2)	(73)
Net earnings impact	(66)	(1)	(67)

9 months ended Sept. 30, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Revenues	1,630	(3)	1,627
Fuel, carbon costs, and purchased power	(771)	7	(764)
Net interest expense	(195)	(5)	(200)
Net earnings impact	(30)	(1)	(31)

Condensed Consolidated Statements of Financial Position

As at Sept. 30, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Deferred income tax liabilities	536	(4)	532
Defined benefit obligation and other long-term liabilities (contract liability)	332	18	350
Deficit	(1,343)	14	(1,357)

There were no impacts to the statement of cash flows as a result of adopting IFRS 15.

i) Revenue from Contracts with Customers

The majority of the Corporation's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, renewable attributes and byproducts of power generation. The Corporation evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Corporation's performance to date. The Corporation excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

The majority of the Corporation's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, renewable attributes and byproducts of power generation. Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Corporation's contracts may contain more than one performance obligation.

Transaction Price

The Corporation allocates the transaction price in the contract to each performance obligation. Transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration includes both variability in quantity and pricing. The consideration contained in some of the Corporation's contracts with customers is primarily variable. Variable consideration is assessed at each reporting period to determine whether the constraint is lifted.

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Corporation expects to be entitled to in exchange for transferring the good or service. The Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their relative standalone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition

The nature, timing of recognition of satisfied performance obligations, and payment terms for the Corporation's goods and services are described below:

Good or Service	***Description***
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (i.e., monthly) in an amount representative of availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract Power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal Energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Renewable Attributes	Renewable attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for renewable attributes in conjunction with the purchase of power in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the renewable attributes. Obligations to deliver renewable attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Corporation's Canadian and US coal operations, and the sale of coal to third parties. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

The Corporation recognizes a contract asset or contract liability for contracts where either party has performed. A contract liability is recorded when the Corporation receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Corporation has rights to consideration for the completion of a performance obligations before it has invoiced the customer. The Corporation recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

The Corporation recognizes a significant financing component where the timing of payment from the customer differs from the Corporation's performance under the contract and where that difference is the result of the Corporation financing the transfer of goods and services.

Significant Judgments

Identification of performance obligations

Where contracts contain multiple promises for goods or services, management exercises judgement in determining whether goods or services constitute distinct goods or services or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

Transaction price

In determining the transaction price and estimates of variable consideration, management considers past history of customer usage and capacity requirements, in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of transaction price to performance obligations
The Corporation’s contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of performance obligations
The satisfaction of performance obligations requires management to make judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient can be relied upon in measuring progress toward complete satisfaction of performance obligations. The invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

ii) Revenue from Other Sources
Lease revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with leases are recognized as outlined in Note 2(R) of the Corporation's most recent annual report.

Revenue from derivatives
Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the condensed consolidated statements of financial position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

II. IFRS 9 *Financial Instruments*
Effective Jan. 1, 2018, the Corporation adopted IFRS 9, which introduces new requirements for:

1) The classification and measurement of financial assets and liabilities
2) The recognition and measurement of impairment of financial assets
3) General hedge accounting

In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods. The impact of adopting IFRS 9 was recognized in Deficit at Jan. 1, 2018. While the Corporation had no direct impact of adopting IFRS 9, a $1 million increase in Deficit resulted from the increase in equity attributable to non-controlling interests due to IFRS 9 impacts at TransAlta Renewables Inc. ("TransAlta Renewables").

The Corporation's accounting policies under IFRS 9 are outlined below. For more information on the Corporation's accounting policies under IAS 39 for the period ended Sept. 30, 2017, refer to Note 2 of the Corporation’s most recent annual consolidated financial statements.

a. Classification and Measurement
IFRS 9 introduces the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Corporation’s business model for the financial asset. All financial assets and financial liabilities, including derivatives, are recognized at fair value on the consolidated statements of financial position when the Corporation becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss (“FVTPL”), or at fair value through other comprehensive income (“FVTOCI”).

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those which have contractual cash flows arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

The Corporation enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk, and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g. financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

The Corporation's management reviewed and assessed the classifications of its existing financial instruments as at Jan. 1, 2018, based on the facts and circumstances that existed at that date, as shown below. None of the reclassifications had a significant impact on the Corporation's financial position, earnings (loss), other comprehensive income (loss) or total comprehensive income (loss) after the date of initial application.

Financial instrument	**IAS 39 category**	**IFRS 9 classification**
Cash and cash equivalents	Loans and receivables	Amortized cost
Restricted cash	Loans and receivables	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost
Long-term portion of finance lease receivables	Loans and receivables	Amortized cost
Loan receivable (other assets)	Loans and receivables	Amortized cost
Risk management assets (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management assets (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost
Dividends payable	Other financial liabilities	Amortized cost
Risk management liabilities (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management liabilities (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Credit facilities and long-term debt	Other financial liabilities	Amortized cost

b. Impairment of Financial Assets
IFRS 9 introduces a new impairment model for financial assets measured at amortized cost as well as certain other instruments. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk.

The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition, or if the financial asset is a purchased or originated credit-impaired financial asset.

If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

IFRS 9 permits a simplified approach for measuring the loss allowance for trade receivables, contract assets and lease receivables at an amount equal to lifetime expected credit losses under certain circumstances. The Corporation measures its trade receivables, contract assets recognized under IFRS 15 using the simplified approach. The Corporation uses the general approach to measure the expected credit loss for lease receivables.

The assessment of the expected credit loss is based on historical data, and adjusted by forward-looking information. Forward-looking information utilized includes third-party default rates over time, dependent on credit ratings.

The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon application of IFRS 9 and no loss allowance was recognized.

c. General Hedge Accounting
IFRS 9 retains the three types of hedges from IAS 39 (fair value hedges, cash flow hedges and hedges of a net investment in a foreign operation), but increases flexibility as to the types of transactions that are eligible for hedge accounting.

The effectiveness test of IAS 39 is replaced by the principle of an "economic relationship", which requires that the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. Additionally, retrospective hedge effectiveness testing is no longer required under IFRS 9.

In accordance with IFRS 9's transition provisions for hedge accounting, the Corporation has applied the IFRS 9 hedge accounting requirements prospectively from the date of initial application on Jan. 1, 2018, and comparative figures have not been restated. The Corporation's qualifying hedging relationships under IAS 39 in place as at Jan. 1, 2018 also qualified for hedge accounting in accordance with IFRS 9, and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018. As the critical terms of the hedging instruments match those of their corresponding hedged items, all hedging relationships continue to be effective under IFRS 9's effectiveness assessment. The Corporation has not designated any hedging relationships under IFRS 9 that would not have met the qualifying hedge accounting criteria under IAS 39. Further details of the Corporation's hedging activities are disclosed in Notes 9 and 10.

The Corporation's risk management objective and strategy, including risk management instruments and their key terms, are detailed in Notes 10A and 10C.

In certain cases, the Corporation purchases non-financial items in a foreign currency, for which it may enter into forward contracts to hedge foreign currency risk on the anticipated purchases. Both IAS 39 and IFRS 9 require hedging gains and losses to be basis adjusted to the initial carrying amount of non-financial hedged items once recognized (such as PP&E), but under IFRS 9, these adjustments are no longer considered reclassification adjustments and do not affect other comprehensive income. Under IFRS 9, these amounts will be directly transferred to the asset and will be reflected in the statement of changes in equity as a reclassification from accumulated other comprehensive income.

The application of IFRS 9 hedge accounting requirements has no other impact on the results and financial position of the Corporation for the current or prior years.

III. Change in Estimates - Useful Lives

As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(H) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the nine months ended Sept. 30, 2018 increased by approximately $29 million and the full year depreciation expense is expected to increase by approximately $38 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation, include IFRS 16 Leases. Refer to Note 3 of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 16. The Corporation has prepared a detailed project plan and is finalizing the completeness procedures and continuing the detailed contract assessment under IFRS 16. The impact on the Corporation's consolidated financial statements upon adoption of IFRS 16 is currently being assessed, but it is expected to be material.

C. Comparative Figures

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

3. Significant Events

A. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

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

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

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

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

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility will be used for general corporate purposes, including ongoing construction costs associated with the US wind development, described in 3(I) below.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing, approximately 61 per cent of the outstanding common shares of TransAlta Renewables.

C. $345 Million Financing

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

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

D. Early Redemption of $400 million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of $400 million . The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest. See note 12 for further details.

E. Sundance Unit 2 Retirement

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

F. Normal Course Issuer Bid

On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares ("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. Any Common Shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018 and ends on March 13, 2019 or such earlier date on which the maximum number of Common Shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 102,039 Common Shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 Common Shares for the six months ended February 28, 2018) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the nine months ended Sept. 30, 2018, the Corporation purchased and cancelled 1,907,200 Common Shares at an average price of $7.34 per Common Share, for a total cost of $14 million. See Note 13 for further details. Further transactions under the NCIB will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

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 for the three months ended March 31, 2018. See Note 12 for further details.

H. Balancing Pool Terminates the Alberta Sundance Power Purchase Arrangements

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool of the termination of the Sundance B and C Power Purchase Arrangements ("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 excludes 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.

I. 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 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 ("US HoldCo") acquired Big Level on Feb. 20, 2018, whereas the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the acquisition to close in early 2019.

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 will own the US wind projects directly and TA Power will issue to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US wind projects. The construction and acquisition costs of the two US wind projects are to be funded by TransAlta Renewables and are estimated to be US$240 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 shall 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.

During the nine months ended Sept. 30, 2018, TransAlta Renewables funded approximately $61 million (US$48 million) of construction costs.

4. Revenue from Contracts with Customers

Disaggregation of Revenue from Contracts with Customers

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and green attributes, leasing of power facilities, and from energy marketing and trading activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

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

(1) Includes merchant revenue and other miscellaneous.

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

(1) Includes merchant revenue and other miscellaneous.

5. Net Other Operating Income

Net other operating (income) losses are comprised of the following:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Alberta Off-Coal Agreement	**(10)**	(10)	**(30)**	(30)
Termination of Sundance B and C PPAs	**—**	—	**(157)**	—
Insurance recoveries	**(6)**	—	**(7)**	—
Net other operating income	**(16)**	(10)	**(194)**	(30)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030.

In July 2018, the Corporation obtained financing against the OCA payments (See Note 3 and 12).

B. 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 Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Interest on debt	**44**	53	**142**	164
Interest income	**(2)**	(1)	**(8)**	(4)
Capitalized interest	**(1)**	(2)	**(1)**	(10)
Loss on early redemption *(Note 12)*	**19**	6	**24**	6
Interest on finance lease obligations	**—**	1	**2**	3
Credit facility fees and bank charges	**4**	6	**10**	15
Other interest and fees(1)	**3**	—	**13**	—
Accretion of provisions	**6**	6	**18**	16
Net interest expense	**73**	69	**200**	190

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

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Current income tax expense (recovery)	**(1)**	5	**18**	17
Deferred income tax expense related to the origination and reversal of temporary differences	**(24)**	(14)	**(26)**	(35)
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets(1)	**4**	4	**18**	(23)
Income tax expense (recovery)	**(21)**	(5)	**10**	(41)

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Current income tax expense (recovery)	**(1)**	5	**18**	17
Deferred income tax expense (recovery)	**(20)**	(10)	**(8)**	(58)
Income tax expense (recovery)	**(21)**	(5)	**10**	(41)

(1) During the three and nine months ended Sept. 30, 2018, the Corporation recorded a writedown of deferred income tax assets of $4 million and $18 million (Sept. 30, 2017 - $4 million writedown and $23 million reversal), respectively. 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. Recognized other comprehensive income during the prior period has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

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 150 MW Kent Hills wind farm and the 17.25 MW Kent Hills 3 expansion project located in New Brunswick.

The Corporation's share of ownership and equity participation in TransAlta Renewables during the nine months ended Sept. 30, 2018 and 2017 is as follows:

Period	**Ownership and voting rights percentage**	**Equity participation percentage(1)**
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 31, 2018(2)	61.1	61.1
Sept. 30, 2018(3)	61.0	61.0

(1) As the Class B shares issued to the Corporation in the sale of Australian assets were determined to constitute financial liabilities of TransAlta Renewables and did not participate in earnings until commissioning of the South Hedland facility, they were excluded from the allocation of equity and earnings until converted to common shares on Aug. 1, 2017.
(2) See Note 3 for further details on TransAlta Renewables common shares issuance that occurred during the second quarter of 2018.
(3) 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.

Amounts attributable to non-controlling interests are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Net earnings				
TransAlta Cogeneration L.P.	**4**	3	**10**	25
TransAlta Renewables	**5**	(24)	**55**	(2)
	9	(21)	**65**	23
Total comprehensive income				
TransAlta Cogeneration L.P.	**4**	3	**10**	25
TransAlta Renewables	**3**	(55)	**54**	(14)
	7	(52)	**64**	11
Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**23**	16	**62**	72
TransAlta Renewables	**19**	22	**61**	64
	42	38	**123**	136

As at	**Sept. 30, 2018**	Dec. 31, 2017
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**195**	247
TransAlta Renewables	**924**	812
	1,119	1,059
Non-controlling interests per share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.0**	36.0

9. Financial Instruments

A. Financial Assets and Liabilities – Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost.

B. Fair Value of Financial Instruments

I. Level I, II, and III Fair Value Measurements

The Level I, II, and III classifications in the fair value hierarchy utilized by the 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 and liabilities and long-term debt measured and carried at fair value, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

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

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

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

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

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at	Sept. 30, 2018		December 31, 2017	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**776**	**+95 -95**	853	+130 -130
Unit contingent power purchases	**31**	**+4 -6**	44	+7 -9
Structured products - Eastern US	**5**	**+5 -5**	17	+8 -7
Long-term wind energy sale - Eastern US	**(28)**	**+17 -17**	—	—
Others	**6**	**+7 -6**	4	+12 -12

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 beyond 2020, 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 Sept. 30, 2018 are US$24 - US$35 (Dec. 31, 2017 - US$25 - US$34). The sensitivity analysis has been prepared using the Corporation's assessment that a US$5 (Dec. 31, 2017 - 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 strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2017 to Sept. 30, 2018, the base fair value and the sensitivity values have increased by approximately $27 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 Sept. 30, 2018, are nil (Dec. 31, 2017 - nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2017 – 2.20 per cent to 2.76 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, 2017 - 1.1 per cent to 1.94 per cent) and a change in volumetric discount rates of approximately 8.7 per cent to 10.2 per cent (Dec. 31, 2017 - 7.77 per cent to 10.46 per cent), which approximate one standard deviation for each input.

iii. Structured Products - Eastern US

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

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Sept. 30, 2018, are 80 per cent to 128 per cent and 76 per cent to 122 per cent (Dec. 31, 2017 – 75 per cent to 159 per cent and 71 per cent to 88 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 2.7 per cent to 5 per cent (Dec. 31, 2017 - 7 per cent) and a change in non-standard shape factors of approximately 3 per cent to 4 per cent (Dec. 31, 2017 - 6 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Sept. 30, 2018, are 19 per cent to 41 per cent and 70 per cent (Dec. 31, 2017 – 18 per cent to 54 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 24 per cent to 28 per cent and 30 per cent, respectively (Dec. 31, 2017 -27 per cent to 32 per cent and 10 per cent).

iv. Long-Term Wind Energy Sale - Eastern US

In relation to the acquisition of the US wind project (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 2023 and 2022, respectively. Forward power and REC price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2018 are US$31-US$76 and 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$5, and a change in REC prices of US$1 as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Sept. 30, 2018, are as follows: Level I - nil (Dec. 31, 2017 - $1 million net liability), Level II - $2 million net liability (Dec. 31, 2017 - $42 million net liability), Level III - $696 million net asset (Dec. 31, 2017 - $771 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2018 are primarily attributable to the settlement of contracts, partially offset by favourable foreign exchange rates.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities during the nine months ended Sept. 30, 2018 and 2017, respectively:

	9 months ended Sept. 30, 2018			9 months ended Sept. 30, 2017		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**719**	**52**	**771**	726	32	758
Changes attributable to:						
Market price changes on existing contracts	**(9)**	**7**	**(2)**	95	1	96
Market price changes on new contracts	**—**	**—**	**—**	—	1	1
Contracts settled	**(60)**	**(35)**	**(95)**	(39)	(4)	(43)
Change in foreign exchange rates	**26**	**—**	**26**	(58)	(1)	(59)
Transfers into (out of) Level III	**—**	**(4)**	**(4)**	—	—	—
Net risk management assets at end of period	**676**	**20**	**696**	724	29	753
Additional Level III information:						
Gains recognized in other comprehensive income	**17**	**—**	**17**	37	—	37
Total gains (losses) included in earnings before income taxes	**60**	**7**	**67**	39	1	40
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(28)**	**(28)**	—	(3)	(3)

III. Other Risk Management Assets and Liabilities

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

Other risk management assets and liabilities with a total net asset fair value of $7 million as at Sept. 30, 2018 (Dec. 31, 2017 - $34 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the nine months ended Sept. 30, 2018 are primarily attributable to the settlement of contracts.

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				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value**
Long-term debt - Sept. 30, 2018	**—**	**3,109**	**—**	**3,109**	**3,124**
Long-term debt - Dec. 31, 2017	—	3,708	—	3,708	3,638

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, restricted cash, 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 and the finance lease receivables 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 Sept. 30		**9 months ended Sept. 30**	
	2018	2017	**2018**	2017
Unamortized net gain at beginning of period	**61**	113	**105**	148
New inception gain (loss)	**–**	5	**(14)**	9
Change in foreign exchange rates	**(2)**	(4)	**2**	(8)
Amortization recorded in net earnings during the year	**(9)**	(8)	**(43)**	(43)
Unamortized net gain at end of period	**50**	106	**50**	106

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 applies hedge accounting to those hedging commodity price risk and foreign currency risk.

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

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

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

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

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

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

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

B. Net Risk Management Assets and Liabilities

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

As at Sept. 30, 2018

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**76**	**18**	**94**
Long-term	**596**	**4**	**600**
Net commodity risk management assets	**672**	**22**	**694**
Other			
Current	**—**	**4**	**4**
Long-term	**—**	**3**	**3**
Net other risk management assets (liabilities)	**—**	**7**	**7**
Total net risk management assets	**672**	**29**	**701**

As at Dec. 31, 2017

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	74	7	81
Long-term	636	11	647
Net commodity risk management assets	710	18	728
Other			
Current	—	37	37
Long-term	—	(3)	(3)
Net other risk management assets (liabilities)	—	34	34
Total net risk management assets (liabilities)	710	52	762

During the quarter, the Corporation designated an additional $20 million of U.S. denomintated debt, for a total of USD $400 million, as a part of the hedge of TransAlta's net investment in foreign operations.

C. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments, which are also more fully discussed in Note 14(b) of the Corporation's most recent annual consolidated financial statements.

I. Market Risk

a. Commodity Price Risk

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

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

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

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2018, associated with the Corporation's proprietary trading activities was $3 million (Dec. 31, 2017 - $5 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 Sept. 30, 2018, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $9 million (Dec. 31, 2017 - $16 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2018, associated with these transactions was $7 million (Dec. 31, 2017 - $5 million).

b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the US dollar, the Japanese yen, the euro 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, and the US wind development projects. Further discussion on Currency Rate Risk can be found in Note 14(B)(I)(c) of the Corporation's most recent annual consolidated financial statements.

II. Credit Risk

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

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Sept. 30, 2018:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1)	86	14	**100**	**650**
Long-term finance lease receivables	99	1	**100**	**196**
Risk management assets(1)	99	1	**100**	**795**
Loan receivable(2)	—	100	**100**	**35**
Total				**1,676**

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

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at Sept. 30, 2018, was $19 million (Dec. 31, 2017 - $40 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. As at Sept. 30, 2018, 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:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Accounts payable and accrued liabilities	477	—	—	—	—	—	477
Long-term debt[1]	43	99	486	91	872	1,562	3,153
Commodity risk management liabilities	26	102	98	115	108	245	694
Other risk management (assets) liabilities	2	1	—	—	4	—	7
Finance lease obligations	4	16	13	7	4	15	59
Interest on long-term debt and finance lease obligations[2]	46	154	146	124	110	758	1,338
Dividends payable	37	—	—	—	—	—	37
Total	**635**	**372**	**743**	**337**	**1,098**	**2,580**	**5,765**

(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 Sept. 30, 2018, the Corporation had posted collateral of $108 million (Dec. 31, 2017 - $131 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 $81 million (Dec. 31, 2017 - $96 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, 2017	95	2,457	910	2,191	602	95	228	6,578
Additions	—	—	—	1	—	168	7	176
Additions - finance lease	—	—	—	—	3	—	—	3
Acquisitions *(Note 3)*	—	—	—	—	—	4	—	4
Asset impairment charges *(Note 3)*	—	(38)	—	(12)	—	—	—	(50)
Depreciation	—	(218)	(59)	(92)	(93)	—	(12)	(474)
Revisions and additions to decommissioning and restoration costs	—	(5)	(1)	—	(21)	—	—	(27)
Retirement of assets and (disposals)	(1)	(5)	(1)	(3)	(2)	—	—	(12)
Change in foreign exchange rates	1	10	(19)	9	1	—	(1)	1
Transfers	—	33	19	8	25	(89)	6	2
As at Sept. 30, 2018	**95**	**2,234**	**849**	**2,102**	**515**	**178**	**228**	**6,201**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive, or planned maintenance.

12. Credit Facilities, Long-Term Debt, and Finance Lease Obligations

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at	Sept. 30, 2018			Dec. 31, 2017		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**258**	**258**	**3.3%**	27	27	2.8%
Debentures	**647**	**651**	**5.8%**	1,046	1,051	6.0%
Senior notes(3)	**902**	**913**	**5.4%**	1,499	1,510	6.0%
Non-recourse(4)	**1,278**	**1,292**	**4.3%**	1,022	1,032	4.3%
Other(5)	**39**	**39**	**9.1%**	44	44	9.2%
	3,124	**3,153**		3,638	3,664	
Finance lease obligations	**59**			69		
	3,183			3,707		
Less: current portion of long-term debt	**(116)**			(729)		
Less: current portion of finance lease obligations	**(16)**			(18)		
Total current long-term debt and finance lease obligations	**(132)**			(747)		
Total credit facilities, long-term debt, and finance lease obligations	**3,051**			2,960		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Sept. 30, 2018 - US$0.7 billion (Dec. 31, 2017 - US$1.2 billion).
(4) Includes US$1 million at Sept. 30, 2018 (Dec. 31, 2017 - US$27 million).
(5) Includes US$21 million at Sept. 30, 2018 (Dec. 31, 2017 - US$24 million) of tax equity financing.

On March 15, 2018, the Corporation early redeemed its outstanding 6.650 per cent US $500 million Senior Notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

As a result of the Corporation's repayment of its US$500 million Senior Notes the Corporation now has US$400 million (Dec. 31, 2017 - US$480 million) of US-dollar-denominated debt designated as hedges of its net investment in foreign operations.

On June 27, 2018, the Corporation paid out the US$25 million non-recourse debt related to its Mass Solar projects. (See Note 3).

During the second quarter of 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

On July 20, 2018, the Corporation monetized the OCA and closed a $345 million bond offering through its indirect wholly-owned subsidiary, TransAlta OCP, by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

On Aug. 2, 2018, the Corporation early redeemed all of it's outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

The Corporation has a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, comprised of the Corporation's $1.3 billion (Dec. 31, 2017 - $1.0 billion) committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $0.5 billion (Dec. 31, 2017 - $0.5 billion), and the Corporation's $0.2 billion committed bilateral facilities. These facilities were renewed during the second quarter and expire in 2022, 2022 and 2020 respectively. The $1.8 billion (Dec. 31, 2017 - $1.5 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business.

In total, $1.1 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At Sept. 30, 2018, the $0.9 billion (Dec. 31, 2017 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (Dec. 31, 2017 - $27 million) and letters of credit of $0.6 billion (Dec. 31, 2017 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.1 billion available under the credit facilities, the Corporation also has $0.1 billion of available cash and cash equivalents.

The Corporation's total outstanding letters of credit as at Sept. 30, 2018 were $642 million (Dec. 31, 2017 - $677 million), including TransAlta Renewables outstanding letters of credit of $68 million (Dec. 31, 2017 - $69 million) with no (Dec. 31, 2017 - 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 Sept. 30, 2018, 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 $1,277 million (Dec. 31, 2017 - $1,022 million) that are subject to customary financing conditions and covenants that may restrict the Corporation’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2018. At Sept. 30, 2018, $40 million (Dec. 31, 2017 -$35 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Sept. 30, 2018.

C. Security

Non-recourse debts of $789 million in total (Dec. 31, 2017 - $848 million) are each secured by a first ranking charge over all of the respective assets of the Corporation’s subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of $1,027 million at Sept. 30, 2018 (Dec. 31, 2017 - $1,107 million). At Sept. 30, 2018, a non-recourse bond of approximately $146 million (Dec. 31, 2017 - $174 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The new TransAlta OCP bonds with a carrying value of $343 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, 2017 - $30 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, including commissioning of the Kent Hills 3 wind project.

The Corporation also has $35 million (Dec. 31, 2017 - nil) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2019.

13. 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 Sept. 30				9 months ended Sept. 30			
	2018		2017		**2018**		2017	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount	**Common shares** *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**287.3**	**3,088**	287.9	3,095	**287.9**	**3,094**	287.9	3,095
Shares purchased and retired under NCIB	**(1.3)**	**(14)**	—	—	**(1.9)**	**(20)**	—	—
	286.0	**3,074**	287.9	3,095	**286.0**	**3,074**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**—**	—	(1)	**—**	**—**	—	(1)
Issued and outstanding, end of period	**286.0**	**3,074**	287.9	3,094	**286.0**	**3,074**	287.9	3,094

B. NCIB Program

Shares purchased by the Corporation under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the nine months ended Sept. 30, 2018:

As at		**Sept. 30, 2018**	Dec. 31, 2017
Total shares purchased		**1,907,200**	—
Average purchase price per share	**$**	**7.34**	—
Total cost		**14**	—
Weighted average book value of shares cancelled		**20**	—
Increase to retained earnings		**(6)**	—

C. Earnings per Share

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Net loss attributable to common shareholders	**(86)**	(27)	**(126)**	(45)
Basic and diluted weighted average number of common shareholders outstanding (millions)	**287**	288	**287**	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.30)**	(0.09)	**(0.44)**	(0.16)

D. Dividends

On Oct. 10, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2019.

On July 19, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Oct. 1, 2018.

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

E. Stock Options

The stock options granted to executive officers of the Corporation during the nine months ended Sept. 30, 2018 and 2017 are as follows:

Grant month	Number of stock options granted *(millions)*[1]		Exercise price	Vesting period *(years)*	Expiration length *(years)*
March 2018	0.6	$	7.45	3	7
March 2017	0.7	$	7.25	3	7

(1) Certain stock options were forfeited when one of the executive officers resigned.

14. 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 Sept. 30, 2018 and Dec. 31, 2017, the Corporation had 10.2 million Series A, 11.0 million Series C, 9.0 million Series E, 6.6 million Series G Cumulative Redeemable Rate Rest First Preferred Shares issued and outstanding and 1.8 million Series B Cumulative Redeemable Floating Rate First Preferred Shares issued and outstanding.

B. Dividends

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

		3 months ended Sept. 30		9 months ended Sept. 30	
Series	**Quarterly amounts per share**	**2018**	2017	**2018**	2017[1]
A	0.16931	**2**	2	**5**	3
B	0.20984[2]	**—**	—	**1**	1
C	0.25169	**2**	3	**8**	6
E	0.32463	**3**	3	**9**	6
G	0.33125	**3**	2	**7**	4
Total for period		**10**	10	**30**	20

(1) No dividends were declared in the first quarter of 2017 as on Dec. 19, 2016, the quarterly dividend related to the period covering the first quarter of 2017 was declared.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent. Approximately $400 thousand and $1.1 million of dividends were declared for the three and nine months ended Sept. 30, 2018, respectively.

On Oct. 10, 2018 the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.22301 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 Dec. 31, 2018.

15. 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.

I. Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding (the "LLRP") 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 estimate of the maximum exposure is $15 million; however, if the Corporation and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil. The Corporation has recorded a provision of $7.5 million as at Sept. 30, 2018 and Dec. 31, 2017.

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.

16. Segment Disclosures

A. Reported Segment Earnings (Loss)

I. Earnings Information

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

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

3 months ended Sept. 30, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	252	147	56	43	42	31	17	—	588
Fuel, carbon, and purchased power	154	109	24	3	2	2	—	—	294
Gross margin	98	38	32	40	40	29	17	—	294
Operations, maintenance, and administration	42	13	10	9	12	10	5	18	119
Depreciation and amortization	79	19	10	10	27	7	—	6	158
Asset impairment charge	—	—	—	—	—	—	—	—	—
Taxes, other than income taxes	3	1	—	—	2	—	—	1	7
Net other operating income	(10)	—	—	—	—	—	—	—	(10)
Operating income (loss)	(16)	5	12	21	(1)	12	12	(25)	20
Finance lease income	—	—	2	13	—	—	—	—	15
Net interest expense									(69)
Foreign exchange gain									(8)
Other income (loss)									(1)
Loss before income taxes									(43)

9 months ended Sept. 30, 2018	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**680**	**296**	**167**	**123**	**192**	**127**	**48**	**(6)**	**1,627**
Fuel, carbon, and purchased power	**490**	**186**	**70**	**6**	**13**	**5**	**—**	**(6)**	**764**
Gross margin[1]	**190**	**110**	**97**	**117**	**179**	**122**	**48**	**—**	**863**
Operations, maintenance, and administration	**127**	**44**	**36**	**28**	**38**	**27**	**17**	**59**	**376**
Depreciation and amortization	**176**	**54**	**31**	**36**	**82**	**22**	**2**	**19**	**422**
Asset impairment	**38**	**—**	**—**	**—**	**12**	**—**	**—**	**—**	**50**
Taxes, other than income taxes	**10**	**3**	**1**	**—**	**6**	**3**	**—**	**—**	**23**
Net other operating income	**(188)**	**—**	**—**	**—**	**(6)**	**—**	**—**	**—**	**(194)**
Operating income (loss)	**27**	**9**	**29**	**53**	**47**	**70**	**29**	**(78)**	**186**
Finance lease income	**—**	**—**	**7**	**—**	**—**	**—**	**—**	**—**	**7**
Net interest expense									**(200)**
Foreign exchange loss									**(15)**
Other income									**1**
Earnings before income taxes									**(21)**

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

9 months ended Sept. 30, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	750	294	209	97	188	95	36	—	1,669
Fuel, carbon, and purchased power	434	188	78	9	10	5	—	—	724
Gross margin	316	106	131	88	178	90	36	—	945
Operations, maintenance, and administration	133	37	36	22	36	27	16	64	371
Depreciation and amortization	226	50	28	24	82	24	1	20	455
Asset impairment	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	10	3	1	—	6	2	—	1	23
Net other operating income	(30)	—	—	—	—	—	—	—	(30)
Operating income (loss)	(43)	16	66	42	54	37	19	(85)	106
Finance lease income	—	—	8	39	—	—	—	—	47
Net interest expense									(190)
Foreign exchange gain									(7)
Other income (loss)									1
Loss before income taxes									(43)

B. Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Condensed Consolidated Statements of Earnings (Loss) and the Condensed Consolidated Statements of Cash Flows is presented below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2018	2017	**2018**	2017
Depreciation and amortization expense on the Condensed Consolidated Statements of Earnings	**146**	158	**422**	455
Depreciation included in fuel and purchased power	**34**	18	**101**	54
Depreciation and amortization on the Condensed Consolidated Statements of Cash Flows	**180**	176	**523**	509

17. Subsequent Events

A. TransAlta Renewables Expansion of the Kent Hills Wind Facility

On Oct. 19, 2018 TransAlta Renewables announced that the 17.25MW expansion of the wind facility at Kent Hills, in New Brunswick is now fully operational, bringing total generating capacity to 167MW. In 2017, TransAlta Renewables entered into a 17-year power purchase agreement with the New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind project.

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 Condensed Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the period ended Sept. 30, 2018:

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

0.50 times

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

Supplemental Information

		Sept. 30, 2018	December 31, 2017
Closing market price (TSX) ($)		**7.27**	7.45
Price range for the last 12 months (TSX) ($)	High	**8.18**	8.50
	Low	**6.31**	6.88
FFO before interest to adjusted interest coverage(2)(times)		**4.6**	4.3
Adjusted FFO to adjusted net debt(2)(%)		**21.3**	20.4
Adjusted net debt to comparable EBITDA(1, 2) (times)		**3.5**	3.6
Adjusted net debt to invested capital(1) (%)		**48.1**	49.5
Return on equity attributable to common shareholders(2)(%)		**(15.7)**	(10.0)
Return on capital employed(2)(%)		**2.1**	2.1
Earnings coverage(2)(times)		**0.7**	0.6
Dividend payout ratio based on FFO(1, 2)(%)		**5.9**	4.3
Dividend coverage(2)(times)		**14.1**	14.1
Dividend yield(2)(%)		**2.2**	2.1

(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.

Ratio Formulas

FFO before interest to adjusted interest coverage = FFO + interest on debt and finance lease obligations - interest income - capitalized interest / interest on debt and finance 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 finance 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 finance 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 finance 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 attributable to common shareholders / equity attributable to shareholders excluding AOCI - issued preferred shares

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

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

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

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

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

Glossary of Key Terms

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

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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