TransAlta

TransAlta Corporation
First Quarter Report for 2017

Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three months ended March 31, 2017 and 2016, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2016 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 publically accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at March 31, 2017. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated May 5, 2017. 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 (loss) in our Condensed Consolidated Statements of Earnings (Loss) for the three months ended March 31, 2017, and 2016. 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. Earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable EBITDA, Funds from Operations ("FFO"), and "Free Cash Flow" ("FCF") are Non-IFRS Measures. 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”, “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 and anticipated future financial performance; our success in executing on our growth projects; the timing of the construction and commissioning of projects under development, including major projects such as the South Hedland power project, and the conversion of our Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation, and their attendant costs and sources of funding; the retirement of Sundance Unit 1 and mothballing of Sundance Unit 2; the changes to capacity and emissions following the conversion to gas generation of Sundance Units 3 to 6 and Keephills Units 1 and 2; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; expected decommissioning costs; the section titled “2017 Outlook”, the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses, expectations relating to the dispositions of assets and the completion of sale transactions; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2017 comparable EBITDA, FFO, FCF, and expected sustaining capital expenditures); expectations in respect of financial ratios and targets and the timing associated with meeting such targets (including FFO before interest to adjusted interest coverage, adjusted FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); the Corporation’s plans and strategies relating to repositioning its capital structure and strengthening its balance sheet and the anticipated debt reductions during 2017 and beyond; expected governmental regulatory regimes, legislation (including the Government of Alberta’s Climate Leadership Plan) and proposed regulations to discontinue over time the use of technologies that our coal-fired plants currently utilize, the expected impact 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; the expected results and impact of the Off-Coal Agreement (“OCA”) and Memorandum of Understanding (“MOU”) with the Government of Alberta on our business and financial performance; the outcome of discussions with the Government of Canada and the Government of Alberta in relation to potential opportunities for investment in renewable and gas-fired generation; our comparative advantages over our competitors; estimates of fuel supply and demand conditions and the costs of procuring fuel; our share of offer control in the Province of Alberta after the expiry of the Power Purchase Arrangements (“PPAs”) at the end of 2020; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs, including the impact of the anticipated elimination of current excess system capacity and future growth in Alberta driven by the retirement of coal units over the next 15 years; expected financing of our capital expenditures; the anticipated financial impact of increased carbon prices (including under the existing Specified Gas Emitters Regulation) (“SGER”) in Alberta; expectations in respect of our environmental initiatives; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets on reasonable terms; 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; the monitoring of our exposure to liquidity risk; expectations regarding the impact of the general slowdown in the oil and gas sector; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; expected cost savings following the implementation of our efficiency and productivity initiatives; the estimated contribution of Energy Marketing activities to gross margin; 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 our upcoming debt maturities over the next two years by raising $700 million to $900 million of debt secured by contracted cash flows; expectations regarding our de-leveraging strategy, including applying a portion of our FCF over the next four years to reduce debt; expectations in respect of our community initiatives; impacts of future IFRS 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 the availability of fuel supplies required to generate electricity; 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; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; 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; 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; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays or changes in costs in the construction and commissioning of the South Hedland power project; and 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 this MD&A and under the heading “Risk Factors” in our 2017 Annual Information Form for the fiscal year ended Dec. 31, 2016.

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
Consolidated Financial Highlights

	3 months ended March 31	
	2017	2016
Revenues	**578**	568
Net earnings attributable to common shareholders	**-**	62
Cash flow from operating activities	**281**	275
Comparable EBITDA[1]	**274**	279
FFO[1]	**203**	196
FCF[1]	**98**	86
Net earnings per share attributable to common shareholders, basic and diluted	**-**	0.22
FFO per share[1]	**0.70**	0.68
FCF per share[1]	**0.34**	0.30
Dividends declared per common share	**-**	0.04

As at	March 31, 2017	Dec. 31, 2016
Total assets	**11,049**	10,996
Net debt[2]	**3,649**	3,893
Total long-term liabilities	**5,130**	5,116

For the first quarter of 2017, comparable EBITDA was $274 million, down $5 million compared with last year. As we were expecting, gross margin at Canadian Coal was impacted by hedges rolling off and being replaced with lower priced hedges and by higher mining costs. Energy Marketing was impacted by unusual weather in the Northeast and the Pacific Northwest and delivered below expected performance in the quarter. The recognition of the expected settlement in relation to the contract indexation dispute with the Ontario Electricity Financial Corporation ("OEFC") relating to the Ottawa and Windsor generating facilities totalling $34 million, almost fully offset the shortfall in Energy Marketing and Canadian Coal.

FFO and FCF were slightly higher than last year as lower comparable EBITDA was offset by higher realized foreign exchange gains and non-cash mark-to-market gains in 2017.

Reported net earnings attributable to common shareholders for the quarter was nil (nil per share) compared to net earnings of $62 million ($0.22 net earnings per share) in 2016 due to higher net earnings attributable to TransAlta Renewables shareholders. Last year net earnings in the first quarter was also positively impacted by the reduction of our reclamation obligation at our Centralia mine caused by a higher discount rate. This year, higher depreciation arose due to the shortening of useful lives of Keephills 3 and Genesee 3.

The decrease of $244 million in net debt is primarily due to strong free cash flows, a decrease in our working capital, the receipt of $61 million from the sale of the Wintering Hills merchant wind facility, and the impact of the weakening US dollar.

(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) Net debt includes current portion, amounts due under credit facilities, long-term debt, tax equity, and finance lease obligations, net of cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure and Liquidity section of this MD&A for more details on the composition of net debt.

Segmented Comparable EBITDA Results

	3 months ended March 31	
	2017	2016
Comparable EBITDA		
Canadian Coal	91	103
U.S. Coal	10	(4)
Canadian Gas	88	65
Australian Gas	31	31
Wind and Solar	68	61
Hydro	14	18
Energy Marketing	(4)	23
Corporate	(24)	(18)
Total comparable EBITDA	274	279

Significant Events

During the quarter, we continued to work on strengthening our financial flexibility, improving our operating performance, and progressing our transition to clean power generation through the following initiatives:

- Closed the previously announced sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale provides us with near-term liquidity, increases our financial flexibility, and reduces our merchant exposure in Alberta.
- Progressed the construction of the South Hedland power project. We expect the project to be fully commissioned in mid-2017. When fully commissioned, the project is expected to generate approximately $80 million of comparable EBITDA annually.
- Continued to work on our financing initiative during the quarter. Our goal is to raise $700 to $900 million in debt secured by contracted cash flows in the next 12 to 15 months, to fund the construction of South Hedland and repay senior secured debt coming due in 2018.
- Announced the acceleration of our transition to gas and renewables generation with the retirement of Sundance Unit 1, the mothballing Sundance Unit 2, and the conversion of Sundance Units 3 to 6, and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation between 2021 to 2023. The retirement of Sundance Unit 1 and mothballing of Sundance Unit 2 is not expected to have a material impact on our forecasted cash flow for 2018 and 2019.
- Progressed the expected settlement in relation to the contract indexation dispute with the OEFC. The settlement is expected to consist of a $34 million payment by the OEFC to TransAlta, of which $11 million has already been received. We have recognized the full $34 million amount in our results in the first quarter of 2017. The settlement is expected to be finalized during the second quarter.

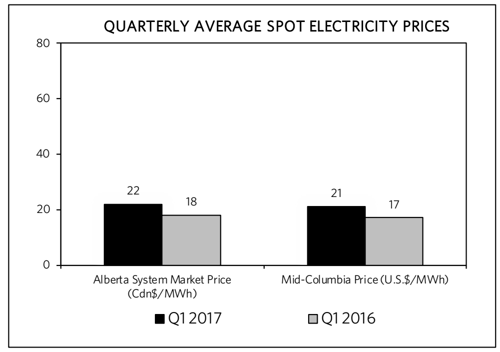
Adjusted availability and Production

Adjusted availability for the three months ended March 31, 2017 was 88.5 per cent compared to 92.3 per cent for the same period in 2016. Higher unplanned outages at Canadian and US Coal were the main cause of the decrease. Lower availability had a minimal impact on our results due to current low prices in Alberta and the Pacific Northwest.

Production for the three months ended March 31, 2017 was 9,051 gigawatt hours ("GWh"), compared to 8,867 GWh for the same period in 2016, mainly due to higher production at US Coal as a result of later economic dispatching in 2017 due to higher prices, partially offset by the cessation of operations at our Mississauga cogeneration facility, effective Jan. 1, 2017, in accordance with the terms of a new contract with Ontario's Independent Electricity System Operator ("IESO"). We continue to receive monthly capacity payments from the IESO until Dec. 31, 2018.

Electricity Prices

The average spot electricity prices for the three months ended March 31, 2017 increased compared to 2016 in both Alberta and the Pacific Northwest markets. Higher environmental levies and compliance costs have increased the marginal cost to producers in Alberta, while increased natural gas prices in the Pacific Northwest markets caused power prices to rise.



Reconciliation of Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. 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.

Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for the amount of cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. FCF is an important metric as it represents the amount of cash generated by our business, before changes in working capital, 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 as to not distort FFO and FCF with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

	3 months ended March 31	
	2017	2016
Cash flow from operating activities	281	275
Change in non-cash operating working capital balances	(95)	(94)
Cash flow from operations before changes in working capital	**186**	181
Adjustments:		
Decrease in finance lease receivable	15	14
Mississauga recontracting provision settled	1	-
Other	1	1
FFO	203	196
Deduct:		
Sustaining capital	(46)	(59)
Productivity capital	(2)	-
Dividends paid on preferred shares	(10)	(12)
Distributions paid to subsidiaries' non-controlling interests	(47)	(39)
FCF	98	86
Weighted average number of common shares outstanding in the period	288	288
FFO per share	0.70	0.68
FCF per share	0.34	0.30

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 payment we received 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 deprecation on our mining equipment from fuel and purchased power to reflect the actual cash cost of our business in our comparable EBITDA.

A reconciliation of reported Operating Income to EBITDA and comparable EBITDA results for the three months ended March 31, 2017 and 2016, are as follows:

	3 months ended March 31	
	2017	2016
Operating income	62	107
Depreciation and amortization	143	122
EBITDA	205	229
Comparable reclassifications:		
Finance leases income used as a proxy for operating revenue	16	16
Decrease in finance lease receivables used as a proxy for operating revenue	15	14
Reclassification of mine depreciation from fuel and purchased power	17	15
Adjustments to earnings to arrive at comparable results:		
Impacts to revenue associated with certain de-designated and economic hedges	-	5
Impacts associated with Mississauga recontracting(1)	21	-
Comparable EBITDA	274	279

In December 2016, we agreed to terminate our existing arrangement with the IESO relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator ("NUG") Contract effective Jan. 1, 2017. Under the new NUG Contract, we receive fixed monthly payments until December 31, 2018 with no delivery obligations. Under IFRS 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.

(1) Impacts associated with Mississauga recontracting for the first quarter of 2017 are as follows: Revenue ($27 million), fuel and purchased power de-designated hedges ($4 million), and Operations, maintenance, and administration ($2 million).

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. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items.

	3 months ended March 31	
	2017	2016
Comparable EBITDA	274	279
Provisions	1	1
Interest expense	(57)	(58)
Unrealized (gains) losses from risk management activities	(5)	(7)
Current income tax expense	(6)	(5)
Decommissioning and restoration costs settled	(4)	(3)
Realized foreign exchange gain (loss)	3	(1)
Other non-cash items	(3)	(10)
FFO	203	196
Deduct:		
Sustaining capital	(46)	(59)
Productivity capital	(2)	-
Dividends paid on preferred shares	(10)	(12)
Distributions paid to subsidiaries' non-controlling interests	(47)	(39)
FCF	98	86
Weighted average number of common shares outstanding in the period	288	288
FFO per share	0.70	0.68
FCF per share	0.34	0.30

Comparable EBITDA for the quarter totaled $274 million, down $5 million compared to last year. Even though prices in Alberta improved slightly compared to last year, the rolling off of higher priced hedges negatively impacted the results of our Canadian Coal portfolio. Also, as expected, we are facing higher coal costs in Alberta in 2017 due to an outage on one of our draglines at the mine, as well as a higher strip ratio. Our strip ratio is expected to improve as we open a new mining area in 2018. Higher levels of rainfall in the Pacific Northwest, coupled with a warmer winter in the Northeast, negatively impacted our ability to generate gross margins in our Energy Marketing business. These shortfalls in Canadian Coal and Energy Marketing were mostly offset by the expected settlement of the indexation dispute with the OEFC relating to the long-term contracts for the Ottawa and Windsor facilities.

FCF for the first quarter was up by $12 million, compared to 2016, due to higher realized foreign exchange gains, higher unrealized mark-to-market gains and, lower sustaining capital expenditures, offset by higher distributions paid to subsidiaries' non-controlling interests as a result of the expected settlement of the indexation dispute for our long-term contracts at Ottawa and Windsor, which forms part of TransAlta Cogeneration L.P ("TA Cogen").

Discussion of Segmented Comparable Results

Each business segment assumes responsibility for its operating results measured to comparable EBITDA. Operating income and gross margin are also useful measures as they provide management and investors with a measurement of operating performance that is readily comparable from period to period.

Canadian Coal

	3 months ended March 31	
	2017	2016
Availability (%)	83.7	86.6
Contract production (GWh)	4,971	4,919
Merchant production (GWh)	1,003	909
Total production (GWh)	5,974	5,828
Gross installed capacity (MW)	3,791	3,786
Revenues	250	234
Fuel and purchased power	122	83
Comparable gross margin	128	151
Operations, maintenance, and administration	44	45
Taxes, other than income taxes	3	3
Net other operating income	(10)	-
Comparable EBITDA	91	103
Depreciation and amortization	87	76
Comparable operating income	4	27
Sustaining capital:		
Routine capital	5	2
Mine capital	3	-
Finance leases	4	3
Productivity capital	1	-
Planned major maintenance	17	37
Total sustaining capital expenditures	30	42

Production for the three months ended March 31, 2017 increased 146 GWh compared to 2016. Lower availability caused by higher unplanned outages and derates was offset by lower paid curtailments on contracted assets and lower levels of economic dispatching on our non-contracted generation as a result of slightly higher prices.

Comparable EBITDA for the three months ended March 31, 2017 decreased $12 million compared to 2016. Revenues for the quarter were positively impacted by the pass through of higher environmental compliance costs to PPA buyers. Lower hedge prices on our non-contracted generation ($7 million) and changes in our mark-to-market positions attributable to long-term financial contracts to economically hedge our future generation ($5 million) partially offset the increase in our revenues. Fuel and purchased power was impacted by lower expected production volume and a higher expected strip ratio at our mine, and higher expected environmental compliance costs in 2017. Most of the higher environmental compliance costs are offset as pass through revenue. Comparable EBITDA also includes a $10 million accrual related to Off-Coal Agreement payments included in net other operating income.

Depreciation increased mainly due to the shortening of the useful lives of the Keephills 3 and Genesee 3 facilities and on mine equipment at the Sunhills Mine. See the Accounting Changes section of this MD&A for further details.

For the first quarter, sustaining capital expenditures decreased by $13 million compared to 2016, mainly due to lower planned outage expenditures. In 2016 we executed pit stops on our Sundance 1 and 2 Units as well as a large outage on Sundance Unit 4. During the first quarter of 2017, only one planned outage was performed on Sundance Unit 6.

US Coal

	3 months ended March 31	
	2017	2016
Availability (%)	54.7	100.0
Adjusted availability (%)[1]	86.7	100.0
Contract sales volume (GWh)	905	915
Merchant sales volume (GWh)	959	402
Purchased power (GWh)	(1,052)	(945)
Total production (GWh)	812	372
Gross installed capacity (MW)	1,340	1,340
Revenues	88	61
Fuel and purchased power	64	52
Comparable gross margin	24	9
Operations, maintenance, and administration	13	12
Taxes, other than income taxes	1	1
Comparable EBITDA	10	(4)
Depreciation and amortization	15	(3)
Comparable operating loss	(5)	(1)
Sustaining capital:		
Routine capital	-	1
Finance leases	1	-
Productivity capital	1	-
Planned major maintenance	5	3
Total	7	4

Availability for the three months ended March 31, 2017 was down compared to 2016, due to a forced outage on Unit 1 in January. Both Units 1 and 2 commenced economic dispatching in February as a result of seasonally lower prices in the Pacific Northwest. The lower availability had a nominal impact on our results, as due to the low prices, contractual obligations were supplied by buying less expensive power in the market.

Production was up 440 GWh during the first quarter of 2017 compared to 2016, due mainly to the timing of economic dispatching in 2017.

Comparable EBITDA increased by $14 million compared to 2016. Gross margin was up $15 million as a result of higher prices on contracted sales, higher merchant sale volumes, favourable impacts of mark-to-market positions on certain forward financial contracts that do not qualify for hedge accounting, and a reduction in coal impairment charges. The weakened Canadian dollar also contributed to the higher comparable EBITDA during the first quarter of 2017.

Depreciation and amortization for the first quarter of 2017 increased by $18 million compared to 2016, due to an adjustment in 2016 on our future obligation caused by higher discount rates being applied to our decommissioning obligation for the Centralia mine. As the mine is in the reclamation stage, the adjustment flows directly to earnings. This adjustment reversed in the second quarter of 2016.

Sustaining capital expenditures for the first quarter of 2017 were up $2 million compared to 2016, primarily due to increased scope work on Unit 1, caused by the forced outage.

(1) Adjusted for economic dispatching.

Canadian Gas

	3 months ended March 31	
	2017	2016
Availability (%)	100.0	99.4
Contract production (GWh)	393	743
Merchant production (GWh)	44	-
Total production (GWh)	437	743
Gross installed capacity (MW)[1]	953	1,057
Revenues	146	122
Fuel and purchased power	43	42
Comparable gross margin	103	80
Operations, maintenance, and administration	14	14
Taxes, other than income taxes	1	1
Comparable EBITDA	88	65
Depreciation and amortization	29	28
Comparable operating income	59	37
Sustaining capital:		
Planned major maintenance	3	2
Total	3	2

Production for the first quarter of 2017 decreased 306 GWh compared to 2016, primarily due to the Windsor and Mississauga plant recontracting. The Windsor facility has been operating under a new capacity contract effective Dec. 1, 2016, and the Mississauga plant facility has been temporarily shut down effective Jan. 1, 2017, as we have no delivery obligations under the new NUG Contract.

Comparable EBITDA for the first quarter of 2017 increased by $23 million compared to 2016, mainly due to the expected settlement of the indexation dispute for our long-term contracts at Ottawa and Windsor, partially offset by lower realized hedge gains and higher mark-to-market losses as well as lower revenues from our Windsor facility under its new contract. Mississauga, Ottawa, and Windsor generating facilities are owned through our 51 per cent interest in TA Cogen.

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. The portion of the Poplar Creek facility we continue to own and excludes the Mississauga cogeneration facility, which has been shutdown temporarily due to the recontracting in the fourth quarter of 2016.

Australian Gas

	3 months ended March 31	
	2017	2016
Availability (%)	89.9	90.1
Contract production (GWh)	398	372
Gross installed capacity (MW)[1]	425	348
Revenues	40	42
Fuel and purchased power	2	5
Comparable gross margin	38	37
Operations, maintenance, and administration	7	6
Comparable EBITDA	31	31
Depreciation and amortization	8	5
Comparable operating income	23	26
Sustaining capital:		
Routine capital	-	1
Planned major maintenance	1	-
Total	1	1

Production for the first quarter of 2017 increased 26 GWh compared to 2016, mostly due to an increase in customer load. Due to the nature of our contracts, the increase did not have a significant financial impact on our results as our contracts are structured as capacity payments with a pass-through of fuel costs.

Depreciation and amortization for the first quarter of 2017 increased by $3 million compared to 2016, due mostly to the commissioning of a gas turbine at our South Hedland project in late December 2016. The two other gas and steam turbines will be commissioned by mid-2017.

(1) Includes production capacity for the Solomon power station, which has been accounted for as a finance lease.

Wind and Solar

	3 months ended March 31	
	2017	2016
Availability (%)	**96.4**	96.8
Contract production (GWh)	**742**	711
Merchant production (GWh)	**313**	420
Total production (GWh)	**1,055**	1,131
Gross installed capacity (MW)	**1,363**	1,424
Revenues	**87**	84
Fuel and purchased power	**5**	9
Comparable gross margin	**82**	75
Operations, maintenance, and administration	**12**	12
Taxes, other than income taxes	**2**	2
Comparable EBITDA	**68**	61
Depreciation and amortization	**27**	30
Comparable operating income	**41**	31
Sustaining capital:		
Planned major maintenance	**3**	2
Total sustaining capital expenditures	**3**	2

Production for the first quarter of 2017 decreased by 76 GWh compared to 2016, mainly due to lower wind resources impacting generation across Western Canada and the sale of the Wintering Hills merchant facility on March 1, 2017. This was partially offset by higher wind resources in Eastern Canada and in the US.

Comparable EBITDA for the first quarter of 2017 increased $7 million compared to 2016, primarily due to the sale of Solar Renewable Energy Credits ("SRECs") generated from our US Solar assets. In the first quarter of 2016, the SRECs that we sold had been acquired at fair value as part of the acquisition in the fourth quarter of 2015 and recognized as inventory in 2015. In the first quarter of 2017, sales of SRECs were internally generated with no cost in inventory. Also impacting our results this quarter are slightly better prices in Alberta on our non-contracted generation and indexation of our contracts in Eastern Canada.

Depreciation and amortization was lower by $3 million in the first quarter of 2017 compared to 2016, due to the disposition of our Wintering Hills merchant wind facility, which closed on March 1, 2017.

Hydro

	3 months ended March 31	
	2017	2016
Contract production (GWh)	367	417
Merchant production (GWh)	8	4
Total production (GWh)	375	421
Gross installed capacity (MW)	926	926
Revenues	24	28
Fuel and purchased power	1	2
Comparable gross margin	23	26
Operations, maintenance, and administration	8	7
Taxes, other than income taxes	1	1
Comparable EBITDA	14	18
Depreciation and amortization	8	7
Comparable operating income	6	11
Sustaining capital:		
Routine capital, excluding hydro life extension	1	-
Hydro life extension	-	3
Planned major maintenance	1	2
Total	2	5

Production for the first quarter of 2017 decreased by 46 GWh compared to 2016, primarily due to lower water resources. Lower generation negatively impacted our results.

Comparable EBITDA for the first quarter of 2017 decreased by $4 million compared to 2016. The first quarter of 2016 results included a prior year adjustment for metering at one of our hydro power plants.

Sustaining capital for the first quarter of 2017 decreased $3 million compared to 2016, due to life extension projects at Bighorn and Brazeau last year.

Energy Marketing

	3 months ended March 31	
	2017	2016
Revenues and comparable gross margin	1	32
Operations, maintenance, and administration	5	9
Comparable EBITDA	(4)	23
Depreciation and amortization	-	1
Comparable operating income	(4)	22

For the three months ended March 31, 2017, comparable EBITDA decreased by $26 million compared to 2016, due to warm weather during the winter in the Northeast, significant precipitation in the Pacific Northwest, and reduced volume of activities in the quarter due to reduced risk taken by the traders facing uncertain conditions, and from our customer risk management activity business.

Corporate

Our Corporate overhead costs of $24 million were $6 million higher in the first quarter of 2017 compared to 2016, primarily due to a reclassification of incentives for 2016 between our operational segments and corporate segment.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined 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	March 31, 2017(1)	Dec. 31, 2016
FFO	770	763
Add: Interest on debt net of capitalized interest	222	223
FFO before interest	**992**	986
Interest on debt	238	239
Add: 50 per cent of dividends paid on preferred shares	20	21
Adjusted interest	**258**	260
FFO before interest to adjusted interest coverage (times)	**3.8**	3.8

Our target for FFO before interest to adjusted interest coverage is four to five times. The ratio is comparable to 2016. We expect this metric to improve towards our targeted level once our South Hedland power project is commissioned in mid-2017.

Adjusted FFO to Adjusted Net Debt

As at	March 31, 2017	Dec. 31, 2016
FFO(1)	770	763
Less: 50 per cent of dividends paid on preferred shares(1)	(20)	(21)
Adjusted FFO(1)	**750**	742
Period-end long-term debt(2)	4,304	4,361
Less: Cash and cash equivalents	(504)	(305)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of economic hedging instruments on debt(3)	(151)	(163)
Adjusted net debt	**4,120**	4,364
Adjusted FFO to adjusted net debt (%)	**18.2**	17.0

Our adjusted FFO to adjusted net debt ratio improved to 18.2 per cent, due to the reduction of our net debt in the first quarter. We expect this metric to improve towards our targeted level of 20 to 25 per cent once our South Hedland power project is commissioned in mid-2017.

(1) Last 12 months. Our target range for comparable FFO in 2017 is $765 million to $855 million.
(2) Includes finance lease obligations and tax equity financing.
(3) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at March 31, 2017 and Dec. 31, 2016. During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Adjusted Net Debt to Comparable EBITDA

As at	March 31, 2017	Dec. 31, 2016
Period-end long-term debt[1]	4,304	4,361
Less: Cash and cash equivalents	(504)	(305)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of economic hedging instruments on debt[2]	(151)	(163)
Adjusted net debt	4,120	4,364
Comparable EBITDA	1,140	1,145
Adjusted net debt to comparable EBITDA (times)	3.6	3.8

During the first quarter of 2017, our adjusted net debt to comparable EBITDA ratio improved compared to 2016, mainly due to the significant reduction during the quarter of our net debt. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. We expect this metric to trend towards our targeted level due to the expected increase in comparable EBITDA of approximately $80 million annually from the South Hedland power project, once commissioned in mid-2017.

Significant and Subsequent Events

Transition to Clean Power in Alberta

On April 19, 2017, we announced our strategy to accelerate our transition to gas and renewables generation. The strategy includes the following steps:

- retirement of Sundance Unit 1 effective Jan. 1, 2018;
- mothballing of Sundance Unit 2 effective Jan. 1, 2018, for a period of 2 years; and
- conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2023 timeframe, thereby extending the useful lives of these units until the mid-2030's.

The retirement of Sundance Unit 1 and mothballing of Sundance Unit 2 reflects the limited economic viability of the units upon the expiry of their PPA due to the current oversupplied Alberta power market and low power price environment and is not expected to materially impact our forecasted cash flows for 2018 and 2019.

The benefits of converting coal-fired units to gas-fired generation include:

- significantly lowering carbon intensities, emissions, and carbon costs;
- significantly lowering operating and sustaining capital costs;
- increasing operating flexibility; and
- adding between five-to-ten years of economic life to each converted unit.

Sundance Units 1 and 2

Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, we intend to apply to the federal Minister of Environment to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide us with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively comprise 560 MW of the 2,141 MW at the Sundance power plants, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expires on Dec. 31, 2017.

(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 March 31, 2017 and Dec. 31, 2016. During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Coal-to-Gas Conversions

We expect that the capacity of Sundance Units 3 to 6 and Keephills 1 and 2 will not change following conversion, which will result in a reduction of approximately 40 per cent of carbon emissions while maintaining approximately 2,400 MWs in the Alberta power grid.

Our total capital commitment for the coal-to-gas conversions is expected to be approximately $300 million, mostly invested between 2021 to 2023. We anticipate funding the conversions with free cash flow at that time. These units are expected to provide low cost capacity and to be competitive in the upcoming capacity market auctions; we expect the first auction to occur in 2019 for 2021 and that Federal and Provincial regulations will be adopted to facilitate coal-to-gas conversions. We continue to be engaged with government in the development of the required regulatory regime.

Alberta Off-Coal Agreement

On Nov. 24, 2016, we announced that we entered into the OCA with the Government of Alberta on transition payments in exchange 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, we will receive annual cash payments on or before July 31 of approximately $39.9 million ($37.4 million, net to the Corporation), commencing Jan. 1, 2017 and terminating at the end of 2030. We recognize the OCA payments evenly throughout the year. Accordingly, during the three months ended March 31, 2017, approximately $10 million was recognized in Net Other Operating Income in the Condensed Consolidated Statement of Earnings. 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 the combustion of coal.

Mississauga Cogeneration Facility New Contract

On Dec. 22, 2016, we announced that we had signed a NUG Contract with the Independent Electricity System Operator for our Mississauga cogeneration facility. The NUG Contract became effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, we agreed to terminate effective Dec. 31, 2016, the Mississauga cogeneration facility's pre-existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. The NUG Contract provides us stable monthly payments totalling approximately $209 million until Dec. 31, 2018.

Refer to our 2016 Annual MD&A for further information regarding the Mississauga NUG Contract.

Wintering Hills Sale

On March 1, 2017, we closed the previously announced sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. Proceeds from the sale will be used for general corporate purposes, including reducing our debt and funding future renewables growth.

Credit Ratings Change

The Corporation maintains investment grade ratings from three credit rating agencies.

On March 15, 2017, Fitch Ratings reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable.

On April 3, 2017, DBRS Limited changed our Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating BBB to BBB (low).

On April 11, 2017, Standard and Poor's reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- but changed the outlook from stable to negative.

Environmental Regulation Updates

Refer to the Regional Regulation and Compliance discussion in our 2016 Annual MD&A for further details that supplement the recent developments as discussed below.

Alberta

In March 2016, Alberta began development of its renewable energy procurement process design for the Alberta Electric System Operator ("AESO") to procure a first block of renewable generation projects to be in-service by 2019. On Sept. 14, 2016, the Government of Alberta re-confirmed its commitment to achieve 30 per cent renewables in Alberta's electricity energy mix by 2030. On March 31, 2017, the AESO launched its procurement process which requested expression of interests from qualified bidders. The successful bidders will be announced in December 2019.

Ontario

On Feb. 25, 2016, Ontario released draft regulations for its GHG cap-and-trade program that were finalized on May 19, 2016. The regulations became effective Jan. 1, 2017, and will apply to all fossil fuels used for electricity generation. The majority of our gas-fired generation in Ontario will not be significantly impacted by virtue of change-in-law provisions within existing PPAs.

Capital Structure and Liquidity

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

	March 31, 2017		Dec. 31, 2016	
	$	%	$	%
Recourse debt - CAD debentures	1,045	13	1,045	12
Recourse debt - U.S. senior notes	2,116	26	2,151	25
U.S. tax equity financing	37	-	39	1
Other	15	-	15	-
Less: cash and cash equivalents	(504)	(6)	(305)	(4)
Less: fair value asset of economic hedging instruments on debt[1]	(151)	(2)	(163)	(2)
Net recourse debt	2,558	31	2,782	32
Non-recourse debt	1,023	12	1,038	12
Finance lease obligations	68	1	73	1
Total net debt	3,649	44	3,893	45
Non-controlling interests	1,142	14	1,152	14
Equity attributable to shareholders				
Common shares	3,094	37	3,094	36
Preferred shares	942	11	942	11
Contributed surplus, deficit, and accumulated other comprehensive income	(499)	(6)	(525)	(6)
Total capital	8,328	100	8,556	100

On Jan. 18, 2017, we filed a US base shelf prospectus that allows for the issuance of up to $2.0 billion aggregate principal amount (or its equivalent in other currencies) of common shares, first preferred shares, warrants, subscription receipts and debt securities from time to time. The specific terms of any offering of securities is to be determined at the date of issue.

We continued to strengthen our financial position during the first quarter of 2017 and reduced our total net debt by $244 million, due to the higher FCF generated during the first quarter and the reduction of our working capital.

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

The weakening of the US dollar has decreased our long-term debt balances by $35 million compared to Dec. 31, 2016. Almost all our U.S.-denominated debt is hedged(1) either through financial contracts or net investments in our U.S. operations. During the period, these changes in our U.S.-denominated debt were offset as follows:

As at	March 31, 2017	Dec. 31, 2016
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	(18)	(35)
Foreign currency economic cash flow hedges on debt	(16)	(29)
Economic hedges and other	(1)	(3)
Total	(35)	(67)

During the period through Dec. 31, 2020, we have approximately $2.5 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising $700 million to $900 million of debt secured by our contracted cash flows over the next 12 to 15 months. We also expect to continue our deleveraging strategy, as a significant part of our FCF over the next four years will be allocated to debt reduction.

Our credit facilities provide us with significant liquidity. At March 31, 2017, we had a total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities, of which $1.4 billion (Dec. 31, 2016 - $1.4 billion) was available for use. We are in compliance with the terms of the credit facilities. At March 31, 2017, the $0.6 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility expiring in 2020, one bilateral credit facility of US$200 million, expiring in 2018, and three bilateral credit facilities, totalling $240 million, expiring in 2020.

Other non-recourse debt of $830 million in total (Dec. 31, 2016 - $845 million) is subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by certain 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 restrictions include the ability to meet a debt service coverage ratio prior to distribution. This test was not met by one of our subsidiaries, New Richmond Wind L.P. in the first quarter of 2017, mainly due to annualization of its results for purposes of the test. The funds in this entity will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2017. At March 31, 2017, $44 million (Dec. 31, 2016 - $24 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts are established and funded through cash held on deposit and/or by providing letters of credit. As part of our cost reduction initiatives to reduce fees associated with letters of credit, we have elected to fund through cash. Accordingly, as at March 31, 2017, $16 million of cash was on deposit for certain reserves and was not available for general use.

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Share Capital

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

As at	May 4, 2017	March 31, 2017	Dec. 31, 2016
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	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 March 31, 2017, we own 64.0 per cent (Dec. 31, 2016 – 64.0 per cent) of TransAlta Renewables. The stable and predictable cash flows generated by TransAlta Renewables' assets has attracted favourable equity valuations from investors, allowing TransAlta to raise equity capital. 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.

We also own 50.01 per cent of TransAlta Cogen which owns, operates, or has an interest in four natural-gas-fired facilities and a 50 per cent interest in a coal-fired generating facility.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended March 31	
	2017	2016
Interest on debt	56	57
Interest income	(1)	(1)
Capitalized interest	(3)	(3)
Interest on finance lease obligations	1	1
Other[1]	4	4
Accretion of provisions	5	6
Net interest expense	62	64

Net interest expense decreased during the first quarter of 2017 compared to 2016. Higher interest on long term debt was offset by favourable impacts of foreign exchange rates.

Dividends to Shareholders

On Dec. 19, 2016, the Board declared quarterly dividends per common share and preferred shares payable to shareholders relating to the period covering the first quarter of 2017. A total of $12 million and $10 million in common and preferred share dividends were paid during the quarter, respectively.

(1) 2016 includes interest accrued related to the Keephills 1 outage arbitration.

On April 19, 2017, we declared a dividend of $0.04 per common share, payable on July 1, 2017. We also declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.15645 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on June 30, 2017.

Non-Controlling Interests

Reported earnings attributable to non-controlling interests for the first quarter of 2017 increased to $28 million from a net loss of $3 million from the first quarter of 2016, due to higher earnings at TransAlta Renewables resulting from a favourable reduction in unrealized foreign exchange losses on some of its financial interests in the Australian Assets.

Other Consolidated Analysis

Financial Position

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2016 to March 31, 2017:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	199	Proceeds from sale of our Wintering Hills merchant wind facility, strong free cash flow, and timing of receipts and payments
Trade and other receivables	(46)	Timing of customer receipts and seasonality of revenue
Prepaid expenses	25	Timing of payments of insurance, deposits, and other prepayments
Assets held for sale	(61)	Closing of the sale of the Wintering Hills merchant wind facility
Risk management assets (current and long term)	24	Favourable market price movements, partially offset by contract settlements and unfavourable changes in foreign exchange rates
Other assets	(30)	Transfer of portion of Mississauga recontracting receivable to current assets
Other	(58)	
Total decrease in assets	**53**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	44	Timing of payments and accruals
Dividends payable	(21)	Timing of the declaration of common dividends
Credit facilities, long term debt, and finance lease obligations (including current portion)	(57)	Favourable effects of changes in foreign exchange rates ($35 million) and repayments ($14 million)
Decommissioning and other provisions (current and long term)	63	Impact of lower discount rate due to shortened useful lives on certain Alberta coal assets
Risk management liabilities (current and long term)	21	New contracts entered into during the period and unfavourable changes in foreign exchange rates
Equity attributable to shareholders	26	Gains on cash flow hedges ($15 million), gains on translating net assets of foreign operations ($7 million), partially offset by net loss ($10 million)
Non-controlling interests	(10)	Distributions paid, partially offset by earnings
Other	(13)	
Total decrease in liabilities and equity	**53**	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2017 compared to the same period in 2016:

3 months ended March 31	2017	2016	Increase/ (decrease	Primary factors explaining change
Cash and cash equivalents, beginning of period	**305**	54	251	
Provided by (used in):				
Operating activities	**281**	275	6	Increase in cash earnings
Investing activities	**5**	(67)	72	Higher proceeds on disposition of facilities ($61 million), lower additions to PP&E, including assets under construction ($25 million), partially offset by unfavourable changes in investing working capital ($9 million)
Financing activities	**(88)**	(230)	142	Lower repayment of credit facilities ($315 million) and lower dividends paid on common shares ($22 million), partially offset by lower net proceeds on sale of non-controlling interest in subsidiary ($162 million) and lower issuance of long-term debt ($17 million)
Translation of foreign currency cash	**1**	(2)	3	
Cash and cash equivalents, end of period	**504**	30	474	

Unconsolidated Structured Entities or Arrangements

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

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At March 31, 2017, we provided letters of credit totalling $556 million (Dec. 31, 2016 - $566 million) and cash collateral of $86 million (Dec. 31, 2016 - $77 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.

Commitments

During the first quarter of 2017, we extended and revised our existing agreement with Alstom to provide major maintenance for our Canadian Coal facilities. The agreement relates to major maintenance projects over the 2017 through 2020 years at our Keephills plants and on some Sundance plants. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

Contingencies

I. Line Loss Rule Proceeding

TransAlta is participating in a line loss rule proceeding (the "LLRP") that is currently before the Alberta Utilities Commission ("AUC"). The AUC has determined that it has the ability to retroactively adjust line loss rates going back to 2006 and directed the Alberta Electric System Operator (the "AESO") to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. TransAlta may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP, however, currently remains uncertain and the total potential exposure faced by TransAlta, if any, cannot be calculated with certainty until retroactive calculations using an AUC-approved methodology are made available, and until the AUC determines what methodology will be used for retroactive calculations. The AESO expects retroactive calculations for each year using an AUC-approved methodology to begin to be available in the second quarter of 2017, at the earliest.

As a result, no provision has been recorded at this time. Further, certain PPAs for TransAlta's facilities provide for the pass through of these types of transmission charges to TransAlta's buyers.

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2016 Annual Integrated Report and Note 8 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2017 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2016 Annual Integrated Report and Note 9 of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2016.

During the first quarter of 2017, we discontinued hedge accounting for certain foreign currency cash flow and fair value hedges on US$690 million and US$50 million of debt, respectively. As at March 31, 2017, cumulative gains on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income ("AOCI") and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. As at March 31, 2017, cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt's maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

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

As at March 31, 2017, total Level III financial instruments had a net asset carrying value of $784 million (Dec. 31, 2016 - $758 million net asset). The increase during the period is primarily due to the 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.

2017 Financial Outlook

The following table outlines our expectations on key financial targets for 2017:

Measure	Target
Comparable EBITDA	$1,025 million to $1,135 million
Comparable FFO	$765 million to $855 million
Comparable FCF	$300 million to $365 million
Coal fleet availability	86 to 88 per cent
Dividend	$0.16 per common share annualized, 13 to 15 per cent payout of FCF

Prices

For the remainder of 2017, power prices in Alberta are expected to be slightly better than 2016 as a result of higher natural gas prices and incremental carbon costs that increase the variable cost of generation year-over-year. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, power prices will be lower for the second quarter due to a strong hydro season, however, for third and fourth quarters, prices are expected to be comparable to 2016.

Contractual Profile

As a result of Alberta PPAs and long-term contracts, approximately 80 per cent of our capacity is contracted over the next two years. With the announced closure of Sundance Unit 1 and the mothballing of Sundance Unit 2, this level of contracted capacity is relatively stable until the end of 2020 when the PPA's on our Alberta coal fleet end. More than half of our non-contracted generation is sold forward 12 to 18 months ahead of time using short-term physical or financial contracts, such that on an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming calendar year. As at the end of the first quarter of 2017, approximately 86 per cent of our 2017 capacity was contracted. The average prices of our short-term physical and financial contracts for 2017 are approximately $45 per MWh in Alberta and approximately US$45 per MWh in the Pacific Northwest.

Availability

Availability of our coal fleet is expected to be at the low end of our range of 86 to 88 per cent in 2017. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent.

Fuel Costs

As disclosed previously, the cost to mine coal at our Alberta mine is expected to increase due to a major outage of a dragline and a higher strip ratio in 2017. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2017, on a standard cost per tonne basis, are expected to be approximately 12 per cent higher than 2016 unit costs. Results in the first quarter were in line with our expectations. The development of Pit 9 in 2018 is expected to improve our strip ratio.

In the Pacific Northwest, our U.S. Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost will decrease slightly in 2017 primarily due to lower transportation costs resulting from lower expected natural gas prices.

Most of our generation from gas is sold under contract with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from third parties 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

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 exposures to maximize earnings while still maintaining an acceptable risk profile. Our 2017 objective for Energy Marketing is for the segment to contribute between $60 million to $70 million in gross margin for the year, below our initial target of $70 million to $90 million, due to our first quarter performance.

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 have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2017 is expected to be higher than in 2016, largely due to lower capitalized interest. 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 $2.0 billion in liquidity, and more than $500 million in cash. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in the second quarter of 2017, and 2018.

Capital Expenditures

Our major 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		2017	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
South Hedland power project[2]	576	356	210 - 230	Q2 2017	150 MW combined-cycle power plant
Solomon load bank facility	5	2	3	Q1 2017	Installation of 20MW load bank facility required to support the operation of the Solomon power station
Transmission	Not applicable[3]		3	Ongoing	Regulated transmission that receives a return on investment
Total	**581**	**358**	**216 - 236**		

Cash required to fund the construction of the South Hedland power project is expected to be partially funded by proceeds from project financing and cash generated by our business.

(1) Represents amounts spent as of March 31, 2017.

(2) Estimated project expenditures are AUD$553 million. Total estimated project expenditures are stated in CAD$ and include estimated capital interest costs. The total estimated project expenditures may change due to fluctuations in foreign exchange rates. Approximately $155 million in project expenditures relate to infrastructure acquisition and network, water and gas access deposits, and prepayments, most of which is due to be paid on commissioning.

(3) Transmission projects are aggregated and developed on an ongoing basis. Consequently, discrete project expenditures are not available.

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 Property, plant and equipment ("PP&E") and are amortized either on a straight-line basis over the term until the next major maintenance event or on a unit-of-production basis. These costs exclude 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 2017
Routine capital[(2)]	Capital required to maintain our existing generating capacity	9	85 - 90
Planned major maintenance	Regularly scheduled major maintenance	30	125 - 130
Mine capital	Capital related to mining equipment and land purchases	3	30 - 35
Finance leases	Payments on finance leases	4	20 - 25
Total sustaining capital		46	260 - 280
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	2	10 - 15
Total sustaining and productivity capital		48	270 - 295

Significant planned major outages for 2017 include the following:

- six major outages, including: Sundance 6 outage which was completed on schedule and on budget in the first quarter, a major turnaround at Centralia Unit 2 which is currently in progress, a major outage at Keephills 2 which we are currently executing, a turnaround on Keephills 3 in the third quarter, Sheerness 1 in the fourth quarter, and a major overhaul to one of our draglines at our Highvale mine,
- three major outages in our Canadian Gas segment related to our Sarnia and Windsor facilities, scheduled for the second and fourth quarter.

Lost production as a result of planned major maintenance, excluding planned major maintenance for U.S. Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2017:

	Coal	Gas and Renewables	Total	Lost to date[(1)]
GWh lost	895 - 905	200 - 230	1,095 - 1,135	330

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 $2.0 billion in liquidity, if required. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

(1) As at March 31, 2017.
(2) Includes hydro life extension spend.

Accounting Changes

A. Current Accounting Changes

I. Change in Estimates – Useful Lives

As a result of the Alberta OCA described in the Significant Events section of this MD&A and in our 2016 annual consolidated financial statements, we will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the three months ended March 31, 2017 increased by approximately $14 million and the full year 2017 depreciation and amortization expense are expected to increase by approximately $58 million. The useful lives may be revised or extended in compliance with our 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 us, include IFRS 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers,* and IFRS 16 *Leases*. Refer to *Note 3* of our 2016 annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16.

We have made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on our financial statements and disclosures. Our current estimate of the time and effort necessary to complete the implementation plan for IFRS 9 extends into mid-to-late 2017.

We have created an implementation plan for IFRS 15 and are currently in the process of reviewing our various revenue streams and underlying contracts with customers to determine the impact that the adoption of IFRS 15 will have on our financial statements. Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid-to-late 2017. We anticipate finalizing a decision with respect to our transition method by mid-2017.

We are in the process of completing our initial scoping assessment on IFRS 16 and expect to have an implementation plan in place by mid-2017. We anticipate most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

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

	Q2 2016	Q3 2016	Q4 2016	**Q1 2017**
Revenues	492	620	717	**578**
Comparable EBITDA	248	244	374	**274**
Comparable FFO	175	163	228	**203**
Net earnings (loss) attributable to common shareholders	6	(12)	61	**-**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.02	(0.04)	0.21	**-**

	Q2 2015	Q3 2015	Q4 2015	Q1 2016
Revenues	438	641	595	568
Comparable EBITDA	183	219	268	279
Comparable FFO	160	126	243	196
Net earnings (loss) attributable to common shareholders	(131)	154	(7)	62
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.47)	0.55	(0.02)	0.22

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

Reported net earnings, comparable EBITDA, and FFO are generally higher in the first and fourth quarters due to higher demand associated with 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:
- gain on disposal of assets, following the Poplar Creek contract restructuring in the third quarter of 2015,
- U.S. Solar and Wind acquisitions in the third quarter of 2015,
- settlement with the Market Surveillance Administrator in the third quarter of 2015,
- a recovery of a writedown of deferred tax assets in, the third quarter of 2015, and the first and second quarters of 2016,
- change in income tax rates in Alberta in the second quarter of 2015,
- deferred income tax impacts of the sale of an economic interest in Australian Assets to TransAlta Renewables in the first and second quarters of 2015,
- effects of unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first, second, and third quarters of 2016, and unrealized gains in the first quarter of 2017,
- effects of the Mississauga cogeneration facility recontracting during the fourth quarter of 2016,
- effects of the Keephills 1 outage provision, and
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and 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 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 changes in our internal control over financial reporting during the three months ended March 31, 2017 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 Chief Financial Officer have concluded that, as at March 31, 2017, 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 March 31	
Unaudited	**2017**	2016
Revenues	**578**	568
Fuel, purchased power, and other	**250**	208
Gross margin	**328**	360
Operations, maintenance, and administration	**125**	123
Depreciation and amortization	**143**	122
Taxes, other than income taxes	**8**	8
Net other operating income *(Note 4)*	**(10)**	-
Operating income	**62**	107
Finance lease income	**16**	16
Net interest expense *(Note 5)*	**(62)**	(64)
Foreign exchange losses	**(1)**	(6)
Earnings before income taxes	**15**	53
Income tax recovery *(Note 6)*	**(17)**	(18)
Net earnings	**32**	71
Net earnings (loss) attributable to:		
TransAlta shareholders	**-**	74
Non-controlling interests *(Note 7)*	**32**	(3)
	32	71
Net earnings attributable to TransAlta shareholders	**-**	74
Preferred share dividends *(Note 13)*	**-**	12
Net income attributable to common shareholders	**-**	62
Weighted average number of common shares outstanding in the period *(millions)*	**288**	288
Net earnings per share attributable to common shareholders, basic and diluted	**-**	0.22

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

Unaudited	3 months ended March 31 2017	2016
Net earnings	32	71
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	1	(20)
Total items that will not be reclassified subsequently to net earnings	1	(20)
Losses on translating net assets of foreign operations[2]	(6)	(124)
Gains on financial instruments designated as hedges of foreign operations, net of tax[3]	13	62
Gains on derivatives designated as cash flow hedges, net of tax[4]	29	8
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax[5]	(6)	38
Total items that will be reclassified subsequently to net earnings	30	(16)
Other comprehensive income (loss)	31	(36)
Total comprehensive income	63	35
Total comprehensive income attributable to:		
TransAlta shareholders	26	35
Non-controlling interests *(Note 7)*	37	-
	63	35

(1) Net of income tax expense of nil for the three months ended March 31, 2017 (2016 - 7 recovery).

(2) Net of income tax recovery of 1 for the three months ended March 31, 2017 (2016 - 10 expense).

(3) Net of income tax expense of 1 for the three months ended March 31, 2017 (2016 - 4 expense).

(4) Net of income tax expense of 22 for the three months ended March 31, 2017 (2016 - 25 expense).

(5) Net of income tax expense of 11 for the three months ended March 31, 2017 (2016 - 3 recovery).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	March 31, 2017	Dec. 31, 2016
Cash and cash equivalents	504	305
Trade and other receivables *(Note 9)*	657	703
Prepaid expenses	48	23
Risk management assets *(Notes 8 and 9)*	285	249
Inventory	198	213
Assets held for sale *(Note 3)*	-	61
	1,692	1,554
Long-term portion of finance lease receivables	697	719
Property, plant, and equipment *(Note 10)*		
Cost	12,880	12,773
Accumulated depreciation	(6,069)	(5,949)
	6,811	6,824
Goodwill	464	464
Intangible assets	347	355
Deferred income tax assets	53	53
Risk management assets *(Notes 8 and 9)*	773	785
Other assets	212	242
Total assets	11,049	10,996
Accounts payable and accrued liabilities	457	413
Current portion of decommissioning and other provisions	36	39
Risk management liabilities *(Notes 8 and 9)*	75	66
Income taxes payable	9	6
Dividends payable *(Note 12)*	33	54
Current portion of long-term debt and finance lease obligations *(Note 11)*	630	639
	1,240	1,217
Credit facilities, long-term debt, and finance lease obligations *(Note 11)*	3,674	3,722
Decommissioning and other provisions	370	304
Deferred income tax liabilities	704	712
Risk management liabilities *(Notes 8 and 9)*	60	48
Defined benefit obligation and other long-term liabilities	322	330
Equity		
Common shares *(Note 12)*	3,094	3,094
Preferred shares *(Note 13)*	942	942
Contributed surplus	9	9
Deficit	(933)	(933)
Accumulated other comprehensive income	425	399
Equity attributable to shareholders	3,537	3,511
Non-controlling interests *(Note 7)*	1,142	1,152
Total equity	4,679	4,663
Total liabilities and equity	11,049	10,996

Commitments and contingencies *(Note 14)*

Subsequent events *(Note 16)*

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

3 months ended March 31, 2017

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Equity attributable to shareholders	Non-controlling interests	Total
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings	-	-	-	-	-	-	32	32
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	7	7	-	7
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	18	18	5	23
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	1	1	-	1
Total comprehensive income				-	26	26	37	63
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(47)	(47)
Balance, March 31, 2017	**3,094**	**942**	**9**	**(933)**	**425**	**3,537**	**1,142**	**4,679**

See accompanying notes.

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings (loss)	-	-	-	74	-	74	(3)	71
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(62)	(62)	-	(62)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	43	43	3	46
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(20)	(20)	-	(20)
Total comprehensive income (loss)				74	(39)	35	-	35
Common share dividends	-	-	-	(12)	-	(12)	-	(12)
Preferred share dividends	-	-	-	(12)	-	(12)	-	(12)
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	-	-	-	(12)	-	(12)	176	164
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(41)	(41)
Common shares issued	18	-	-	-	-	18	-	18
Balance, March 31, 2016	3,093	942	9	(980)	314	3,378	1,164	4,542

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	2017	2016
Operating activities		
Net earnings	32	71
Depreciation and amortization *(Note 15)*	160	136
Accretion of provisions	6	6
Decommissioning and restoration costs settled	(4)	(3)
Deferred income tax recovery *(Note 5)*	(23)	(23)
Unrealized gains from risk management activities	(5)	(2)
Unrealized foreign exchange losses	2	5
Provisions	-	1
Other non-cash items	18	(10)
Cash flow from operations before changes in working capital	186	181
Change in non-cash operating working capital balances	95	94
Cash flow from operating activities	281	275
Investing activities		
Additions to property, plant, and equipment *(Note 10)*	(60)	(85)
Additions to intangibles	(4)	(4)
Proceeds on sale of property, plant, and equipment	-	1
Proceeds on sale of facility (Wintering Hills) *(Note 3)*	61	-
Realized gains on financial instruments	-	2
Decrease in finance lease receivable	15	14
Other	(2)	1
Change in non-cash investing working capital balances	(5)	4
Cash flow (used in) from investing activities	5	(67)
Financing activities		
Net decrease in borrowings under credit facilities	-	(315)
Repayment of long-term debt	(14)	(7)
Issuance of long-term debt	-	17
Dividends paid on common shares *(Note 12)*	(12)	(34)
Dividends paid on preferred shares *(Note 13)*	(10)	(12)
Net proceeds on sale of non-controlling interest in subsidiary	-	162
Distributions paid to subsidiaries' non-controlling interests *(Note 7)*	(47)	(39)
Decrease in finance lease obligation	(4)	(3)
Other	(1)	1
Cash flow used in financing activities	(88)	(230)
Cash flow from (used in) operating, investing, and financing activities	198	(22)
Effect of translation on foreign currency cash	1	(2)
Increase (decrease) in cash and cash equivalents	199	(24)
Cash and cash equivalents, beginning of period	305	54
Cash and cash equivalents, end of period	504	30
Cash income taxes paid	2	8
Cash interest paid	22	21

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 Committee on behalf of the Board of Directors on May 5, 2017.

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 for information regarding judgments and estimates.

2. Significant Accounting Policies

A. Current Accounting Changes

I. Change in Estimates – Useful Lives

As a result of the Alberta Off-Coal Arrangement described in Note 4(A) of the Corporation's most recent annual consolidated financial statements, the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the three months ended March 31, 2017 increased in total by approximately $14 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $58 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 International Accounting Standards Board ("IASB") but are not yet effective, and have not been applied by the Corporation, include International Financial Reporting Standards ("IFRS") 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers,* and IFRS 16 *Leases*. Refer to *Note 3* of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16.

The Corporation has made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on its financial statements and disclosures. The Corporation's current estimate of the time and effort necessary to complete the implementation plan for IFRS 9 extends into mid-to-late 2017.

The Corporation has created an implementation plan and is currently in the process of reviewing its various revenue streams and underlying contracts with customers to determine the impact that the adoption of IFRS 15 will have on its financial statements. The Corporation's current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid-to-late 2017. The Corporation anticipates finalizing a decision with respect to the transition method by mid-2017.

The Corporation is in the process of completing its initial scoping assessment for IFRS 16 and expects to have an implementation plan in place by mid-2017. We anticipate that most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on the Corporation's financial statements and disclosures.

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. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced that it had signed a Non-Utility Generator ("NUG") Contract with the Ontario's Independent Electricity System Operator for its Mississauga cogeneration facility. The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018.

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in northeastern Ontario.

As outlined in Note 8A of the 2016 Consolidated Financial Statements, the Corporation recognized a pre-tax gain of approximately $191 million in 2016 and also recognized $46 million in accelerated depreciation. As a result, over the duration of the contract, the Corporation does not expect to recognize any further net earnings impacts. However, the Corporation's cash flow from operating activities will include the contractual monthly payments received under the NUG Contract.

B. Wintering Hills Sale

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale closed March 1, 2017.

C. Preferred Share Exchange

On Feb. 10, 2017, the Corporation announced that it would not proceed with the transaction previously announced on Dec. 19, 2016, pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares in the capital of the Corporation.

4. Net Other Operating Income

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an Off-Coal Agreement ("OCA") with the Government of Alberta on transition payments 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 will receive annual cash payments on or before July 31 of approximately $39.9 million ($37.4 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. Accordingly, during the three months ended March 31, 2017, approximately $10 million was recognized in Net Other Operating Income in the Condensed Consolidated Statement of Earnings. 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 the combustion of coal.

5. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended March 31	
	2017	2016
Interest on debt	56	57
Interest income	(1)	(1)
Capitalized interest	(3)	(3)
Interest on finance lease obligations	1	1
Other[1]	4	4
Accretion of provisions	5	6
Net interest expense	62	64

(1) 2016 includes interest accrued related to the Keephills 1 outage.

6. Income Taxes

The components of income tax expense are as follows:

	3 months ended March 31	
	2017	2016
Current income tax expense	6	5
Deferred income tax recovery related to the origination and reversal of temporary differences	(17)	(1)
Deferred income tax expense resulting from changes in tax rates or laws	-	1
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets[1]	(6)	(23)
Income tax recovery	(17)	(18)

(1) During the three months ended March 31, 2017, the Corporation reversed a previous writedown of deferred income tax assets of $6 million. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. Recognized other comprehensive income during the 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.

	3 months ended March 31	
	2017	2016
Current income tax expense	6	5
Deferred income tax recovery	(23)	(23)
Income tax recovery	(17)	(18)

7. Non-Controlling Interests

The Corporation's subsidiaries with significant non-controlling interests are TransAlta Renewables Inc. ("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 the 150 MW Kent Hills wind farm located in New Brunswick.

The Corporation's share of ownership and equity participation in TransAlta Renewables changed during the three months ended March 31, 2017 as follows:

Period	Ownership and voting rights percentage	Equity participation percentage(1)
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 and thereafter	64.0	59.8

(1) As the Class B shares issued to the Corporation in the sale of the Australian assets were determined to constitute financial liabilities of TransAlta Renewables and do not participate in earnings until commissioning of the South Hedland facility, they are excluded from the allocation of equity and earnings.

Amounts attributable to non-controlling interests are as follows:

	3 months ended March 31	
	2017	2016
Net earnings (loss)		
TransAlta Cogeneration L.P.	20	11
TransAlta Renewables	12	(14)
	32	(3)
Total comprehensive income (loss)		
TransAlta Cogeneration L.P.	19	14
TransAlta Renewables	18	(14)
	37	-
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	26	19
TransAlta Renewables	21	20
	47	39

As at	March 31, 2017	Dec. 31, 2016
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	295	301
TransAlta Renewables	847	851
	1,142	1,152
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	49.99	49.99
TransAlta Renewables	40.2	40.2

8. 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 unadjusted quoted prices 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 observable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses.

Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at	March 31, 2017		Dec. 31, 2016	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	927	+157 -157	907	+75 -69
Long-term power sale - Alberta	1	+3 -3	(3)	+5 -5
Unit contingent power purchases	21	+3 -4	13	+2 -4
Structured products - Eastern U.S.	29	+8 -8	24	+8 -8
Others	3	+4 -4	6	+3 -3

i. Long-Term Power Sale - U.S.

The Corporation has a long-term fixed price power sale contract in the U.S. 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 March 2019, 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 averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per Megawatt hour ("MWh") used in determining the Level III base fair value at March 31, 2017 are US$26 - US$36 (Dec. 31, 2016 - US$27 - US$36). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2016 – US$5) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. The change in the US dollar against the Canadian dollar did not have a material impact on the base fair value this period.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as held for trading.

For periods beyond 2022, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high, and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at March 31, 2017 are $67 - $82 (Dec. 31, 2016 - $68 - $93). The sensitivity analysis for both periods has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. 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 held for trading.

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

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at March 31, 2017 are nil (Dec. 31, 2016 – nil) and 2.15 per cent to 3.54 per cent (Dec. 31, 2016 – 2.15 per cent to 3.62 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 0.73 per cent (Dec. 31, 2016 – 0.75 per cent) and a change in volumetric discount rates of approximately 8.6 per cent (Dec. 31, 2016 – 15.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern U.S.

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

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at March 31, 2017, are 68 per cent to 120 per cent and 68 per cent to 88 per cent (Dec. 31, 2016 – 66 per cent to 128 per cent and 65 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 5 per cent (Dec. 31, 2016 – 5 per cent) and a change in non-standard shape factors of approximately 7 per cent (Dec. 31, 2016 – 9 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at March 31, 2017 are 20 per cent to 51 per cent and 70 per cent (Dec. 31, 2016 – 20 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 and correlation of approximately 10 per cent (Dec. 31, 2016 – 10 per cent), respectively.

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 Levels as at March 31, 2017 are as follows: Level I - $3 million net liability (Dec. 31, 2016 – nil), Level II - $9 million net liability (Dec. 31, 2016 - $14 million net liability), Level III - $784 million net asset (Dec. 31, 2016 – $758 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2017, are primarily attributable to the changes in value of the long-term power sale contract (Level III hedge) as discussed in the preceding section (B)(I)(c)(i) of this note.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities during the three months ended March 31, 2017 and 2016, respectively:

	3 months ended March 31, 2017			3 months ended March 31, 2016		
	Hedge	Non-Hedge	Total	Hedge	Non-Hedge	Total
Opening balance	726	32	758	640	(98)	542
Changes attributable to:						
Market price changes on existing contracts	40	8	48	66	(22)	44
Market price changes on new contracts	-	8	8	-	4	4
Contracts settled	(15)	(3)	(18)	(13)	65	52
Change in foreign exchange rates	(12)	-	(12)	(68)	2	(66)
Net risk management assets at end of period	739	45	784	625	(49)	576
Additional Level III information:						
Gains (losses) recognized in OCI	28	-	28	(2)	-	(2)
Total gains (losses) included in earnings before income taxes	15	16	31	13	(16)	(3)
Unrealized gains included in earnings before income taxes relating to net assets held at March 31, 2017	-	13	13	-	49	49

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 $151 million as at March 31, 2017 (Dec. 31, 2016 - $176 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended March 31, 2017 are primarily attributable to market price changes on existing contracts.

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow and fair value hedges on US$690 million and US$50 million of debt, respectively. As at March 31, 2017, cumulative gains on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. As at March 31, 2017, cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt's maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

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 value
	Level I	Level II	Level III	Total	
Long-term debt - March 31, 2017	**-**	**4,320**	**-**	**4,320**	**4,236**
Long-term debt(1) - Dec. 31, 2016	-	4,271	-	4,271	4,221

(1) Includes current portion and excludes $67 million of debt measured and carried at fair value.

The fair values of the Corporation's debentures and senior notes are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability.

C. Inception Gains and Losses

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

	3 months ended March 31	
	2017	2016
Unamortized net gain at beginning of period	**148**	202
New inception gains	**5**	2
Change in foreign exchange rates	**(2)**	(12)
Amortization recorded in net earnings during the period	**(8)**	(18)
Unamortized net gain at end of period	**143**	174

9. Risk Management Activities

A. Net Risk Management Assets and Liabilities

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

As at March 31, 2017	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	121	-	(12)	109
Long-term	671	-	(8)	663
Net commodity risk management assets (liabilities)	792	-	(20)	772
Other				
Current	-	-	101	101
Long-term	-	-	50	50
Net other risk management assets	-	-	151	151
Total net risk management assets	792	-	131	923

As at Dec. 31, 2016	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	86	-	(16)	70
Long-term	683	-	(9)	674
Net commodity risk management assets (liabilities)	769	-	(25)	744
Other				
Current	105	-	8	113
Long-term	59	3	1	63
Net other risk management assets	164	3	9	176
Total net risk management assets (liabilities)	933	3	(16)	920

B. 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.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at March 31, 2017, associated with the Corporation's proprietary trading activities was $1 million (Dec. 31, 2016 - $2 million).

ii. Commodity Price Risk - Generation

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

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes.

VaR at March 31, 2017, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $17 million (Dec. 31, 2016 - $19 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at March 31, 2017, associated with these transactions was $3 million (Dec. 31, 2016 - $7 million).

b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the U.S. dollar, and the Australian dollar ("AUD"), as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers. Further discussion on Currency Rate Risk can be found in Note 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 March 31, 2017:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables(1)	91	9	100	657
Long-term finance lease receivables(2)	35	65	100	697
Risk management assets(1)	100	-	100	1,058
Total				2,412

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) The Corporation has one non-investment grade customer whose outstanding balance accounted for $437 million (Dec. 31, 2016 - $445 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid-to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at March 31, 2017, was $19 million (Dec. 31, 2016 - $14 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. As at March 31, 2017, TransAlta maintains investment grade ratings from three credit rating agencies (See Note 16). TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies. See Note 16 - Subsequent Events for further details on the downgrade of debt and Preferred Shares ratings.

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

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Accounts payable and accrued liabilities	457	-	-	-	-	-	457
Long-term debt(1)	604	947	461	460	63	1,727	4,262
Commodity risk management assets	(84)	(86)	(85)	(77)	(99)	(341)	(772)
Other risk management (assets) liabilities	(101)	(56)	4	2	-	-	(151)
Finance lease obligations	12	13	10	8	6	19	68
Interest on long-term debt and finance lease obligations(2)	167	173	143	116	95	754	1,448
Dividends payable	33	-	-	-	-	-	33
Total	1,088	991	533	509	65	2,159	5,345

(1) Excludes impact of hedge accounting.

(2) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

C. Collateral and Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at March 31, 2017, the Corporation had posted collateral of $109 million (Dec. 31, 2016 - $116 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 $47 million (Dec. 31, 2016 - $49 million) of collateral to its counterparties.

10. 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 Dec. 31, 2016	95	2,664	498	2,290	606	407	264	6,824
Additions	-	-	-	-	-	60	-	60
Disposals	-	-	-	-	-	-	(1)	(1)
Depreciation	-	(81)	(14)	(31)	(17)	-	(5)	(148)
Revisions and additions to decommissioning and restoration costs	-	65	3	3	(8)	-	-	63
Retirement of assets	-	(1)	-	(2)	-	-	-	(3)
Change in foreign exchange rates	-	(5)	9	(3)	(1)	13	3	16
Transfers	1	4	5	6	2	(20)	2	-
As at March 31, 2017	96	2,646	501	2,263	582	460	263	6,811

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

11. 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	March 31, 2017			Dec. 31, 2016		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Debentures	1,045	1,051	6.0%	1,045	1,051	6.0%
Senior notes[2]	2,116	2,125	5.0%	2,151	2,158	5.0%
Non-recourse[3]	1,023	1,034	4.5%	1,038	1,048	4.5%
Other[4]	52	52	9.2%	54	54	9.2%
	4,236	4,262		4,288	4,311	
Finance lease obligations	68			73		
	4,304			4,361		
Less: current portion of long-term debt	(615)			(623)		
Less: current portion of finance lease obligations	(15)			(16)		
Total current long-term debt and finance lease obligations	(630)			(639)		
Total credit facilities, long-term debt, and finance lease obligations	3,674			3,722		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) U.S. face value at March 31, 2017 - US$1.6 billion (Dec. 31, 2016 - US$1.6 billion).
(3) Includes US$50 million at March 31, 2017 (Dec. 31, 2016 - US$53 million).
(4) Includes US$28 million at March 31, 2017 (Dec. 31, 2016 - US$29 million) of tax equity financing.

Of the $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities, $1.4 billion (Dec. 31, 2016 - $1.4 billion) is not drawn. At March 31, 2017, the $0.6 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, TransAlta also has $504 million of available cash and cash equivalents.

The total outstanding letters of credit as at March 31, 2017 was $556 million (Dec. 31, 2016 - $566 million) with no (Dec. 31, 2016 - nil) amounts exercised by third parties under these arrangements.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at March 31, 2017, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of $192 million (Dec. 31, 2016 - $193 million) issued by the Corporation's subsidiary, Canadian Hydro Developers, Inc. ("CHD"), include restrictive covenants requiring the cash proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures.

Other non-recourse debt of $830 million in total (Dec. 31, 2016 - $845 million) is subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by certain 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 restrictions include the ability to meet a debt service coverage ratio prior to distribution, which was not met by one of the Corporation's subsidiaries, New Richmond Wind L.P. in the first quarter of 2017, mainly due to annualization of its results for purposes of the test. The funds in this entity will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2017. At March 31, 2017, $44 million (Dec. 31, 2016 - $24 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts are established and funded through cash held on deposit and/or by providing letters of credit. As at March 31, 2017, $16 million of cash was on deposit for certain reserves and was not available for general use.

C. Security

Non-recourse debts of $638 million (Dec. 31, 2016 - $644 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 renewable generation facilities with total carrying amounts of $944 million at March 31, 2017 (Dec. 31, 2016 - $956 million). At March 31, 2017, a non-recourse bond of approximately $192 million (Dec. 31, 2016 - $201 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

12. Common Shares

A. Issued and Outstanding

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

	3 months ended March 31			
	2017		2016	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**287.9**	**3,095**	284.0	3,077
Issued under the dividend reinvestment and optional common share purchase plan	**-**	**-**	3.9	18
	287.9	**3,095**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**-**	**(1)**	-	(2)
Issued and outstanding, end of period	**287.9**	**3,094**	287.9	3,093

B. Dividends

On April 19, 2017, the Corporation declared a dividend of $0.04 per common share, payable on July 1, 2017.

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

C. Stock Options

In March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance.

In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance.

13. 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 fixed preferred shares.

As at March 31, 2017 and Dec. 31, 2016, the Corporation had 10.2 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares issued and 1.8 million Series B Cumulative Redeemable Floating Rate First Preferred Shares issued and outstanding.

B. Dividends

The following table summarizes the preferred share dividends declared within the three months ended March 31:

Series	Quarterly amounts per share	2017(1) Total	2016 Total
A	0.16931(2)	-	4
B	-(3)	-	-
C	0.2875	-	3
E	0.3125	-	3
G	0.33125	-	2
Total for the period		-	12

(1) No dividends were declared in the first quarter, as on Dec. 19, 2016, the quarterly dividend related to the period covering the first quarter of 2017 was declared.

(2) Dividends on Class A shares for the first quarter of 2016 were $0.2875 per share.

(3) Series B shares pay quarterly dividends at a floating rate based on the 90 day Government of Canada Treasury Bill rate, plus 2.03%. The Series B shares were issued on March 17, 2016.

On April 19, 2017, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.15645 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on June 30, 2017.

14. Commitments and Contingencies

A. Commitments

During the first quarter of 2017, the Corporation extended and revised its existing agreement with Alstom to provide major maintenance for the Corporation's Canadian Coal facilities. The agreement relates to major maintenance projects over the 2017 through 2020 years at the Corporation's Keephills plants and on some Sundance plants. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

B. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation is participating in a line loss rule proceeding (the "LLRP") that is currently before the Alberta Utilities Commission ("AUC"). The AUC determined that it had the ability to retroactively adjust line loss rates going back to 2006 and directed the Alberta Electric System Operator (the "AESO") to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. The Corporation may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP, however, currently remains uncertain and the total potential exposure faced by the Corporation, if any, cannot be calculated with certainty until retroactive calculations using a AUC-approved methodology are made available, and until the AUC determines what methodology will be used for retroactive calculations. The AESO expects retroactive calculations for each year using a AUC-approved methodology to begin to be available in the second quarter of 2017, at the earliest.

As a result, no provision has been recorded at this time. Further, certain PPAs for the Corporation's facilities provide for the pass through of these types of transmission charges to the Corporation's buyers.

15. Segment Disclosures

A. Reported Segment Earnings (Loss)

I. Earnings Information

3 months ended March 31, 2017	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	250	88	102	26	87	24	1	-	578
Fuel and purchased power, and other	139	64	39	2	5	1	-	-	250
Gross margin	111	24	63	24	82	23	1	-	328
Operations, maintenance, and administration	44	13	12	7	12	8	5	24	125
Depreciation and amortization	70	15	9	7	27	8	-	7	143
Taxes, other than income taxes	3	1	1	-	2	1	-	-	8
Other net operating income	(10)	-	-	-	-	-	-	-	(10)
Operating income (loss)	4	(5)	41	10	41	6	(4)	(31)	62
Finance lease income	-	-	3	13	-	-	-	-	16
Net interest expense									(62)
Foreign exchange loss									(1)
Earnings before income taxes									15

3 months ended March 31, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	234	56	105	29	84	28	32	-	568
Fuel and purchased power, and other	98	52	42	5	9	2	-	-	208
Gross margin	136	4	63	24	75	26	32	-	360
Operations, maintenance, and administration	45	12	14	6	12	7	9	18	123
Depreciation and amortization	61	(3)	14	5	30	7	1	7	122
Taxes, other than income taxes	3	1	1	-	2	1	-	-	8
Operating income (loss)	27	(6)	34	13	31	11	22	(25)	107
Finance lease income	-	-	3	13	-	-	-	-	16
Net interest expense									(64)
Foreign exchange loss									(6)
Earnings before income taxes									53

Included in revenues of the Wind and Solar Segment for the three months ended March 31, 2017 are $5 million (2016 - $7 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

During the three months ended March 31, 2017, coal inventory at the Corporation's Centralia plant was written down by nil (2016 - $6 million) to its net realizable value. The writedown was included in fuel and purchased power of the U.S. Coal Segment.

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

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

	3 months ended March 31	
	2017	2016
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	143	122
Depreciation included in fuel and purchased power	17	14
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	160	136

16. Subsequent Events

A. Change in Credit Rating

The Corporation maintains investment grade ratings from three credit rating agencies.

On March 15, 2017, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable.

On April 3, 2017, DBRS Limited changed the Corporation's Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating BBB to BBB (low).

On April 11, 2017, Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- but changed the outlook from stable to negative.

B. Transition to Clean Power in Alberta

On April 19, 2017, the Corporation announced the Corporation's strategy to accelerate the Corporation's transition to gas and renewables generation. The strategy includes the following steps:

- retirement of Sundance Unit 1 effective Jan. 1, 2018;
- mothballing of Sundance Unit 2 effective Jan. 1, 2018, for a period of 2 years; and
- conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2023 timeframe, thereby extending the useful lives of these units until the mid-2030's.

Sundance Units 1 and 2

Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, we intend to apply to the federal Minister of Environment to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide the Corporation with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively comprise 560 MW of the 2,141 MW at the Sundance power plants, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expires on Dec. 31, 2017. The Corporation will assess the impact of the retirement and mothballing of Sundance Units 1 and 2 in the second quarter of 2017.

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 three months ended March 31, 2017:

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

1.52 times [(1)]

(1) Last 12 months. Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Supplemental Information

		March 31, 2017	Dec. 31, 2016
Closing market price (TSX) ($)		7.82	7.43
Price range for the last 12 months (TSX) ($)	High	8.07	7.54
	Low	5.17	3.76
Adjusted net debt to invested capital[1] (%)		49.5	51
Adjusted net debt to invested capital excluding non-recourse debt[1] (%)		42.4	44.2
Adjusted net debt to comparable EBITDA[1, 2] (times)		3.6	3.8
Return on equity attributable to common shareholders[2] (%)		2.5	5.4
Return on capital employed[2] (%)		4.6	5.3
Earnings coverage[2] (times)		1.4	1.7
Dividend payout ratio based on FFO[1, 2, 3] (%)		6.1	7.8
Dividend coverage[2,3] (times)		17.1	11.5
Dividend yield[2,3]		1.5	4.0
Adjusted FFO to adjusted net debt[2] (%)		18.2	17.0
FFO before interest to adjusted interest coverage[2] (times)		3.8	3.8

Ratio Formulas

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

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 - cash and cash equivalents + 50 per cent issued preferred shares / comparable EBITDA

Return on equity attributable to common shareholders = net earnings attributable to common shareholders / equity attributable to common shareholders excluding AOCI

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

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

(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 Additional IFRS and Non-IFRS Measures section of this MD&A.

(2) Last 12 months.

(3) On Jan. 14, 2016, we revised our dividend to $0.16 per common share on an annualized basis from $0.72 previously. The effect of the change is not reflected in these historical ratios.

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

Dividend coverage ratio = cash flow from operating activities / cash dividends paid on common shares

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

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

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

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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