



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, 2016 and 2015, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2015 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, 2016. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated May 2, 2016. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov, and on our website at www.transalta.com. Information on or connected to our website is not incorporated by reference herein.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income in our Condensed Consolidated Statements of Earnings (Loss) for the three months ended March 31, 2016, and 2015. 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. See the Comparable Funds from Operations and Comparable Free Cash Flow, Discussion of Segmented Comparable Results, and Earnings and Other Measures on a Comparable Basis 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, including the 2016 Financial Outlook section of this MD&A, 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 their attendant costs; 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 impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2016 comparable earnings before interest, taxes, depreciation, and amortization (“EBITDA”), comparable funds from operations (“FFO”), comparable free cash flow (“FCF”), and expected sustaining capital expenditures for 2016); expectations in respect of financial ratios and targets (including comparable FFO before interest to adjusted interest coverage, adjusted comparable 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 debt reductions that are expected to occur in 2016 and beyond; expected governmental regulatory regimes and legislation (including the Government of Alberta’s Climate Leadership Plan and the Government of Ontario’s greenhouse gas cap and trade program) and their expected impact on TransAlta and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the outcome of negotiations with the Government of Alberta in relation to coal-fired generation transition under the Climate Leadership Plan; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expected financing of our capital expenditures; 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; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; our expectations on dividend payments; expectations for the ability to access capital markets at 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 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 regarding our continued ownership of TransAlta Renewables Inc. (“TransAlta Renewables”) common shares; expectations on the impact of the potential transfer of the Alberta Power Purchase Arrangements (“PPA”) to the Balancing Pool; and expectations of the financial impact of our agreement with the Government of Alberta in respect of flood and drought mitigation.

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, or wind required to operate our facilities; natural or man-made disasters; the threat of terrorism and cyberattacks; 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; 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 of the South Hedland power project; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our 2015 Annual MD&A and under the heading "Risk Factors" in our 2016 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise, except as required by applicable laws. In light of these risks, uncertainties, and assumptions, the forward-looking events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

Highlights

Consolidated Financial Highlights

3 months ended March 31	2016	2015
Revenues	568	593
Comparable EBITDA ⁽¹⁾	279	275
Net earnings (loss) attributable to common shareholders (<i>Restated</i> ⁽²⁾)	62	(40)
Comparable net earnings attributable to common shareholders ⁽¹⁾	14	26
Comparable FFO ⁽¹⁾	196	211
Cash flow from operating activities	275	153
Comparable FCF ⁽¹⁾	86	110
Net earnings (loss) per share attributable to common shareholders, basic and diluted (<i>Restated</i> ⁽²⁾)	0.22	(0.14)
Comparable net earnings per share ⁽¹⁾	0.05	0.09
Comparable FFO per share ⁽¹⁾	0.68	0.76
Comparable FCF per share ⁽¹⁾	0.30	0.40
Dividends declared per common share	0.04	0.18

As at	March 31, 2016	Dec. 31, 2015
Total assets	10,554	10,947
Total credit facilities, long-term debt, tax equity, and finance lease obligations ⁽³⁾ , net of cash	4,000	4,441
Total long-term liabilities	5,227	5,704

- Comparable EBITDA for the quarter increased by \$4 million to \$279 million compared to the same period in 2015 with all segments other than U.S. Coal delivering similar or improved results over last year. Low prices in Alberta were largely mitigated through our hedging strategies and cost reduction initiatives. Asset acquisitions in 2015 contributed positively to our results in the first quarter of 2016. The decreased contribution from U.S. Coal is attributable to unfavourable market conditions in the Pacific Northwest.
- Comparable FFO for the quarter decreased by \$15 million to \$196 million compared to the same period in 2015. Last year, FFO was positively impacted by realized currency gains.
- Comparable net earnings attributable to common shareholders for the three months ended March 31, 2016 was \$14 million (\$0.05 net earnings per share), down from comparable net earnings of \$26 million (\$0.09 net earnings per share) during the three months ended March 31, 2015. The decrease was primarily due to higher earnings attributable to non-controlling interests, resulting from higher outstanding shares of TransAlta Renewables owned by the public.
- Reported net earnings attributable to common shareholders was \$62 million (\$0.22 net earnings per share) compared to a net loss of \$40 million (\$0.14 net loss per share) for the same period in 2015. Last year, net earnings were reduced by a \$55 million income tax charge associated with the sale of an economic interest in our Australian business to TransAlta Renewables and a \$31 million (\$20 million after-tax) negative change in the fair value of de-designated and economic hedges at U.S. Coal. Reported earnings in 2016 include \$29 million of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests.
- The decrease in credit facilities, long-term debt, and finance lease obligations is primarily due to the repayment of our credit facilities with cash received from the sale of economic interests in certain Canadian assets completed in January. The strengthening of the Canadian dollar at the end of March also contributed to the reduction in balances from December.

(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 Comparable FFO and Comparable FCF and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) 2015 restated to reflect prior period correction to tax. Refer to the Accounting Changes section of this MD&A.

(3) Includes current portion.

Highlights

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

- On Jan. 6, 2016, TransAlta Renewables acquired from us an economic interest based on the cash flows of the Sarnia cogeneration facility and of two renewable energy facilities for proceeds valued at \$540 million. Cash proceeds of this transaction were \$173 million. We also received 15.6 million common shares of TransAlta Renewables and a \$215 million convertible debenture.
- During the quarter, our 12 million Series A Preferred Shares reached their first reset date. Approximately 10.2 million shares will now pay fixed dividends of nearly \$0.68 per share annually (2.7 per cent) until their next reset date in 2021 (down from \$1.15 per share) and approximately 1.8 million shares were converted into Series B Preferred Shares, which currently pay dividends of approximately \$0.62 per share (down from \$1.15 per share) on an annualized basis (2.5 per cent), adjusted quarterly. Declaration of dividends remains subject to approval by the Board of Directors (the "Board").
- We continued to advance the construction of the South Hedland power project. The bulk of the major equipment has arrived at site. We continue to expect the project to be delivered on schedule and on budget in mid-2017.
- On Jan. 14, 2016, we revised our dividend to \$0.16 per common share on an annualized basis from \$0.72 previously, and suspended our dividend reinvestment plan. As a result, our annual dividend going forward will be approximately \$46 million, down from \$205 million, increasing our financial flexibility.

In March 2016, the buyers under the legislated Sundance and Sheerness PPAs announced their intention to transfer their respective obligations under the PPAs to the Balancing Pool as a result of a Change in Law. The Balancing Pool is presently investigating whether these transfers are permitted by the terms of the PPAs in the current circumstances and, if so, when the transfers would become effective. The outcome remains uncertain. If the Balancing Pool confirms the transfers, it will assume the role of the buyers and carry out the responsibilities of the buyers under the PPAs, including dispatching the generating units and making the capacity and energy payments to TransAlta until the end of the PPA terms. Pursuant to the *Electric Utilities Act* (Alberta), it could also choose to terminate the PPAs after following the requirements of legislation, which would include paying TransAlta an amount equal to the applicable closing net book value of the generating units. TransAlta does not presently expect the transfer of the PPAs to the Balancing Pool to have a material impact on our business.

On March 16, 2016, the Alberta Government appointed Terry Boston, the former CEO of North America's largest power system, as Coal Phase-out Facilitator to lead discussions on coal transition as part of the Climate Leadership Plan. Discussions with the coal-fired generators, including TransAlta, are now in progress.

On April 27, 2016, we announced that we entered into a five-year agreement with the Government of Alberta to manage water for flood mitigation and drought mitigation through our Ghost reservoir and our Kananaskis hydro system. The Alberta government will provide us with \$5.5 million in compensation annually to offset the impacts modified operations will have on our ability to generate power at these facilities.

Segmented Operational Results

Comparable EBITDA and operational performance for the business is as follows:

3 months ended March 31	2016	2015
Availability (%)	92.3	89.8
Adjusted availability (%) ⁽¹⁾	92.3	91.3
Production (GWh) ⁽¹⁾	8,867	9,900
Comparable EBITDA		
Canadian Coal	103	95
U.S. Coal ⁽²⁾	(4)	22
Canadian Gas ⁽²⁾	65	57
Australian Gas ⁽²⁾	31	27
Wind and Solar	61	55
Hydro	18	14
Energy Marketing	23	23
Corporate	(18)	(18)
Total comparable EBITDA	279	275

- Canadian Coal: Comparable EBITDA increased by \$8 million to \$103 million in the first quarter, compared to the same period in 2015, as cost reductions and effective hedging strategies have offset lower prices on uncontracted generation. Availability was also higher than last year.
- U.S. Coal: Comparable EBITDA was a \$4 million loss for the quarter, compared to earnings of \$22 million for the same period in 2015 due to lower realized prices and mark-to-market losses on financial contracts put in place to hedge our future generation. The first quarter of 2015 benefited from higher price hedges entered into during a higher price environment in 2014.
- Canadian Gas: Comparable EBITDA increased by \$8 million during the first quarter to \$65 million compared to the same period in 2015. Last year's results included \$4 million unrealized mark-to-market on our gas position, compared to a gain of \$3 million this quarter.
- Australian Gas: Comparable EBITDA increased by \$4 million during the first quarter to \$31 million, compared to the same period in 2015, largely as a result of additional revenues from the natural gas pipeline that was commissioned in late March 2015.
- Wind and Solar: Comparable EBITDA is up \$6 million during the quarter, compared to the same period in 2015, due to the contribution of projects with a combined capacity of 136 MW acquired during the second half of 2015. Higher generation from our portfolio caused by stronger wind resources compared to last year offset the impact of lower prices in Alberta.
- Hydro: Comparable EBITDA increased by \$4 million to \$18 million, primarily due to an adjustment of prior years' production volumes, and cost reduction initiatives.
- Energy Marketing: Comparable EBITDA remained consistent with 2015.
- Corporate: Our Corporate overhead costs during the quarter have remained similar to 2015, as our cost reductions were offset by reduced allocations to our business segments.

(1) Adjusted for economic dispatching at U.S. Coal.

(2) See the Accounting Changes section of this MD&A for information on changes in the presentation of the Gas reportable segment.

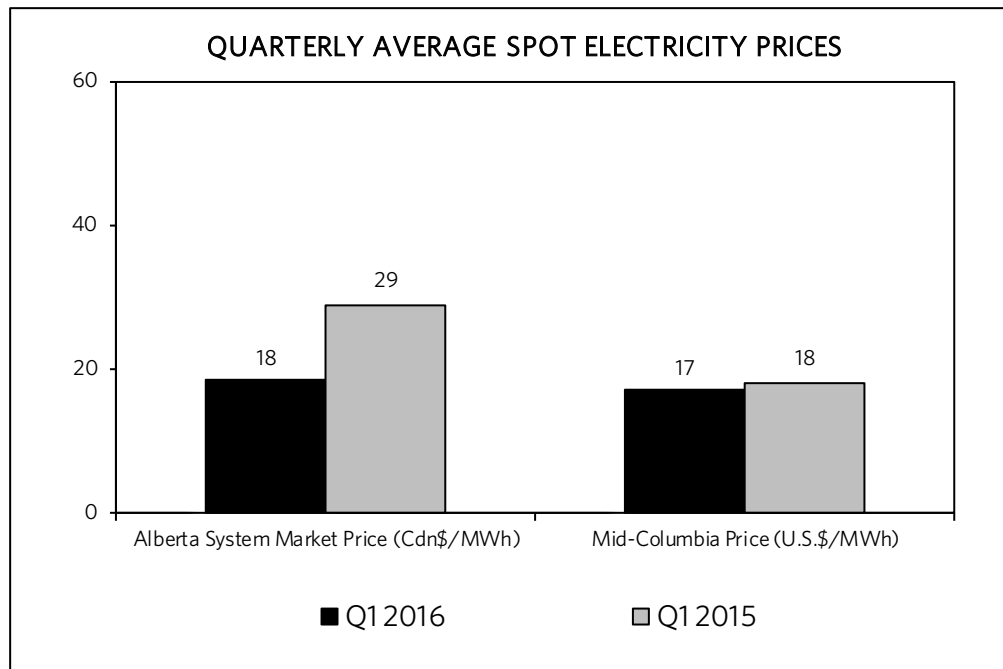
Availability and Production

Availability for the three months ended March 31, 2016 improved over same period in 2015 as a result of lower unplanned outages at Canadian Coal.

Production for the three months ended March 31, 2016 decreased by 1,033 gigawatt hours (“GWh”) compared to the same period in 2015, primarily due to the restructuring of our contractual arrangement at Poplar Creek in the third quarter of 2015, and low prices in Ontario and the Pacific Northwest.

Electricity Prices

The average spot electricity prices for the three months ended March 31, 2016 decreased compared to 2015 in both Alberta and the Pacific Northwest markets. Lower natural gas prices and seasonally low demand have muted volatility and depressed prices. We do not expect prices to increase significantly in Alberta during the balance of 2016.



Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO and comparable FCF provide a proxy for the amount of cash generated from operating activities before changes in working capital, and provide the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FFO per share and comparable FCF per share are calculated using the weighted average number of common shares outstanding during the period.

3 months ended March 31	2016	2015
Cash flow from operating activities	275	153
Change in non-cash operating working capital balances	(94)	49
Cash flow from operations before changes in working capital	181	202
Adjustments		
Decrease in finance lease receivable	14	1
Payment of restructuring costs	-	7
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	-	1
Other	1	-
Comparable FFO	196	211
Deduct:		
Sustaining capital	(59)	(70)
Dividends paid on preferred shares	(12)	(12)
Distributions paid to subsidiaries' non-controlling interests	(39)	(19)
Comparable FCF	86	110
Weighted average number of common shares outstanding in the period	288	277
Comparable FFO per share	0.68	0.76
Comparable FCF per share	0.30	0.40

Comparable FCF for the three months ended March 31, 2016 decreased by \$24 million as a result of lower comparable FFO and increased non-controlling interest dividend payments associated with the additional shares issued and sold to non-controlling interests in TransAlta Renewables in 2015 and 2016. Lower than last year sustaining capital partly offset the shortfall in comparable FCF.

A reconciliation of comparable EBITDA to comparable FFO is as follows:

3 months ended March 31	2016	2015
Comparable EBITDA	279	275
Interest expense	(58)	(55)
Unrealized (gains) losses from risk management activities	(7)	5
Current income tax expense	(5)	(6)
Provisions	1	(9)
Decommissioning and restoration costs settled	(3)	(5)
Realized foreign exchange gain (loss)	(1)	8
Other non-cash items	(10)	(2)
Comparable FFO	196	211

For the first quarter 2016, comparable FFO decreased by \$15 million to \$196 million compared to the first quarter 2015, mainly due to higher unrealized gains included in EBITDA, lower realized foreign exchange gains, and an increase in long-term receivables, partially offset by a reduction to provisions.

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.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

As at	March 31, 2016	Dec. 31, 2015
Comparable FFO ⁽¹⁾	725	740
Add: Interest on debt net of capitalized interest ⁽¹⁾	226	223
Comparable FFO before interest⁽¹⁾	951	963
Interest on debt ⁽¹⁾	235	232
Add: 50 per cent of dividends paid on preferred shares ⁽¹⁾	23	23
Adjusted interest⁽¹⁾	258	255
Comparable FFO before interest to adjusted interest coverage (times)	3.7	3.8

Our target for comparable FFO before interest to adjusted interest coverage is four to five times. The ratio deteriorated slightly compared to Dec. 31, 2015 primarily due to lower FFO over the last 12 months.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

As at	March 31, 2016	Dec. 31, 2015
Comparable FFO ⁽¹⁾	725	740
Less: 50 per cent of dividends paid on preferred shares ⁽¹⁾	(23)	(23)
Adjusted comparable FFO⁽¹⁾	702	717
Period-end long-term debt ⁽²⁾	4,030	4,495
Add: 50 per cent of issued preferred shares	471	471
Less: Cash and cash equivalents	(30)	(54)
Fair value asset of hedging instruments on debt ⁽³⁾	(125)	(190)
Adjusted net debt	4,346	4,722
Adjusted comparable FFO to adjusted net debt (%)	16.2	15.2

Our target for adjusted comparable FFO to adjusted net debt is 20 to 25 per cent. The improvement in the ratio during the first quarter is primarily due to our repayment of amounts borrowed under the credit facility following receipt of proceeds from the public offering of additional common shares of TransAlta Renewables and reduction of debt due to the strengthening of the Canadian dollar in March.

(1) Last 12 months. Our target range for comparable FFO in 2016 is \$755 million to \$835 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, 2016 and Dec. 31, 2015.

Adjusted Net Debt to Comparable EBITDA

As at	March 31, 2016	Dec. 31, 2015
Period-end long-term debt ⁽¹⁾	4,030	4,495
Less: Cash and cash equivalents	(30)	(54)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt ⁽²⁾	(125)	(190)
Adjusted net debt	4,346	4,722
Comparable EBITDA⁽³⁾	949	945
Adjusted net debt to comparable EBITDA (times)	4.6	5.0

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. During the first quarter, our ratio improved compared to Dec. 31, 2015, mainly as a result of a lower debt balance.

Significant and Subsequent Events

Sundance and Sheerness PPA Terminations

In March 2016, the buyers under the legislated Sundance and Sheerness PPAs announced their intention to transfer their respective obligations under the PPAs to the Balancing Pool as a result of a Change in Law. The Balancing Pool is presently investigating whether these transfers are permitted by the terms of the PPAs in the current circumstances and, if so, when the transfers would become effective. The outcome remains uncertain. If the Balancing Pool confirms the transfers, it will assume the role of the buyers and carry out the responsibilities of the buyers under the PPAs, including dispatching the generating units and making the capacity and energy payments to TransAlta until the end of the PPA terms. Pursuant to the *Electric Utilities Act* (Alberta), it could also choose to terminate the PPAs after following the requirements of legislation, which would include paying TransAlta an amount equal to the applicable closing net book value of the generating units. TransAlta does not presently expect the transfer of the PPAs to the Balancing Pool to have a material impact on our business.

Credit Ratings Outlook

As at March 31, 2016, we maintain investment grade ratings from three credit rating agencies, but during the first quarter, DBRS and Fitch changed their outlooks from stable to negative. Their negative outlooks are a reflection of low energy prices and concerns over coal generation transition in Alberta. We remain focused on strengthening our financial position by de-leveraging our capital structure and securing a fair agreement with the Government of Alberta to assist them in their goal to transition the generation in the province to gas and renewables.

Flood and Drought Mitigation Agreement

On April 27, 2016, we announced that we entered into a five-year agreement with the Government of Alberta to manage water on the Bow River at our Ghost reservoir facility to aid in potential flood mitigation efforts, as well as our Kananaskis Lakes system (which includes Interlakes, Pocaterra and Barrier), for drought mitigation efforts. As far as is possible, this agreement has been structured to be break-even. TransAlta expects to cover lost revenue if and when water levels must be lowered and power cannot be generated for customers, but does not expect to make a profit. The Alberta government will provide us with \$5.5 million in compensation annually to offset the impacts modified operations will have on our ability to generate power at these facilities.

(1) Includes finance lease obligations and tax equity financing.

(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at March 31, 2016 and Dec. 31, 2015.

(3) Last 12 months. Our target range for comparable EBITDA in 2016 is \$990 million to \$1,100 million.

Conversion of Series A Preferred Shares to Series B Preferred Shares

On March 17, 2016, 1,824,620 of our 12 million Series A Cumulative Redeemable Fixed Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares. For the next five years, the Series A Shares will pay a fixed cumulative preferential cash dividend of \$0.67725 per share annually (down from \$1.15 per share), subject to the Board's dividend declaration. The Series B Shares will pay quarterly floating rate cumulative preferential cash dividends set at the sum of the 90 day Government of Canada Treasury Bill rate plus 2.03 per cent. The annualized quarterly dividend rate for the Series B Shares for the 3-month floating rate period for the second quarter 2016 is \$0.623 per share.

South Hedland

We continued to advance the construction of the South Hedland power project. Major equipment has been arriving on schedule. The bulk of the major equipment has arrived at site. We continue to expect the project to be delivered on schedule and on budget in mid-2017.

Environmental Regulation Updates

Refer to the Environmental and Local Communities Capital section of our 2015 Annual MD&A for further details that supplement the recent developments as discussed below.

Alberta

On Nov. 22, 2015, the Government of Alberta announced through the Climate Leadership Plan its intent, among other things, to phase out emissions from coal-fired generation by 2030, replace two-thirds of the retiring coal-fired generation with renewable generation, and impose a new carbon price of \$30 per tonne of CO₂ emissions based on an industry-wide performance standard. On March 16, 2016, the Government of Alberta announced the appointment of Terry Boston, the former CEO of PJM, North America's largest power system, as the Coal Phase-out Facilitator to work with coal-fired electricity generators, the Alberta Electric System Operator, and the Government of Alberta to develop options to phase out emissions from coal-fired generation by 2030. Mr. Boston is tasked with presenting options to the government that will strive to maintain the reliability of Alberta's electricity grid, maintain stability of prices for consumers, and avoid unnecessarily stranding capital. Discussions with the coal-fired generators, including TransAlta, are now in progress.

In March 2016, Alberta began the development of its renewable energy procurement process designed for the Alberta Electric System Operator to procure a first block of renewable generation projects to be in-service by mid-2019.

Ontario

On Feb. 25, 2016, Ontario released draft regulations for its greenhouse gas cap and trade program. The regulations are to become effective Jan. 1, 2017, and will apply to all fossil fuel 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 power purchase agreements. Further details of the regulations are being developed with public consultation, in which we are participating.

A separate offset regulation will be drafted later in 2016.

U.S. Federal and Pacific Northwest

On Feb. 9, 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending consideration as to whether the regulations are lawful. It is not clear yet how this may affect the future of the Clean Power Plan. As a result of our 2011 agreement for coal transition with the State of Washington, we do not expect the proposed regulations to significantly affect our U.S. operations.

Discussion of Segmented Comparable Results

In January 2016, we began reporting Canadian Gas and Australian Gas as separate business segments. Previously these segments were reported as one business segment, Gas. The segment has now been differentiated geographically to provide additional information to our readers. See the Current Accounting Changes section of this MD&A for additional information.

Comparable figures are not defined under IFRS. Refer to the Earnings and Other Measures on a Comparable Basis section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Canadian Coal

3 months ended March 31	2016	2015
Availability (%)	86.6	84.5
Contract production (GWh)	4,919	4,916
Merchant production (GWh)	909	1,021
Total production (GWh)	5,828	5,937
Gross installed capacity (MW)	3,786	3,771
Revenues	234	246
Fuel and purchased power	83	99
Comparable gross margin	151	147
Operations, maintenance, and administration	45	49
Taxes, other than income taxes	3	3
Comparable EBITDA	103	95
Depreciation and amortization	76	71
Comparable operating income	27	24
Sustaining capital:		
Routine capital	2	8
Mine capital	-	4
Finance leases	3	3
Planned major maintenance	37	30
Total sustaining capital expenditures	42	45

Production for the three months ended March 31, 2016 decreased 109 GWh compared to the same period in 2015, primarily due to higher economic dispatching and paid curtailments as a result of lower prices in Alberta. Availability for the quarter was higher than last year despite execution of significant planned major maintenance activities.

Comparable EBITDA for the three months ended March 31, 2016 was \$103 million compared to \$95 million for the same period in 2015 due to better availability, lower cost of coal, reduction in our gas consumption, and lower operations, maintenance, and administration costs. Our high level of hedges mitigated most of the impact of low power prices on uncontracted generation.

Depreciation and amortization for the three months ended March 31, 2016 increased compared to the same period in 2015 mainly due to higher asset retirements and a higher asset base than 2015.

Sustaining capital expenditures were higher by \$3 million in the first quarter of 2015 as a result of coal hauler rebuilds during the period. In the first quarter of 2016, we completed limited-scope planned major maintenance on two units and started the major overhaul of another unit that was returned to service in April. A partner also completed major maintenance of one unit that we do not operate.

U.S. Coal

3 months ended March 31	2016	2015⁽²⁾
Availability (%)	100.0	91.0
Adjusted availability (%) ⁽¹⁾	100.0	100.0
Contract sales volume (GWh)	915	689
Merchant sales volume (GWh)	402	577
Purchased power (GWh)	(945)	(711)
Total production (GWh)	372	555
Gross installed capacity (MW)	1,340	1,340
Revenues	61	82
Fuel and purchased power	52	47
Comparable gross margin	9	35
Operations, maintenance, and administration	12	12
Taxes, other than income taxes	1	1
Comparable EBITDA	(4)	22
Depreciation and amortization	(3)	15
Comparable operating income (loss)	(1)	7
Sustaining capital:		
Routine capital	1	-
Planned major maintenance	3	3
Total	4	3

For the three months ended March 31, 2016, production decreased 183 GWh compared to the same period in 2015 due mainly to an earlier start to seasonal economic dispatching. Lower prices during the quarter provided us the opportunity to shut down our generation earlier and supply our contractual obligation by buying cheaper power in the market. We are using that time to execute planned major maintenance on both units. We expect the units to be available in June when prices are expected to be higher.

Comparable EBITDA decreased by \$26 million for the three months ended March 31, 2016 compared to the same period in 2015, primarily as a result of much lower realized prices. Results of the first quarter of 2015 benefited from higher priced hedges entered into in 2014.

Depreciation and amortization was in a recovery position in the first quarter of 2016 as a result of higher discount rates being applied to our decommissioning obligation of the Centralia mine. As the mine is in the reclamation stage, the adjustment flows directly to earnings.

(1) Adjusted for economic dispatching.

(2) Restated to include non-operating legacy U.S. Gas costs. Refer to the Accounting Changes section of this MD&A.

Canadian Gas

3 months ended March 31	2016	2015
Availability (%)	99.4	99.8
Contract production (GWh)	743	1,026
Merchant production (GWh)	-	695
Total production (GWh)	743	1,721
Gross installed capacity (MW) ⁽¹⁾	1,057	1,183
Revenues	122	143
Fuel and purchased power	42	67
Comparable gross margin	80	76
Operations, maintenance, and administration	14	18
Taxes, other than income taxes	1	1
Comparable EBITDA	65	57
Depreciation and amortization	28	24
Comparable operating income	37	33
Sustaining capital:		
Routine capital	-	2
Planned major maintenance	2	7
Total	2	9

Production for the three months ended March 31, 2016 decreased 978 GWh compared to the same period in 2015, primarily due to the restructuring of our contract with Suncor at Poplar Creek in the third quarter of 2015 and low prices in Ontario.

Comparable EBITDA for the three months ended March 31, 2016 was \$65 million compared to \$57 million for the same period in 2015, primarily as result of a year over year change in mark-to-market on our gas position. Last year included losses of \$4 million compared to a gain of \$3 million this quarter.

Depreciation and amortization increased \$4 million during the first quarter compared to the same period in 2015 due to the Poplar Creek restructuring that resulted in a higher asset base under a finance lease.

Sustaining capital decreased by \$7 million during the first quarter of 2016 compared to the same period in 2015, primarily as a result of the refurbishment of a spare engine during 2015. Also, the obligation to maintain the Poplar Creek facility has been transferred to our customer as part of our new contract arrangement.

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor. We continue to own a portion of the facility and have included our portion as a part of gross capacity measures. Poplar Creek has been removed from our availability and production metrics, effective Sept. 1, 2015.

Australian Gas

3 months ended March 31	2016	2015
Availability (%)	90.1	88.6
Contract production (GWh)	372	303
Gross installed capacity (MW) ⁽¹⁾	348	348
Revenues	42	38
Fuel and purchased power	5	5
Comparable gross margin	37	33
Operations, maintenance, and administration	6	6
Comparable EBITDA	31	27
Depreciation and amortization	5	4
Comparable operating income	26	23
Sustaining capital:		
Routine capital	1	-

The production increase of 69 GWh during the first quarter of 2016 compared to the same period in 2015 was due to a change in the power import regime at one of our customer's location. Due to the nature of our contract, the change did not have a significant financial impact.

Comparable EBITDA increased by \$4 million during the first quarter of 2016 to \$31 million compared to the same period in 2015, largely as a result of additional revenues from the natural gas pipeline that was commissioned in late March 2015.

(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	2016	2015
Availability (%)	96.8	95.0
Contract production (GWh)	711	637
Merchant production (GWh)	420	340
Total production (GWh)	1,131	977
Gross installed capacity (MW) ⁽¹⁾	1,424	1,289
Revenues	84	73
Fuel and purchased power	9	4
Comparable gross margin	75	69
Operations, maintenance, and administration	12	12
Taxes, other than income taxes	2	2
Comparable EBITDA	61	55
Depreciation and amortization	30	22
Comparable operating income	31	33
Sustaining capital:		
Planned major maintenance	2	2

Production for the first quarter of 2016 increased by 154 GWh compared to the same period in 2015, mainly due to the contribution from assets acquired during the second half of 2015 (97 GWh), and increased generation from our portfolio caused by higher wind volumes across our fleet (57 GWh). Units acquired in 2015 contributed nearly \$6 million of comparable EBITDA during the quarter. Higher generation from our portfolio compared to last year offset the impact of lower prices in Alberta. Outside of Alberta, all of our generation is contracted.

Depreciation and amortization during the first quarter of 2016 increased by \$8 million compared to the same period in 2015, primarily due to the addition of new projects during the second half of 2015 and a \$1 million impact from the retirement of Cowley Ridge, the first commercial wind farm in Canada.

(1) Our 2015 capacity excludes acquisitions completed during the second half of 2015.

Hydro

3 months ended March 31	2016	2015
Contract production (GWh)	417	398
Merchant production (GWh)	4	9
Total production (GWh)	421	407
Gross installed capacity (MW)	926	913
Revenues	28	25
Fuel and purchased power	2	1
Comparable gross margin	26	24
Operations, maintenance, and administration	7	10
Taxes, other than income taxes	1	-
Comparable EBITDA	18	14
Depreciation and amortization	7	6
Comparable operating income	11	8
Sustaining capital:		
Hydro life extension	3	6
Planned major maintenance	2	1
Total	5	7

Production for the first quarter of 2016 increased by 14 GWh compared to the same period in 2015 due to increased water resource over last year.

Comparable EBITDA increased by \$4 million to \$18 million, primarily due to a correction with a buyer of prior years' production volumes, and cost reduction initiatives.

Energy Marketing

3 months ended March 31	2016	2015
Revenues and comparable gross margin	32	31
Operations, maintenance, and administration	9	8
Comparable EBITDA	23	23
Depreciation and amortization	1	-
Comparable operating income	22	23

Comparable EBITDA remained similar to 2015 and in line with our expectations for the first quarter.

Corporate

The expenses incurred by the Corporate Segment are as follows:

3 months ended March 31	2016	2015
Operations, maintenance, and administration and taxes other than income taxes	18	18
Depreciation and amortization	7	6
Comparable operating loss	25	24
Sustaining capital:		
Routine capital	3	4

Our Corporate overhead costs during the quarter have remained comparable to 2015. Benefits of lower costs in the segment from our recent restructuring amounting to approximately \$3 million this period have been primarily passed on to our operating segments.

Other Consolidated Analysis

Income Taxes

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

3 months ended March 31	2016	2015
Earnings before income taxes	53	29
Comparable adjustments:		
Impacts associated with certain de-designated and economic hedges	5	31
Economic hedges of non-controlling interest in intercompany foreign exchange contracts	(2)	-
Restructuring expense	-	7
Flood-related maintenance costs, net of insurance recovery	-	1
Comparable earnings before tax	56	68
Comparable earnings attributable to non-controlling interests before tax	(27)	(16)
Comparable earnings attributable to TransAlta shareholders subject to tax	29	52
Income tax expense (recovery) <i>(Restated⁽¹⁾)</i>	(18)	43
Comparable income tax expense adjustments:		
Income tax expense related to impacts associated with certain de-designated and economic hedges	1	11
Income tax recovery related to restructuring provision	-	2
Income tax recovery related to writedown of deferred income tax assets	23	15
Income tax expense related to investment in subsidiary <i>(Restated⁽¹⁾)</i>	-	(55)
Income tax expense related to changes in corporate income tax rates	(1)	-
Income tax expense related to non-comparable items attributable to economic hedges of non-controlling interest in intercompany foreign exchange contracts	(1)	-
Comparable income tax expense	4	16
Comparable income tax expense attributable to non-controlling interests	(1)	(2)
Comparable income tax expense attributable to TransAlta shareholders	3	14
Comparable effective tax rate on earnings attributable to TransAlta shareholders (%)	10	27

The comparable income tax expense attributable to TransAlta shareholders for the three months ended March 31, 2016 decreased compared to the same period in 2015 primarily due to lower comparable earnings.

The comparable effective tax rate on earnings attributable to TransAlta shareholders decreased for the three months ended March 31, 2016 compared to the same period in 2015 primarily due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which the pre-tax income was earned.

(1) 2015 restated to reflect prior period correction. Refer to the Accounting Changes section of this MD&A.

During the three months ended March 31, 2016, we reversed a previous writedown of deferred income tax assets of \$23 million (March 31, 2015 - \$15 million) of which \$10 million represented an adjustment in respect of deferred income tax of prior periods. The remaining deferred income tax assets mainly relate to the tax benefits of losses associated with our directly owned U.S. operations. We had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from our directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. We recognized other comprehensive income during the period that has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

In order to give effect to the sale of an economic interest in Australian assets with TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition in the first quarter of 2015 of a \$55 million deferred tax liability on TransAlta's investment in a subsidiary. The deferred tax liability had not been recognized previously, since prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

Capital Structure and Liquidity

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

As at	March 31, 2016		Dec. 31, 2015	
	\$	%	\$	%
Recourse debt - CAD debentures	1,045	12	1,044	12
Recourse debt - U.S. senior notes	2,073	24	2,221	26
Credit facilities	-	-	315	4
U.S. tax equity financing	45	1	50	1
Other	34	-	17	-
Less: cash and cash equivalents	(30)	-	(54)	(1)
Less: fair value asset of hedging instruments on debt	(125)	(1)	(190)	(2)
Net recourse debt	3,042	36	3,403	40
Non-recourse debt	754	9	766	9
Finance lease obligations	79	1	82	1
Total net debt	3,875	46	4,251	50
Non-controlling interests	1,164	14	1,029	12
Equity attributable to shareholders				
Common shares	3,093	37	3,075	35
Preferred shares	942	11	942	11
Contributed surplus, deficit, and accumulated other comprehensive income	(657)	(8)	(656)	(8)
Total capital	8,417	100	8,641	100

During the quarter, we paid out the credit facilities balance of approximately \$315 million through a combination of cash flows from operations and cash proceeds of \$173 million received from the sale to TransAlta Renewables of an economic interest in the 506 MW Sarnia cogeneration facility and two renewable energy facilities that closed Jan. 6, 2016.

The weakening of the US dollar decreased our long-term debt balances by \$155 million since Dec. 31, 2015. Almost all of our U.S.-denominated debt is hedged either through financial contracts or net investments in our U.S. operations. During the quarter, these changes in our U.S.-denominated debt were offset as follows:

3 months ended March 31	2016
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	(81)
Foreign currency cash flow hedges on debt	(68)
Economic hedges and other	(6)
Total	(155)

During the period through Dec. 31, 2018, we have approximately \$1.6 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising debt secured by some of our contracted assets in Canada and the U.S. We also expect to continue our de-leveraging strategy and most of our free cash flow over the next three years, after funding of the South Hedland project, will be allocated to debt reduction.

Credit Facilities

Our credit facilities provide us with significant liquidity. At March 31, 2016, we had a total of \$2.1 billion (Dec. 31, 2015 - \$2.2 billion) of committed credit facilities, of which \$1.5 billion (Dec. 31, 2015 - \$1.3 billion) was available. We are in compliance with the terms of the credit facilities. At March 31, 2016, the \$0.6 billion (Dec. 31, 2015 - \$0.9 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2015 - \$0.3 billion) and letters of credit of \$0.6 billion (Dec. 31, 2015 - \$0.6 billion). These facilities are comprised of a \$1.5 billion committed syndicated bank facility expiring in 2019, and four bilateral credit facilities expiring in 2017. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Share Capital

On March 17, 2016, we announced that 1,824,620 of our 12 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares. Refer to the Highlights and Significant and Subsequent Events sections of this MD&A for further details.

The following table outlines the common and preferred shares issued and outstanding:

As at	May 2, 2016	March 31, 2016	Dec. 31, 2015
	Number of shares (millions)		
Common shares issued and outstanding, end of period	287.9	287.9	284.0
Preferred shares			
Series A	10.2	10.2	12.0
Series B	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, 2016, we own 64.0 per cent (Dec. 31, 2015 - 66.6 per cent) of TransAlta Renewables. On Jan. 6, 2016, we completed the sale of an economic interest of the 506 MW Sarnia cogeneration facility and of two renewable energy facilities with total capacity of 105 MW for \$540 million.

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.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

3 months ended March 31	2016	2015
Interest on debt	60	57
Capitalized interest	(3)	(3)
Interest on finance lease obligations	1	1
Accretion of provisions	6	5
Net interest expense	64	60

For the three months ended March 31, 2016, net interest expense increased compared to the same period in 2015, primarily due to higher interest expense on foreign-denominated debt due to the stronger US dollar relative to the same period last year.

Dividends to Shareholders

On Jan. 14, 2016, we announced a reduction of our common share dividend from \$0.72 annually to \$0.16 annually and the suspension of the Premium DividendTM, Dividend Reinvestment and Optional Common Share Purchase Plan effective immediately. These actions were taken as part of a plan to maximize our long-term financial flexibility. Declaration of dividends is at the discretion of the Board.

On Feb. 16, 2016, we declared a quarterly dividend of \$0.04 per share on common shares, payable on April 1, 2016 and a quarterly dividend of \$0.2875 per share on the Series A and 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 March 31, 2016.

On April 21, 2016, we declared a quarterly dividend of \$0.04 per share on common shares, payable on July 1, 2016 and a quarterly dividend of \$0.16931 per share on the Series A preferred shares, \$0.15940 per share on the Series B preferred shares, \$0.2875 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, 2016.

Non-Controlling Interests

Comparable earnings attributable to non-controlling interests for the three months ended March 31, 2016 increased \$12 million to \$26 million compared to the same period in 2015, primarily due to the additional common shares issued to the public by TransAlta Renewables in relation to the Australian and Canadian portfolio dropdowns in addition to higher earnings of TransAlta Renewables on a larger asset base, partially offset by unrealized foreign exchange losses on some of the financial interests in the Australian Assets.

Financial Position

The following charts highlight significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2015 to March 31, 2016:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	(24)	Timing of receipts and payments, repayment of credit facilities
Trade and other receivables	(110)	Timing of customer receipts, offset by increases in collateral paid (\$27 million) and seasonality of revenue
Finance lease receivables (long-term)	(44)	Unfavourable changes in foreign exchange rates
Property, plant, and equipment, net	(143)	Depreciation for the period (\$139 million), unfavourable changes in foreign exchange rates (\$65 million), and revisions to decommissioning and restoration costs (\$19 million), partially offset by additions (\$85 million)
Risk management assets (current and long-term)	(74)	Changes in foreign exchange rates
Other	2	
Total decrease in assets	(393)	

	Increase/ (decrease)	Primary factors explaining change
Credit facilities, long-term debt, and finance lease obligations (including current portion)	(465)	Favourable effects of changes in foreign exchange rates (\$155 million) and credit facility repayment (\$315 million)
Decommissioning and other provisions (current and long-term)	(42)	Increase in risk-adjusted discount rates
Defined benefit obligation and other long-term liabilities	23	Decrease in risk free discount rates
Risk management liabilities (current and long-term)	(31)	Contract settlements
Equity attributable to shareholders	17	Net earnings (\$64 million), issuance of common shares (\$18 million), and gains on cash flow hedges (\$43 million), partially offset by net losses on translating net assets of foreign operations (\$52 million) and actuarial losses on defined benefit plans (\$20 million)
Non-controlling interests	135	Sale of economic interests to TransAlta Renewables, partially offset by net loss for the period, and distributions paid and payable to non-controlling interests
Other	(30)	
Total decrease in liabilities and equity	(393)	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2016 compared to the same period in 2015:

3 months ended March 31	2016	2015	Primary factors explaining change
Cash and cash equivalents, beginning of period	54	43	
Provided by (used in):			
Operating activities	275	153	Favourable change in non-cash working capital of \$143 million, partially offset by lower cash earnings
Investing activities	(67)	(143)	Lower additions to property, plant, and equipment, realized gains on financial instruments, and a higher decrease in finance lease receivables as a result of the Poplar Creek restructuring during late 2015
Financing activities	(230)	7	Repayment of credit facilities, an increase in distributions to non-controlling interests, and lower realized gains on financial instruments, partially offset by the proceeds from the sale of additional non-controlling interests
Translation of foreign currency cash	(2)	1	
Cash and cash equivalents, end of period	30	61	

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, 2016, we provided letters of credit totalling \$588 million (Dec. 31, 2015 - \$575 million) and cash collateral of \$101 million (Dec. 31, 2015 - \$74 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.

Earnings and Other Measures on a Comparable Basis

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.

Each business segment assumes responsibility for its operating results measured to gross margin and operating income. Operating income and gross margin provides management and investors with a measurement of operating performance that is readily comparable from period to period.

In calculating these items, we exclude certain items as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

During 2016, prior period restatements were made to the 2015 period. Refer to the Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable EBITDA and comparable earnings for the three months ended March 31, 2016 and the same period in 2015 are as follows. References are to the reconciliation presented on the following pages.

3 months ended March 31			2016	2015
Reference number	Adjustment	Segment		
Reclassifications:				
1	Finance lease income used as a proxy for operating revenue	Australian Gas	13	12
		Canadian Gas	3	1
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	14	1
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	15	14
Adjustments (increasing (decreasing) earnings to arrive at comparable results):				
4	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	5	31
5	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	-	1
6	Restructuring expense	Canadian Coal	-	7
7	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	(2)	-
8	Net tax effect on comparable adjustments subject to tax	Unassigned	-	(13)
9	Deferred income tax rate adjustment	Unassigned	1	-
10	Reversal of writedown of deferred income tax assets	Unassigned	(23)	(15)
11	Income tax expense related to temporary difference on investment in subsidiary (<i>Restated</i>)*	Unassigned	-	55
12	Non-comparable items attributable to non-controlling interests	Unassigned	(29)	-

* 2015 restated to reflect prior period correction. Refer to the Accounting Changes section of this MD&A.

A reconciliation of comparable results to reported results for the three months ended March 31, 2016 and the same period in 2015 is as follows:

	3 months ended March 31, 2016				3 months ended March 31, 2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	568	30 ^(1,2)	5 ⁽⁴⁾	603	593	14 ^(1,2)	31 ⁽⁴⁾	638
Fuel and purchased power	208	(15) ⁽³⁾	-	193	237	(14) ⁽³⁾	-	223
Gross margin	360	45	5	410	356	28	31	415
Operations, maintenance, and administration	123	-	-	123	134	-	(1) ⁽⁵⁾	133
Restructuring provision	-	-	-	-	7	-	(7) ⁽⁶⁾	-
Taxes, other than income taxes	8	-	-	8	7	-	-	7
EBITDA	229	45	5	279	208	28	39	275
Depreciation and amortization	122	29 ^(2,3)	-	151	133	15 ^(2,3)	-	148
Operating income	107	16	5	128	75	13	39	127
Finance lease income	16	(16) ⁽¹⁾	-	-	13	(13) ⁽¹⁾	-	-
Foreign exchange gain (loss)	(6)	-	(2) ⁽⁷⁾	(8)	1	-	-	1
Earnings before interest and taxes	117	-	3	120	89	-	39	128
Net interest expense	64	-	-	64	60	-	-	60
Income tax expense (recovery)	(18)	-	22 ^(8,9,10)	4	43	-	(27) ^(8,10,11)	16
Net earnings (loss)	71	-	(19)	52	(14)	-	66	52
Non-controlling interests	(3)	-	29 ⁽¹²⁾	26	14	-	-	14
Net earnings (loss) attributable to TransAlta shareholders	74	-	(48)	26	(28)	-	66	38
Preferred share dividends	12	-	-	12	12	-	-	12
Net earnings (loss) attributable to common shareholders	62	-	(48)	14	(40)	-	66	26
Weighted average number of common shares outstanding in the period	288			288	277			277
Net earnings (loss) per share attributable to common shareholders	0.22			0.05	(0.14)			0.09

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2015 Annual Integrated Report and Note 7 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2016 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2015 Annual Integrated Report and Note 8 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, 2015.

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.

We may also have various 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 must be derived by reference to a forecast that is based on a combination of external and internal fundamental modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for specified prices with counterparties that we believe to be creditworthy.

As at March 31, 2016, total Level III financial instruments had a net asset carrying value of \$576 million (Dec. 31, 2015 - \$542 million net asset). The increase during the period is attributable to a decrease in estimated long-term power prices on a 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, and maturities of gas contracts, partially offset by unfavourable changes in foreign exchange rates due to the weakening of the US dollar relative to the Canadian dollar.

2016 Financial Outlook

Despite continuing low prices in Alberta and Pacific Northwest, our expected key financial target ranges for 2016 remain as previously disclosed:

Measure	Target
Comparable EBITDA	\$990 million to \$1,100 million
Comparable FFO	\$755 million to \$835 million
Comparable FCF	\$250 million to \$300 million
Dividend	\$0.16 per share, 15 to 18 per cent payout of Comparable FCF

Market

For 2016, power prices in Alberta are expected to be substantially lower than 2015 as a result of persistent low natural gas prices, low demand growth, and the current level of supply. However, prices can vary based on supply and weather conditions. In the Pacific Northwest we expect power prices to be lower as well due to low natural gas prices. We do not have significant uncontracted positions in other jurisdictions.

Operations

Availability and Operating Costs

Availability of our coal fleet in Canada is expected to be in the range of 87 to 89 per cent in 2016. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent. All of our businesses are sustaining cost reduction initiatives completed in 2015. We continue to explore ways to further reduce our costs and be more competitive.

Contracted Cash Flows

As a result of Alberta PPAs and long-term contracts, approximately 75 per cent of our capacity is contracted over the next two years. This is reduced to 65 per cent when our Alberta PPAs for Sundance units 1 and 2 expire in 2017. 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, approximately 88 per cent of our 2016 capacity was contracted. The average prices of our short-term physical and financial contracts for 2016 are approximately \$50 per MWh in Alberta and approximately US\$45 per MWh in the Pacific Northwest.

Fuel Costs

Mining costs at our Alberta coal mine are expected to decrease in 2016 due to improved efficiency, lower diesel cost, and production improvements. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2016, on a standard cost per tonne basis, are expected to be one to four per cent lower than 2015 unit costs.

In the Pacific Northwest, our U.S. Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal is purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2016 is expected to decrease by approximately three per cent due to lower diesel surcharge costs on coal deliveries.

The value of coal inventories is assessed for impairment at the end of each reporting period.

Most of our generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provision, we typically purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

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

Energy Marketing

EBITDA from our Energy Marketing Segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2016 objective for Energy Marketing is to contribute between \$60 million to \$80 million in gross margin for the year. Gross margin in the first quarter was in line with our expectations.

Exposure to Fluctuations in Foreign Currencies

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

Net Interest Expense

Net interest expense for 2016 is expected to be lower than in 2015 primarily due to higher 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. Most of our debt is at fixed interest rates.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. Free cash flows generated by the business should be sufficient to support the construction of the South Hedland power station in 2016.

Income Taxes

The effective tax rate on earnings, excluding non-comparable items for 2016, is expected to be approximately 10 to 15 per cent, which is lower than the statutory tax rate of 27 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital Expenditures

Our major projects are focused on sustaining our current operations and supporting our growth strategy.

Growth and Major Project Expenditures

A summary of the significant growth and major projects that are in progress is outlined below:

Project	Total Project		2016	Target	Details
	Estimated spend	Spent to date ⁽¹⁾	Estimated spend	completion date	
South Hedland power station ⁽²⁾	593	274	119	Q2 2017	150 MW combined cycle power plant
Solomon load bank facility ⁽³⁾	5	2	3	Q2 2016	Installation of 20 MW load bank facility required to complete the Solomon power station
Transmission	Not applicable ⁽⁴⁾		13	Ongoing	Regulated transmission that receives a return on investment
Total	598	276	135		

(1) As at March 31, 2016.

(2) Estimated project spend is AUD\$570 million. Total estimated project spend is stated in CAD\$ and includes estimated capital interest costs. The total estimated project spend may change due to fluctuation in foreign exchange rates.

(3) Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable. The total estimated project spend may change due to fluctuations in foreign exchange rates.

(4) Transmission projects are aggregated and develop on an ongoing basis. Consequently, discrete project spend is not available.

Sustaining and Productivity Expenditures

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

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

Category	Description	Spent to date ⁽¹⁾	Expected spend in 2016
Routine capital ⁽²⁾	Capital required to maintain our existing generating capacity	10	100 - 105
Planned major maintenance	Regularly scheduled major maintenance	46	155 - 165
Mine capital	Capital related to mining equipment and land purchases	-	30 - 35
Finance leases	Payments on finance leases	3	15 - 20
Total sustaining capital excluding flood-recovery capital		59	300 - 325
Flood-recovery capital	Capital arising from the 2013 Alberta flood	-	5
Total sustaining capital		59	305 - 330
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	-	10 - 15
Total sustaining and productivity capital		59	315 - 345

Planned major outages for 2016 include full major turnarounds of two Canadian Coal units that we operate, and two that our partners operate. During the first quarter, we replaced one planned full scope major turnaround with limited scope major turnaround work on two units that we operate. Our planned outages also includes significant work at our hydro facilities, including a stator/generator replacement.

One of our partners completed a major turnaround of one Canadian Coal unit that we do not operate in the first quarter of 2016, and in April we completed the planned outage of a second unit that we operate. The two limited scope turnaround projects were also completed in the first quarter. As a result, we now have only one more planned major outage at the Canadian Coal facilities that we operate for the rest of this year, and one at units that our partners operate.

During the first quarter of 2016, we reduced our estimate of sustaining capital expenditures for the full year from our previous estimate by approximately \$25 million, to reflect the reduced scope of a major turnaround, deferral of the Ghost river diversion project to a subsequent year, and other savings and deferrals.

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, and limited-scope major maintenance projects executed during unplanned outages, is estimated as follows for 2016:

	Coal	Gas and Renewables	Total	Lost to date ⁽¹⁾
GWh lost	825 - 835	135 - 145	960 - 980	357

The reduction in estimated lost production from previous estimates is attributable to the reduced maintenance activities described above.

(1) As at March 31, 2016.

(2) Includes hydro life extension spend.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities. We have access to approximately \$1.5 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.

Accounting Changes

A. Current Accounting Changes**I. Operating and Reportable Segments**

Beginning this quarter, we have chosen to disaggregate presentation of the Gas reportable segment into its two operating segments, Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been re-allocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Restatement of a Prior Quarter

During the fourth quarter of 2015, we restated the statement of earnings of the first quarter of 2015, to increase non-comparable deferred tax expense by \$47 million. As a result, net earnings attributable to common shareholders of the first quarter of 2015 has decreased from \$7 million to a net loss of \$40 million. The adjustment is due to the correction of the tax basis of an internally transferred asset as part of the reorganization of companies giving effect to the sale of an economic interest in Australian Assets to TransAlta Renewables which closed during the second quarter of 2015. Comparative information of the first quarter of 2015 presented in this document has been adjusted accordingly.

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied include IFRS 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers*, and IFRS 16 *Leases*. Refer to Note 3 of the most recent annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at 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 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
Comparable net earnings (loss) attributable to common shareholders	(44)	(33)	3	14
Net earnings (loss) per share attributable to common shareholders, basic and diluted ⁽¹⁾	(0.47)	0.55	(0.02)	0.22
Comparable net earnings (loss) per share, basic and diluted ⁽¹⁾	(0.16)	(0.12)	0.01	0.05
	Q2 2014	Q3 2014	Q4 2014	Q1 2015
				<i>*Restated</i>
Revenues	491	639	718	593
Comparable EBITDA	213	212	301	275
Comparable FFO	154	145	225	211
Net earnings (loss) attributable to common shareholders	(50)	(6)	148	(40)
Comparable net earnings (loss) attributable to common shareholders	(12)	(13)	46	26
Net earnings (loss) per share attributable to common shareholders, basic and diluted ⁽¹⁾	(0.18)	(0.03)	0.54	(0.14)
Comparable net earnings (loss) per share, basic and diluted ⁽¹⁾	(0.04)	(0.05)	0.17	0.09

* See Accounting Changes for restatement.

(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.

Comparable net earnings, comparable EBITDA, and comparable 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. Market volatility can also impact quarterly contributions from our Energy Marketing Segment. Following sales of non-controlling interest in TransAlta Renewables in the second quarter of 2015, the fourth quarter of 2015, and the first quarter of 2016, an increasing portion of earnings is attributable to non-controlling interests.

Revenues are impacted by market and operational factors listed above, and by changes in future power prices in the Pacific Northwest, which cause de-designated and economic hedges in the region to fluctuate in value. These hedges significantly depreciated in the second quarter of 2014 and first half of 2015, and significantly increased in value in the second half of 2014 over the third quarter of 2015. Revenues in the fourth quarter of 2015 was also impacted by a significant increase to a provision related to Force Majeure events associated mostly to prior years.

Net earnings attributable to common shareholders have 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;
- MSA provision in the third quarter of 2015;
- writedown of deferred tax assets in the second quarter of 2014, a recovery in the fourth quarter of 2014, a recovery in the third quarter of 2014, and a recovery in the first quarter 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 transaction in the first and second quarters of 2015; and
- effects of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first 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.

During the first quarter of 2016, we completed the implementation of a new energy trading and risk management system. In connection with the implementation, we updated the processes that constitute our internal control over financial reporting, as necessary, to accommodate related changes to our business processes and accounting procedures.

Except as otherwise described above, there have been no other changes in our internal control over financial reporting during the three months ended March 31, 2016, that has materially affected, or is 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 of March 31, 2016, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

TransAlta Corporation

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

(Unaudited)	3 months ended March 31	
	2016	2015 (Restated)*
Revenues	568	593
Fuel and purchased power	208	237
Gross margin	360	356
Operations, maintenance, and administration	123	134
Depreciation and amortization	122	133
Restructuring	-	7
Taxes, other than income taxes	8	7
Operating income	107	75
Finance lease income	16	13
Net interest expense (Note 4)	(64)	(60)
Foreign exchange gains (losses)	(6)	1
Earnings before income taxes	53	29
Income tax expense (recovery) (Note 5)	(18)	43
Net earnings (loss)	71	(14)
Net earnings (loss) attributable to:		
TransAlta shareholders	74	(28)
Non-controlling interests (Note 6)	(3)	14
	71	(14)
Net earnings (loss) attributable to TransAlta shareholders	74	(28)
Preferred share dividends (Note 12)	12	12
Net income (loss) attributable to common shareholders	62	(40)
Weighted average number of common shares outstanding in the period (millions)	288	277
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.22	(0.14)

* See Note 2(A) for prior period restatements.
See accompanying notes.

TransAlta Corporation

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

	3 months ended March 31	
	2016	2015
<i>Unaudited</i>		<i>(Restated)*</i>
Net earnings (loss)	71	(14)
Net actuarial losses on defined benefit plans, net of tax ⁽¹⁾	(20)	(14)
Gains on derivatives designated as cash flow hedges, net of tax ⁽²⁾	-	2
Total items that will not be reclassified subsequently to net earnings	(20)	(12)
Gains (losses) on translating net assets of foreign operations ⁽³⁾	(124)	110
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax ⁽⁴⁾	62	(64)
Gains on derivatives designated as cash flow hedges, net of tax ⁽⁵⁾	8	152
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax ⁽⁶⁾	38	(75)
Total items that will be reclassified subsequently to net earnings	(16)	123
Other comprehensive income (loss)	(36)	111
Total comprehensive income	35	97
Total comprehensive income attributable to:		
TransAlta shareholders	35	80
Non-controlling interests (Note 6)	-	17
	35	97

* See Note 2(A) for prior period restatements.

(1) Net of income tax recovery of 7 for the three months ended March 31, 2016 (2015 - 5 recovery).

(2) Net of income tax expense of nil for the three months ended March 31, 2016 (2015 - 1 expense).

(3) Net of income tax expense of \$10 million for the three months ended March 31, 2016 (2015 - nil).

(4) Net of income tax expense of 4 for the three months ended March 31, 2016 (2015 - 9 recovery).

(5) Net of income tax expense of 25 for the three months ended March 31, 2016 (2015 - 47 expense).

(6) Net of income tax recovery of 3 for the three months ended March 31, 2016 (2015 - 25 expense).

See accompanying notes.

TransAlta Corporation

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

<i>Unaudited</i>	March 31, 2016	Dec. 31, 2015
Cash and cash equivalents	30	54
Trade and other receivables (Note 8)	457	567
Prepaid expenses	29	26
Risk management assets (Notes 7 and 8)	250	298
Inventory	219	219
	985	1,164
Long-term portion of finance lease receivables	731	775
Property, plant, and equipment (Note 9)		
Cost	12,765	12,854
Accumulated depreciation	(5,735)	(5,681)
	7,030	7,173
Goodwill	464	465
Intangible assets	363	369
Deferred income tax assets	74	71
Risk management assets (Notes 7 and 8)	771	797
Other assets	136	133
Total assets	10,554	10,947
Accounts payable and accrued liabilities	336	334
Current portion of decommissioning and other provisions	166	166
Risk management liabilities (Notes 7 and 8)	153	200
Income taxes payable	1	3
Dividends payable (Note 11)	26	63
Current portion of long-term debt and finance lease obligations (Note 10)	103	87
	785	853
Credit facilities, long-term debt, and finance lease obligations (Note 10)	3,927	4,408
Decommissioning and other provisions	190	232
Deferred income tax liabilities	654	647
Risk management liabilities (Notes 7 and 8)	85	69
Defined benefit obligation and other long-term liabilities	371	348
Equity		
Common shares (Note 11)	3,093	3,075
Preferred shares (Note 12)	942	942
Contributed surplus	9	9
Deficit	(980)	(1,018)
Accumulated other comprehensive income	314	353
Equity attributable to shareholders	3,378	3,361
Non-controlling interests (Note 6)	1,164	1,029
Total equity	4,542	4,390
Total liabilities and equity	10,554	10,947

Commitments and contingencies (Note 13)

See accompanying notes.

TransAlta Corporation

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

3 months ended March 31, 2016

<i>Unaudited</i>	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 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	-	-	-	(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.

3 months ended March 31, 2015

<i>Unaudited</i>	Common shares	Preferred shares	Contributed surplus	Deficit (Restated)*	Accumulated other comprehensive income (loss)	Attributable to shareholders (Restated)*	Attributable to non-controlling interests	Total (Restated)*
Balance, Dec. 31, 2014	2,999	942	9	(770)	104	3,284	594	3,878
Net earnings (loss)	-	-	-	(28)	-	(28)	14	(14)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	46	46	-	46
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	76	76	3	79
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(14)	(14)	-	(14)
Total comprehensive income (loss)				(28)	108	80	17	97
Common share dividends	-	-	-	(50)	-	(50)	-	(50)
Preferred share dividends	-	-	-	(12)	-	(12)	-	(12)
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(20)	(20)
Common shares issued	20	-	-	-	-	20	-	20
Balance, March 31, 2015	3,019	942	9	(860)	212	3,322	591	3,913

* See Note 2(A) for prior period restatements.

See accompanying notes.

TransAlta Corporation

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

<i>Unaudited</i>	3 months ended March 31	
	2016	2015
Operating activities		
Net earnings (loss)	71	(14)
Depreciation and amortization	136	147
Accretion of provisions	6	5
Decommissioning and restoration costs settled	(3)	(5)
Deferred income tax expense (recovery) (Note 5)	(23)	37
Unrealized (gains) losses from risk management activities	(2)	36
Unrealized foreign exchange losses	5	7
Provisions	1	(9)
Other non-cash items	(10)	(2)
Cash flow from operations before changes in working capital	181	202
Change in non-cash operating working capital balances	94	(49)
Cash flow from operating activities	275	153
Investing activities		
Additions to property, plant, and equipment (Note 9)	(85)	(124)
Additions to intangibles	(4)	(6)
Proceeds on sale of property, plant, and equipment	1	1
Realized gains (losses) on financial instruments	2	(6)
Net increase in collateral paid to counterparties	-	(4)
Decrease in finance lease receivable	14	1
Other	1	-
Change in non-cash investing working capital balances	4	(5)
Cash flow used in investing activities	(67)	(143)
Financing activities		
Net increase (decrease) in borrowings under credit facilities (Note 10)	(315)	583
Repayment of long-term debt	(7)	(633)
Issuance of long-term debt (Note 10)	17	45
Dividends paid on common shares (Note 11)	(34)	(30)
Dividends paid on preferred shares (Note 12)	(12)	(12)
Net proceeds on sale of non-controlling interest in subsidiary (Note 3)	162	-
Realized gains on financial instruments	-	76
Distributions paid to subsidiaries' non-controlling interests (Note 6)	(39)	(19)
Decrease in finance lease obligation	(3)	(3)
Other	1	-
Cash flow from (used in) financing activities	(230)	7
Cash flow from (used in) operating, investing, and financing activities	(22)	17
Effect of translation on foreign currency cash	(2)	1
Increase (decrease) in cash and cash equivalents	(24)	18
Cash and cash equivalents, beginning of period	54	43
Cash and cash equivalents, end of period	30	61
Cash income taxes paid	8	14
Cash interest paid	21	41

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 assets and liabilities, 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 2, 2016.

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. An additional judgment applied in the first quarter of 2016 with respect to operating and reportable segments is described in Note 2(A).

2. Significant Accounting Policies

A. Current Accounting Changes

I. Operating and Reportable Segments

Beginning this quarter, the Corporation has chosen to disaggregate presentation of the previous Gas reportable segment into its two operating segments; Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management’s internal monitoring practices. Comparative segmented results for 2015 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Restatement of a Prior Quarter

During the fourth quarter of 2015, the Corporation restated the statement of earnings of the first quarter of 2015, to increase deferred tax expense by \$47 million. As a result, net earnings attributable to common shareholders of the first quarter of 2015 has decreased from \$7 million to a net loss of \$40 million. The adjustment is due to the correction of the tax basis of an internally transferred asset as part of the reorganization of companies giving effect to the sale of an economic interest in Australian assets to TransAlta Renewables Inc. ("TransAlta Renewables"), which closed during the second quarter of 2015. Comparative information of the first quarter of 2015 presented in this document has been adjusted accordingly.

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 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.

3. Significant Events

Investment in Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility by TransAlta Renewables

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Sarnia cogeneration plant, Le Nordais wind farm, and Ragged Chute hydro facility (the "Canadian Assets") for a combined value of approximately \$540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Quebec. The transaction was originally announced on Nov. 23, 2015. The Corporation will continue to own, manage, and operate the Canadian Assets.

As consideration, TransAlta Renewables provided to the Corporation \$173 million in cash, issued 15,640,583 common shares with an aggregate value of \$152 million, and issued a \$215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30th and December 31st and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of \$13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation through issuance of common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of \$9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received one common share of TransAlta Renewables and a cash dividend equivalent payment of \$0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of \$1 million. Share issuance costs amounted to \$8 million, net of \$2 million income tax recovery. On Jan. 6, 2016, TransAlta Renewables declared a dividend increase of 5 per cent.

4. Net Interest Expense

The components of net interest expense are as follows:

3 months ended March 31	2016	2015
Interest on debt	60	57
Capitalized interest	(3)	(3)
Interest on finance lease obligations	1	1
Accretion of provisions	6	5
Net interest expense	64	60

5. Income Taxes

The components of income tax expense (recovery) are as follows:

3 months ended March 31	2016	2015 (Restated)*
Current income tax expense	5	7
Adjustments in respect of current income tax of prior periods	-	(1)
Deferred income tax recovery related to the origination and reversal of temporary differences	(1)	(3)
Deferred income tax expense related to temporary difference on investment in subsidiary ⁽¹⁾	-	55
Deferred income tax expense resulting from changes in tax rates or laws ⁽²⁾	1	-
Deferred income tax recovery arising from the writedown of deferred income tax assets ⁽³⁾	(23)	(15)
Income tax expense (recovery)	(18)	43

* See Note 2(A) for prior period restatements.

(1) In order to give effect to the sale of an economic interest in Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a \$55 million deferred tax liability on TransAlta's investment in a subsidiary. The deferred tax liability had not been recognized previously, as prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

(2) Impact of increase in New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016.

(3) During the three months ended March 31, 2016, the Corporation reversed a previous writedown of deferred income tax assets of \$23 million (2015 - \$15 million) of which \$10 million represented an adjustment in respect of deferred income tax of prior periods. The remaining 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.

Presented in the Condensed Consolidated Statements of Earnings as follows:

3 months ended March 31	2016	2015 (Restated)*
Current income tax expense	5	6
Deferred income tax expense (recovery)	(23)	37
Income tax expense (recovery)	(18)	43

* See Note 2(A) for prior period restatements.

6. Non-Controlling Interests

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

Amounts attributable to the non-controlling interests include the 17 per cent non-controlling interest in its Kent Hills wind farm.

The Corporation's share of ownership and equity participation were as follows over the current and comparative periods:

Period	Ownership and voting rights percentage	Equity participation percentage
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 and thereafter	64.0	59.8

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

3 months ended March 31	2016	2015
Revenues	68	68
Net earnings (loss)	(35)	21
Total comprehensive income (loss)	(36)	21
Amounts attributable to the non-controlling interests:		
Net earnings (loss)	(14)	7
Total comprehensive income (loss)	(14)	7
Distributions paid to non-controlling interests	20	8

As at	March 31, 2016	Dec. 31, 2015
Current assets	86	74
Long-term assets	3,754	3,262
Current liabilities	(183)	(190)
Long-term liabilities	(1,405)	(1,120)
Total equity	(2,252)	(2,026)
Equity attributable to non-controlling interests	(927)	(787)
Non-controlling interests share (per cent)	40.2	38.0

B. TransAlta Cogeneration L.P.

3 months ended March 31	2016	2015
Revenues	77	75
Net earnings	21	15
Total comprehensive income	27	19
Amounts attributable to the non-controlling interest:		
Net earnings	11	7
Total comprehensive income	14	10
Distributions paid to the non-controlling interest	19	12

As at	March 31, 2016	Dec. 31, 2015
Current assets	80	82
Long-term assets	516	535
Current liabilities	(77)	(75)
Long-term liabilities	(42)	(54)
Total equity	(477)	(488)
Equity attributable to the non-controlling interest	(237)	(242)
Non-controlling interest share (per cent)	49.99	49.99

7. Financial Instruments

A. Financial Assets and Liabilities – Measurement

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

B. Fair Value of Financial Instruments

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

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

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

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

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

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

c. Level III

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

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

The Corporation also has 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 (the "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. The 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 Description	March 31, 2016		Dec. 31, 2015	
	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	836	+114 -177	863	+125 -186
Long-term power sale - Alberta	(5)	+11 -9	(13)	+13 -7
Unit contingent power purchases	(47)	+6 -4	(70)	+9 -8
Structured products - Eastern U.S.	34	+9 -9	18	+6 -4
Hydro slice products - Western U.S.	(8)	+1 -1	(6)	+1 -4
Others	(1)	+2 -3	(3)	+2 -2

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: 280 MW through Nov. 30, 2016, 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 2017, 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 MWh used in determining the Level III base fair value at March 31, 2016 are US\$28 - US\$45 (Dec. 31, 2015 - US\$28 - US\$45).

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2015 to March 31, 2016, the base fair value and the sensitivity values have decreased by approximately \$46 million and \$10 million, respectively, as a result of the currency movement.

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, 2016 are \$84 - \$96 (Dec. 31, 2015 - \$86 - \$93).

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.

In particular, a one standard deviation movement upward and downward in the volumetric and price discount rates was assessed. 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, 2016 are 0 per cent to 2.8 per cent (Dec. 31, 2015 - 0 per cent to 2.8 per cent) and 1.7 per cent to 7.4 per cent (Dec. 31, 2015 - 1.7 per cent to 7.4 per cent), respectively.

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, 2016 are 82 per cent to 129 per cent and 65 per cent to 110 per cent (Dec. 31, 2015 - 85 per cent to 116 per cent and 65 per cent to 109 per cent), respectively.

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, 2016 are 18 per cent to 52 per cent and 39 per cent to 80 per cent (Dec. 31, 2015 - 18 per cent to 71 per cent and 39 per cent to 80 per cent), respectively.

v. Hydro Slice Products - Western U.S.

The Corporation has agreed to purchase power contingent upon the actual generation of specific hydro units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed capacity payment. The contracts are accounted for as held for trading.

The key unobservable inputs used in the valuations are delivered volume expectations. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements. This analysis is based on historical production of the generation units for available history. Volumes used in the Level III base fair value measurement at March 31, 2016 are within the 50th percentile of the historical production (Dec. 31, 2015 - 50th percentile).

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.

The following tables summarize the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the three months ended March 31, 2016 and 2015, respectively:

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2015	-	(58)	640	-	128	(98)	-	70	542
Changes attributable to:									
Market price changes on existing contracts	-	30	66	-	34	(22)	-	64	44
Market price changes on new contracts	-	1	-	-	3	4	-	4	4
Contracts settled	-	4	(13)	-	(82)	65	-	(78)	52
Change in foreign exchange rates	-	4	(68)	-	(4)	2	-	-	(66)
Net risk management assets (liabilities) at March 31, 2016	-	(19)	625	-	79	(49)	-	60	576
Additional Level III information:									
Losses recognized in OCI			(2)			-			(2)
Total gains (losses) included in earnings before income taxes			13			(16)			(3)
Unrealized gains included in earnings before income taxes relating to net liabilities held at March 31, 2016			-			49			49

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	-	17	69	-	11	(9)	-	28	60
Market price changes on new contracts	-	-	-	-	(5)	(2)	-	(5)	(2)
Contracts settled	-	5	(7)	-	(79)	42	-	(74)	35
Change in foreign exchange rates	-	(6)	47	-	9	(4)	-	3	43
Net risk management assets (liabilities) at March 31, 2015	-	(43)	423	-	116	(70)	-	73	353
Additional Level III information:									
Gains recognized in OCI			116			-			116
Total gains (losses) included in earnings before income taxes			7			(15)			(8)
Unrealized gains included in earnings before income taxes relating to net liabilities held at March 31, 2015			-			27			27

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2016 are primarily attributable to the following factors:

- increases in value related to market movements for power contracts in Alberta (Level II hedges);
- 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;
- maturities and increases in value related to market movements for power contracts in the Pacific Northwest (Level II non-hedge); and
- settlement and maturities of unit contingent power purchases described in the section (B)(I)(c)(iii) of this note (Level III non-hedges)

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy marketing transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks. Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

Other risk management assets and liabilities with a total net asset fair value of \$147 million as at March 31, 2016 (Dec. 31, 2015 - \$214 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, 2016 are primarily attributable to the weakening of the US dollar relative to the Canadian dollar on the Corporation's foreign currency hedges.

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 ⁽¹⁾ - March 31, 2016	-	3,488	-	3,488	3,886
Long-term debt ⁽¹⁾ - Dec. 31, 2015	-	4,067	-	4,067	4,344

(1) Includes current portion and excludes \$65 million (Dec. 31, 2015 - \$69 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 and other accounts receivable, accounts payable and accrued liabilities, 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	2016	2015
Unamortized net gain at beginning of period	202	188
New inception gains	2	1
Change in foreign exchange rates	(12)	16
Amortization recorded in net earnings during the period	(18)	(20)
Unamortized net gain at end of period	174	185

8. Risk Management Activities

A. Net Risk Management Assets and Liabilities

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

As at March 31, 2016

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	59	-	29	88
Long-term	-	547	-	1	548
Net commodity risk management assets	-	606	-	30	636
Other					
Current	4	8	-	(3)	9
Long-term	-	137	5	(4)	138
Net other risk management assets (liabilities)	4	145	5	(7)	147
Total net risk management assets	4	751	5	23	783

As at Dec. 31, 2015

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	31	-	57	88
Long-term	-	551	-	(27)	524
Net commodity risk management assets	-	582	-	30	612
Other					
Current	(7)	20	-	(3)	10
Long-term	-	207	5	(8)	204
Net other risk management assets (liabilities)	(7)	227	5	(11)	214
Total net risk management assets (liabilities)	(7)	809	5	19	826

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. Commodity Price Risk

Value at Risk ("VaR") is the most commonly used metric employed to track and manage the market risk associated with commodity and other derivatives. 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.

a. 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.

VaR at March 31, 2016 associated with the Corporation's proprietary trading activities was \$3 million (Dec. 31, 2015 - \$5 million).

b. Commodity Price Risk - Generation

Various commodity contracts and other financial instruments are used to manage the commodity price risk associated with the Corporation's electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. VaR at March 31, 2016 associated with the Corporation's commodity derivative instruments used in these hedging activities was \$23 million (Dec. 31, 2015 - \$24 million). VaR at March 31, 2016 associated with positions and economic hedges that do not meet hedge accounting requirements was \$2 million (Dec. 31, 2015 - \$1 million).

II. Currency Rate Risk

The Corporation has exposure to various currencies, such as the euro, the US dollar, the Japanese yen, and the Australian dollar, 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)(c) of the Corporation's most recent annual consolidated financial statements.

III. 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 fulfill their obligations under the related contracts prior to entering into such contracts. TransAlta is exposed to minimal credit risk for Alberta Coal PPAs as receivables are substantially all secured by letters of credit.

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. In certain cases, the Corporation will require security instruments such as parental guarantees, letters of credit, cash collateral or third party credit insurance to reduce overall credit risk. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at March 31, 2016:

	Investment grade <i>(Per cent)</i>	Non-investment grade <i>(Per cent)</i>	Total <i>(Per cent)</i>	Total amount
Trade and other receivables ⁽¹⁾	89	11	100	457
Long-term finance lease receivables ⁽²⁾	40	60	100	731
Risk management assets ⁽¹⁾	100	-	100	1,021
Total				2,209

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

(2) The Corporation has one non-investment grade customer whose outstanding balances accounted for \$415 million (Dec. 31, 2015 - \$446 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, and 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, 2016 was \$45 million (Dec. 31, 2015 - \$44 million).

IV. 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. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. As at March 31, 2016, TransAlta maintains investment grade ratings from three credit rating agencies. For further details refer to Note 14(B) of the Corporation's most recent annual consolidated financial statements.

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

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Accounts payable and accrued liabilities	336	-	-	-	-	-	336
Long-term debt ⁽¹⁾	87	566	899	446	446	1,521	3,965
Commodity risk management (assets) liabilities	(61)	(78)	(48)	(62)	(67)	(320)	(636)
Other risk management (assets) liabilities	(8)	(87)	(55)	2	1	-	(147)
Finance lease obligations	12	14	13	9	7	24	79
Interest on long-term debt and finance lease obligations ⁽²⁾	161	200	158	129	102	758	1,508
Dividends payable	26	-	-	-	-	-	26
Total	553	615	967	524	489	1,983	5,131

(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, 2016, the Corporation had posted collateral of \$194 million (Dec. 31, 2015 - \$220 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 \$56 million (Dec. 31, 2015 - \$44 million) of collateral to its counterparties.

9. 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, 2015	95	2,811	611	2,455	604	351	246	7,173
Additions	1	-	-	-	-	90	(6)	85
Additions - finance lease	-	-	-	-	1	-	-	1
Disposals	(1)	-	-	-	-	-	-	(1)
Depreciation	-	(70)	(18)	(32)	(15)	-	(4)	(139)
Revisions and additions to decommissioning and restoration costs	-	(14)	(4)	(3)	2	-	-	(19)
Retirement of assets	-	(4)	-	(1)	-	-	-	(5)
Change in foreign exchange rates	(1)	(24)	(6)	(20)	(4)	(7)	(3)	(65)
Transfers	-	18	1	7	3	(33)	4	-
As at March 31, 2016	94	2,717	584	2,406	591	401	237	7,030

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

10. 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, 2016			Dec. 31, 2015		
	Carrying value	Face value	Interest ⁽¹⁾	Carrying value	Face value	Interest ⁽¹⁾
Credit facilities ⁽²⁾	-	-	-	315	315	3.1%
Debentures	1,045	1,051	6.0%	1,044	1,051	6.0%
Senior notes ⁽³⁾	2,073	2,074	5.0%	2,221	2,221	4.9%
Non-recourse ⁽⁴⁾	754	761	4.5%	766	773	4.5%
Other ⁽⁵⁾	79	79	8.1%	67	67	9.3%
	3,951	3,965		4,413	4,427	
Finance lease obligations	79			82		
	4,030			4,495		
Less: current portion of long-term debt	(87)			(72)		
Less: current portion of finance lease obligations	(16)			(15)		
Total current long-term debt and finance lease obligations	(103)			(87)		
Total credit facilities, long-term debt, and finance lease obligations	3,927			4,408		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.

(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.

(3) US face value at March 31, 2016 - US\$1.6 billion (Dec. 31, 2015 - US\$1.6 billion).

(4) Includes US\$54 million at March 31, 2016 (Dec. 31, 2015 - US\$59 million).

(5) Includes US\$35 million at Dec. 31, 2015 (Dec. 31, 2015 - US\$36 million) of tax equity financing and \$17 million (Dec. 31, 2015 - nil) of overdraft.

During the first quarter, the Corporation paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of \$173 million received from the sale of the economic interest of the Canadian Assets that closed Jan. 6, 2016.

Of the \$2.1 billion (Dec. 31, 2015 - \$2.2 billion) of committed credit facilities, \$1.5 billion (Dec. 31, 2015 - \$1.3 billion) is not drawn. The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the \$1.5 billion available under the credit facilities, TransAlta also has \$30 million of available cash and cash equivalents.

The total outstanding letters of credit as at March 31, 2016 was \$588 million (Dec. 31, 2015 - \$575 million) with no (Dec. 31, 2015 - 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, 2016, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of \$229 million (Dec. 31, 2015 - \$230 million) issued by the Corporation's Canadian Hydro Developers, Inc. ("CHD") subsidiary 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 \$531 million (Dec. 31, 2015 - \$536 million) is secured by certain renewable generation facilities and subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by the facilities' operations. Certain bonds are 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 \$780 million at March 31, 2016 (Dec. 31, 2015 - \$798 million).

11. 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			
	2016		2015	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	284.0	3,077	275.0	3,001
Issued under the dividend reinvestment and optional common share purchase plan	3.9	18	2.0	20
	287.9	3,095	277.0	3,021
Amounts receivable under Employee Share Purchase Plan	-	(2)	-	(2)
Issued and outstanding, end of period	287.9	3,093	277.0	3,019

B. Dividends and Shareholder Rights Plan

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from \$0.72 annually to \$0.16 annually and the suspension of the Premium DividendTM, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP") effective immediately. These actions were taken as part of a plan to maximize the Corporation's long-term financial flexibility, as well as to stop shareholder dilution relating to the DRIP.

On Feb. 16, 2016, the Corporation declared a quarterly dividend of \$0.04 per common share, payable on April 1, 2016.

On April 21, 2016, the Corporation declared a quarterly dividend of \$0.04 per common share, payable on July 1, 2016.

On April 22, 2016, the Shareholder Rights Plan discussed in Note 22 of the Corporation's most recent annual consolidated financial statements was renewed for a new period of approximately three years.

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 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.

12. Preferred Shares

A. Issued and Outstanding

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at March 31, 2016.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board. The annualized dividend rate for the Series B Shares for the 3-month floating rate period from and including March 31, 2016 to but excluding June 30, 2016 is 2.492 per cent and will reset every quarter.

Additionally, at March 31, 2016, the Corporation also had 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G Cumulative Redeemable Rate Reset 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	3 months ended March 31	
		2016	2015
		Total	Total
A	0.2875	4	4
C	0.2875	3	3
E	0.3125	3	3
G	0.33125	2	2
Total for the period		12	12

On April 21, 2016, the Corporation declared a quarterly dividend of \$0.16931 per share on the Series A preferred shares, \$0.15490 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 June 30, 2016.

13. 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.

14. Segment Disclosures

A. Reported Statement of Earnings (Loss)

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	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 gain									(6)
Earnings before income taxes									53

3 months ended March 31, 2015 (Restated - See Note 2)	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	246	51	141	26	73	25	31	-	593
Fuel and purchased power	113	47	67	5	4	1	-	-	237
Gross margin	133	4	74	21	69	24	31	-	356
Operations, maintenance, and administration	49	12	18	6	12	11	8	18	134
Depreciation and amortization	57	15	23	4	22	6	-	6	133
Restructuring provision	7	-	-	-	-	-	-	-	7
Taxes, other than income taxes	3	1	1	-	2	-	-	-	7
Operating income (loss)	17	(24)	32	11	33	7	23	(24)	75
Finance lease income	-	-	1	12	-	-	-	-	13
Net interest expense									(60)
Foreign exchange gain									1
Earnings before income taxes									29

During the three months ended March 31, 2016, coal inventory at the Corporation's Centralia plant was written down by \$6 million (2015 - \$10 million) to its net realizable value. The writedown is included in fuel and purchased power of the U.S. Coal Segment.

Included in revenues of the Wind and Solar Segment for the three months ended March 31, 2016 are \$7 million (2015 - \$6 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

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	2016	2015
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings (Loss)	122	133
Depreciation included in fuel and purchased power	14	14
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	136	147

Supplemental Information

		March 31, 2016	Dec. 31, 2015
Closing market price (TSX) (\$)		6.04	4.91
Price range for the last 12 months (TSX) (\$)	High	12.34	12.34
	Low	3.76	4.13
Adjusted net debt to invested capital ⁽¹⁾ (%)		51.6	54.6
Adjusted net debt to invested capital excluding non-recourse debt ⁽¹⁾ (%)		46.9	50.2
Adjusted net debt to comparable EBITDA ^(1, 2) (times)		4.6	5.0
Return on equity attributable to common shareholders ⁽²⁾ (%)		3.7	(1.2)
Comparable return on equity attributable to common shareholders ^(1, 2) (%)		(2.8)	(2.3)
Return on capital employed ⁽²⁾ (%)		5.2	4.6
Comparable return on capital employed ^(1, 2) (%)		2.8	3.0
Earnings coverage ⁽²⁾ (times)		1.6	1.5
Dividend payout ratio based on comparable funds from operations ^(1, 2, 3) (%)		23.5	28.3
Dividend coverage ^(2, 3) (times)		4.5	3.6
Dividend yield ^(2, 3)		11.9	14.7
Adjusted comparable FFO to adjusted net debt ⁽²⁾ (%)		16.2	15.2
Comparable FFO before interest to adjusted interest coverage ⁽²⁾ (times)		3.7	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 or earnings on a comparable basis / equity attributable to common shareholders excluding AOCI

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

(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 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.

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

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

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

Adjusted comparable funds from operations to adjusted net debt = comparable funds from operations - 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

Comparable funds from operations before interest to adjusted interest coverage = comparable funds from operations + 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.

Specified Gas Emitters Regulation (SGER) - Rules under the Alberta Climate Change and Emissions Management Act which lays out emission intensity reduction targets for specified entities and guidelines for achieving compliance.

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



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