TransAlta™

TRANSALTA CORPORATION
THIRD QUARTER REPORT FOR 2015

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2015 and 2014, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2014 Annual Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", and "TransAlta" refers to TransAlta Corporation and its subsidiaries. The condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") *IAS 34 Interim Financial Reporting*. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 29, 2015. 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.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segments. We have seven business segments. See the Discussion of Segmented Comparable Results section of this MD&A for information regarding the first quarter 2015 change in our segments. In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Condensed Consolidated Statements of Earnings and Condensed Consolidated Statements of Financial Position items. While individual line items in the Condensed Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of these items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive Income ("AOCI") in the equity section of the Condensed Consolidated Statements of Financial Position.

NON-IFRS MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of these 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 Funds from Operations and Free Cash Flow and Earnings and Other Measures on a Comparable Basis sections of this MD&A for additional information, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

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. 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", "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 or the Sundance 7 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; 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 2015 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 2015); 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 impact of a possible downgrade by Moody's Investor Services Inc. ("Moody's"); 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; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws, including the anticipated financial impact of increased Specified Gas Emitters Regulation ("SGER") obligations in Alberta, and the value of offsets generated by our wind facilities in the province; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets 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 relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of TransAlta Renewables; expectations in respect of the Keephills 1 Force Majeure event, including the impact of the claim, penalties, and insurance coverage; and expectations of reversal of coal inventory writedown.

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 domestic 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 rating; 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 Risk Management section of our 2014 Annual MD&A and under the heading “Risk Factors” in our 2015 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 Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Revenues	**641**	639	**1,672**	1,905
Comparable EBITDA[1]	**219**	212	**677**	735
Net earnings (loss) attributable to common shareholders	**154**	(6)	**30**	(7)
Comparable net earnings (loss) attributable to common shareholders[1]	**(33)**	(13)	**(51)**	22
Comparable funds from operations[1]	**126**	145	**497**	537
Cash flow from operating activities	**200**	216	**314**	546
Comparable free cash flow[1]	**8**	34	**141**	192
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.55**	(0.03)	**0.11**	(0.03)
Comparable net earnings (loss) per share[1]	**(0.12)**	(0.05)	**(0.18)**	0.08
Comparable funds from operations per share[1]	**0.45**	0.53	**1.78**	1.97
Comparable free cash flow per share[1]	**0.03**	0.12	**0.51**	0.71
Dividends paid per common share	**0.18**	0.18	**0.54**	0.65

As at	**Sept. 30, 2015**	Dec. 31, 2014
Total assets	**10,756**	9,833
Total credit facilities, long-term debt, and finance lease obligations[2], net of cash	**4,413**	4,013
Total long-term liabilities	**5,766**	4,504

Financial Highlights

- Comparable EBITDA for the three months ended Sept. 30, 2015 increased by $7 million to $219 million compared to the same period in 2014. Prices in Alberta have decreased from $64 per megawatt hour (“MWh”) in the third quarter of 2014 to $26 per MWh in the third quarter of 2015 but our high level of contracts and hedges mostly mitigated the impact of low price. Continued improvement in our mining operations to reduce fuel costs as well as a return to normal level in margin by Energy Marketing contributed to our good performance in the quarter. Our wind and hydro businesses in Alberta were impacted by lower price. Year-to-date, comparable EBITDA decreased $58 million to $677 million compared to the same period in 2014. A significant part of the decrease is attributable to unfavourable Energy Marketing results during the second quarter of 2015, lower availability in Canadian Coal during the first half of the year, and lower prices in Alberta and the Pacific Northwest. Last year, Energy Marketing’s performance was positively impacted by higher volatility due to extraordinary conditions in the first quarter.

(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 Funds from Operations and Free Cash Flow 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) Includes current portion.

- Comparable FFO decreased by $19 million to $126 million for the three months ended Sept. 30, 2015 despite higher EBITDA, as non-realized mark-to-market losses included in EBITDA in the second quarter have reversed in the third quarter. On a year-to-date basis, comparable FFO decreased by $40 million to $497 million. The change in FFO was mainly due to the decrease in EBITDA. Lower interest expense, lower cash taxes, and an increase in realized foreign exchange gains offset some of the shortfall in EBITDA.
- During the quarter, comparable net loss attributable to common shareholders was $33 million ($0.12 net loss per share), down from a comparable net loss of $13 million ($0.05 net loss per share) in the same period in 2014. The decrease was primarily due to an increase in depreciation and amortization resulting from the strengthening US dollar, an increase in asset retirements, and an increase in income tax expense due to an increase in taxable temporary differences. Year-to-date, comparable net loss attributable to common shareholders was $51 million ($0.18 net loss per share), down from comparable net earnings of $22 million ($0.08 net earnings per share) in the same period in 2014. The decrease was primarily a result of lower comparable EBITDA.
- Reported net earnings attributable to common shareholders was $154 million for the quarter ($0.55 net earnings per share) compared to a net loss of $6 million ($0.03 net loss per share) for the same period in 2014. On a year-to-date basis, reported net earnings attributable to common shareholders was $30 million ($0.11 net earnings per share) compared to a net loss of $7 million ($0.03 net loss per share) for the same period in 2014. For each period, the differences between comparable and reported net earnings are mainly due to the gain on the Poplar Creek contract restructuring ($193 million[1]), the provision relating to the proposed settlement with the Market Surveillance Administrator (the "MSA") ($55 million[1]), and restructuring costs ($8 million[1] for the quarter and $13 million[1] for the year-to-date). Changes in the fair value of de-designated and economic hedges at U.S. Coal also impacted our net earnings negatively since the beginning of the year ($31 million[1,2]). Deferred income tax expense during the first half of 2015 was also impacted by the increase in the Alberta corporate tax rate in June 2015 and by an internal reorganization associated with the sale of an economic interest in our Australian business to TransAlta Renewables.
- During the nine month period in 2015, credit facilities, long-term debt, and finance lease obligations have increased by $400 million primarily as a result of the stronger US dollar ($312 million) and the acquisition during the quarter of operating solar facilities ($106 million).

Strategic Initiative Highlights

During the quarter we continued to strengthen our financial condition, improve our operating performance, and make significant progress to grow our portfolio of highly contracted assets through initiatives such as:

- We restructured our contractual arrangements at the Poplar Creek facility, to extend the contracted cash flows attributable to Poplar Creek to 2030, from the prior 2023 expiry, and we also acquired two wind facilities, representing 65 megawatts ("MW") of capacity. As part of the restructuring, our customer assumed operational control of the facility and acquired our steam generators and the rights to the output of the gas generators. The transaction closed on Sept. 1, 2015 and we have recognized a gain of $263 million on the transaction:
    - recognition of a finance lease of $372 million less derecognition of Poplar Creek net assets, including exchanged working capital, at a carrying amount of $247 million; and
    - the acquisition of two wind farms for $138 million.

  Over the last three years, we have nearly doubled the weighted average remaining contractual life of our gas fleet from 6 years to 12 years.

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(1) Net of related income tax expense.

(2) Hedge accounting could not be applied to certain contracts, and accordingly, the mark-to-market on these contracts impacted reporting earnings. The impacts of these mark-to-market fluctuations have been removed from revenues to arrive at comparable results, which reflect the economic nature of these contracts.

- We acquired 71 MW of fully contracted renewable generation assets for cash consideration of US$76 million together with the assumption of certain tax equity and US$42 million of non-recourse project debt. The assets include our first solar facilities, representing 21 MW of capacity in Massachusetts, and one 50 MW wind farm in Minnesota. The acquisition of the solar facilities was completed on Sept. 1, 2015, while the acquisitions of the wind farm closed on Oct. 1, 2015.
- We reached an agreement with the MSA to settle all outstanding proceedings before the Alberta Utilities Commission (the "AUC") for a total amount of $56 million, which was approved by the AUC on Oct. 29, 2015. Of this amount, $31 million will be paid 30 days after the approval date and $25 million will be paid one year after this first payment.
- Reduced our overhead by $25 million annually by eliminating 239 positions. Together with overhead reductions in Canadian Coal announced earlier this year, our efficiency and productivity initiatives will contribute $47 million in cost savings annually.
- Raised $442 million in long-term project financing. The financing closed on Oct. 1, 2015. Proceeds will be used to reduce the draw down on our credit facilities.

Earlier this year, we also completed the following transactions:

- TransAlta Renewables acquired an economic interest based on the cash flows of our Australian assets (the "Transaction"). We received net cash proceeds of $211 million as well as approximately $1,067 million as consideration for the interest through a combination of Common Shares and Class B Shares in TransAlta Renewables, increasing our ownership from 70 per cent to 76 per cent. Cash proceeds of the Transaction were used to reduce borrowings on our credit facilities.
- TAMA Power, our joint venture with Berkshire Hathaway Energy Company, received approval from the AUC to construct Sundance 7, an 856 MW high efficiency natural gas-fired power plant in Alberta. Construction of Sundance 7 will not commence until we have contracted a significant portion of the plant capacity.
- Successfully completed construction of the natural gas pipeline to our Solomon power station. Since the beginning of the year, the pipeline has contributed $6 million to our EBITDA and FFO.
- Commenced construction of the South Hedland Power Project. The civil construction phase is progressing and manufacturing and factory acceptance testing of primary electrical equipment was completed. Major equipment is scheduled to be delivered to the site starting in the fourth quarter.
- Entered into a new 15-year 72 MW power supply contract for our Windsor facility with Ontario's Independent Electricity System Operator ("IESO"). The new contract will take effect in December 2016.
- Reduced our workforce at our Canadian Coal operations and optimized mine operations to provide sustained savings of $22 million annually.

Operational Results

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Availability (%)[1]	**91.2**	92.0	**87.3**	88.6
Adjusted availability (%)[2]	**91.2**	92.0	**87.8**	89.6
Production (GWh)[1,3]	**10,839**	11,445	**29,559**	32,795
Comparable EBITDA:				
Canadian Coal	**101**	92	**267**	270
U.S. Coal	**10**	13	**44**	46
Gas	**80**	77	**240**	232
Wind[4]	**23**	27	**111**	123
Hydro	**15**	27	**54**	67
Energy Marketing	**6**	(4)	**11**	49
Corporate	**(16)**	(20)	**(50)**	(52)
Total comparable EBITDA	**219**	212	**677**	735

- Canadian Coal: Comparable EBITDA in the third quarter was $101 million and $267 million on a year-to-date basis, compared to $92 million and $270 million, respectively, for the same periods in 2014. Our high level of contracts and hedges in Canadian Coal mostly offset the impact of lower price in Alberta compared to last year. Canadian Coal also experienced higher derates during the quarter due to the impact of hot weather on cooling ponds. In addition, during the quarter we completed planned outages at Sundance 5 and at Keephills 3. The reductions in operating expenses at our power plants and at our Highvale mine and mark-to-market gains on certain forward financial contracts that do not qualify for hedge accounting fully offset the negative impact of lower availability and lower price on our comparable EBITDA.
- U.S. Coal: Comparable EBITDA was $10 million in the quarter compared to $13 million for the same period in 2014 and $44 million on a year-to-date basis compared to $46 million in 2014. Quarterly results were negatively impacted by coal inventory writedowns and reduced generation resulting from low power prices, which were partially offset by mark-to-market gains on financial contracts put in place to hedge our future generation and the stronger US dollar. On a year-to-date basis, limited merchant sales and mark-to-market losses were partially offset by the appreciation of the US dollar. We anticipate the effects of coal inventory writedowns to reverse during the fourth quarter as coal is used for production.
- Gas: Comparable EBITDA in the third quarter was $80 million and $240 million on a year-to-date basis, compared to $77 million and $232 million, respectively, for the same periods in 2014. The increase in comparable EBITDA was a result of additional revenues from the Australian natural gas pipeline and the positive impact of the strengthening of the US dollar on a certain contract in Australia.
- Wind: Comparable EBITDA for the three and nine month periods decreased by $4 million and $12 million, respectively, to $23 million and $111 million compared to the same periods in 2014, primarily as a result of lower wind volumes in Eastern Canada and lower power prices in Alberta.

(1) Availability and production includes all generating assets (generation operations and finance leases that we operate). 2014 availability also includes equity investments, which were sold in May 2014.

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

(3) 2014 production includes 314 GWh from CE Generation LLC and Wailuku Holding Company, LLC, both of which were sold in May 2014. Refer to the Significant 2014 Events and Subsequent Events section of our 2014 Annual MD&A for further discussion.

(4) Wind Segment includes results of solar facilities acquired during the quarter. Refer to the Significant and Subsequent Events section of this MD&A for further details.

- Hydro: Comparable EBITDA was $15 million in the quarter compared to $27 million for the same period in 2014 and $54 million on a year-to-date basis compared to $67 million in 2014. The decrease was a result of lower prices and a decrease in price volatility in Alberta during the third quarter, which limited our ability to take advantage of our flexibility to produce electricity in higher priced hours.
- Energy Marketing: Energy Marketing generated comparable EBITDA of $6 million in the quarter compared to an EBITDA loss of $4 million for the same period in 2014. This represented a return to normal gross margin for Energy Marketing. On a year-to-date basis, comparable EBITDA was down $38 million to $11 million. The decrease is attributable to extraordinary market conditions in the first quarter of last year that resulted in substantial customer margins and volatile market conditions in the Alberta and Pacific Northwest regions in the second quarter of this year that negatively affected our Energy Marketing results.
- Corporate: Our Corporate Segment incurred lower costs for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 as a result of legal costs incurred relating to the MSA proceeding in front of the AUC in 2014.

AVAILABILITY & PRODUCTION

Availability for the three months ended Sept. 30, 2015 was slightly below the same period in 2014, primarily due to higher derates at Canadian Coal due to hot weather impacting cooling ponds.

Availability for the nine months ended Sept. 30, 2015 is also slightly below last year's level, primarily due to a two-month Force Majeure outage at our Keephills 1 facility caused by a damaged superheater. The unit returned to service on May 17, 2015. Availability during the period was also impacted by higher derates at Canadian Coal, the extension of the planned outage at Sundance 3 to allow for more work to be completed, and the completion of a planned outage at Keephills 3 in August. In 2014, we had one planned major maintenance outage at Genesee 3 in the fourth quarter. As at Sept. 30, 2015, our planned major maintenance activities in coal are complete for the year.

Production for the three and nine months ended Sept. 30, 2015 decreased by 606 gigawatt hours ("GWh") and 3,236 GWh, respectively, compared to the same periods in 2014 due to lower availability from Canadian Coal in the first half of the year and increased economic dispatching at U.S. Coal resulting from lower prices in the Pacific Northwest this year. These lower prices provided us the opportunity to shut down or dial down our generation and supply our contractual obligation by buying cheaper power in the market.

COMPARABLE FUNDS FROM OPERATIONS AND COMPARABLE FREE CASH FLOW

Comparable funds from operations and comparable free cash flow 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 Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Cash flow from operating activities	**200**	216	**314**	546
Change in non-cash operating working capital balances	**(81)**	(76)	**166**	(50)
Cash flow from operations before changes in working capital	**119**	140	**480**	496
Adjustments:				
Payment of restructuring costs	**1**	-	**8**	-
Impacts associated with California claim	**-**	-	**-**	33
Decrease in finance lease receivable	**6**	1	**8**	2
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	**-**	4	**1**	6
Comparable FFO	**126**	145	**497**	537
Deduct:				
Sustaining capital	**(79)**	(84)	**(253)**	(255)
Insurance recoveries of sustaining capital expenditures related to Alberta flood of 2013	**2**	1	**2**	1
Dividends paid on preferred shares	**(12)**	(9)	**(35)**	(28)
Distributions paid to subsidiaries' non-controlling interests	**(29)**	(19)	**(70)**	(63)
Comparable FCF	**8**	34	**141**	192
Weighted average number of common shares outstanding in the period	**281**	273	**279**	272
Comparable FFO per share	**0.45**	0.53	**1.78**	1.97
Comparable FCF per share	**0.03**	0.12	**0.51**	0.71

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Comparable EBITDA	**219**	212	**677**	735
Unrealized (gains) losses from risk management activities	**(29)**	6	**7**	16
Interest expense	**(58)**	(59)	**(167)**	(178)
Provisions	**1**	(4)	**(3)**	-
Current income tax expense	**(1)**	(7)	**(12)**	(24)
Realized foreign exchange gain (loss)	**3**	(4)	**16**	(3)
Decommissioning and restoration costs settled	**(7)**	(4)	**(20)**	(11)
Other non-cash items	**(2)**	5	**(1)**	2
Comparable FFO	**126**	145	**497**	537

Comparable FFO decreased by $19 million to $126 million for the three months ended Sept. 30, 2015 compared to the same period in 2014, due to mark-to-market gains on financial contracts put in place to hedge our future generation, as mark-to-market losses included in comparable EBITDA in the second quarter have reversed in the third quarter. A decrease in cash taxes and an increase in realized foreign exchange gain offset a portion of these gains.

For the nine months ended Sept. 30, 2015, comparable FFO decreased by $40 million to $497 million compared to the same period in 2014 mainly due to the reduction in comparable EBITDA. A decrease in interest expense and cash taxes, and an increase in realized foreign exchange gain offset some of the shortfall in comparable EBITDA.

Comparable FCF for the three months ended Sept. 30, 2015 was $8 million, compared to $34 million for the same period in 2014. In addition to the decrease in comparable FFO, comparable FCF decreased as a result of an increase in dividends paid on preferred shares and an increase in distributions paid to subsidiaries' non-controlling interests, which was partially offset by a decrease in sustaining capital expenditures.

On a year-to-date basis, the decrease in comparable FCF was mainly due to the reduction in comparable FFO and an increase in dividends paid on preferred shares and an increase in distributions paid to subsidiaries' non-controlling interests.

FINANCIAL POSITION

We seek to maintain financial flexibility by using multiple sources of capital to finance our business plans, while maintaining a sufficient level of available liquidity to support contracting and trading activities. We are focused on strengthening our financial position and cash flow coverage ratios to support stable investment grade credit ratings.

We have developed our own definitions of ratios and targets to manage our capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

Comparable Funds From Operations before Interest to Adjusted Interest Coverage

As at	**Sept. 30, 2015**	Dec. 31, 2014
Comparable FFO(1)	**722**	762
Add: Interest on debt net of interest income and capitalized interest(1)	**224**	236
Comparable FFO before interest(1)	**946**	998
Interest on debt net of interest income(1)	**233**	239
Add: 50 per cent of dividends paid on preferred shares(1)	**24**	21
Adjusted interest(1)	**257**	260
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 is comparable to last year. We are aiming to meet our target range by 2016.

(1) Last 12 months.

Adjusted Comparable Funds From Operations to Adjusted Net Debt

As at	Sept. 30, 2015	Dec. 31, 2014
Comparable FFO(1)	**722**	762
Less: 50 per cent of dividends paid on preferred shares(1)	**(24)**	(21)
Adjusted comparable FFO(1)	**698**	741
Period-end long-term debt, including finance lease obligations	**4,450**	4,056
Add: 50 per cent of issued preferred shares	**471**	471
Less: Cash and cash equivalents (excluding restricted cash)	**(37)**	(43)
Fair value (asset) of hedging instruments on debt(2)	**(171)**	(96)
Adjusted net debt	**4,713**	4,388
Adjusted comparable FFO to adjusted net debt (%)	**14.8**	16.9

Our target for Adjusted Comparable FFO to Adjusted Net Debt is 20 to 25 per cent. We are aiming to meet our target range in 2016. The reduction in the ratio during the year-to-date is due to lower comparable FFO and the strengthening of the US dollar impacts on our US-denominated debt. Our US-denominated debt is fully hedged by US-denominated assets, some of which revalue outside of net debt adjustments. As at Sept. 30, 2015, net debt is also impacted by the addition of debt resulting from the acquisition of the solar facilities in Massachusetts ($106 million) and by variations in working capital ($164 million), which offsets the debt reduction of $211 million achieved through the funds raised by the Transaction with TransAlta Renewables.

Adjusted Net Debt to Comparable EBITDA

As at	Sept. 30, 2015	Dec. 31, 2014
Period-end long-term debt, including finance lease obligations	**4,450**	4,056
Less: cash and cash equivalents	**(37)**	(43)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value (asset) of hedging instruments on debt(2)	**(171)**	(96)
Adjusted net debt	**4,713**	4,388
Comparable EBITDA(1)	**978**	1,036
Adjusted net debt to comparable EBITDA (times)	**4.8**	4.2

Our target for Adjusted Net Debt to Comparable EBITDA is three to four times. During the year-to-date, our ratio deteriorated compared to Dec. 31, 2014, mainly as a result of lower comparable EBITDA during the period and strengthening of the US dollar as described in the Adjusted Comparable FFO to Adjusted Net Debt section above. We are aiming to meet our target range in 2016.

SIGNIFICANT AND SUBSEQUENT EVENTS

Sale of Economic Interest to TransAlta Renewables Inc.

On May 7, 2015, we completed the sale of an economic interest based on the cash flows of our Australian assets to TransAlta Renewables. The Australian assets consist of 575 MW of power generation from six operating assets and the South Hedland project currently under construction, as well as the recently commissioned 270 kilometre gas pipeline. TransAlta Renewables' investment consists of the acquisition of securities that, in aggregate, provide an economic interest based on cash flows of the Australian assets for a total consideration of $1.78 billion.

(1) Last 12 months.

(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2015 and Dec. 31, 2014.

With the closing of the Transaction, TransAlta Renewables paid the Corporation $217 million as well as approximately $1,067 million through a combination of Common Shares and Class B Shares in TransAlta Renewables, increasing our ownership from 70 per cent to 76 per cent. TransAlta Renewables has also committed to funding the remaining costs to construct the South Hedland project, estimated at $491 million.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 Common Shares at a price of $12.65 per share. The offering closed in two parts on April 15 and 23, 2015. TransAlta Renewables shareholder approval was received on May 7, 2015.

Poplar Creek

On Sept. 1, 2015, we closed the previously announced restructuring of the current arrangement for power generation services with Suncor Energy ("Suncor") at Suncor's oil sands base site near Fort McMurray and the acquisition of Suncor's interest in two wind farms located in Alberta and Ontario.

Our Poplar Creek co-generation facility, which has a maximum capability of 376 MW, had been built and contracted to provide steam and electricity to Suncor until 2023. Under the terms of the new arrangement, Suncor acquired two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the co-generation facility, including responsibility for all capital costs, and the right to use the full 244 MW capacity of TransAlta's gas generators until Dec. 31, 2030. We will provide Suncor with centralized monitoring, diagnostics and technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek co-generation facility will transfer to Suncor in 2030.

As part of the arrangement, we acquired Suncor's interest in the 20 MW Kent Breeze wind facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills wind facility located in Alberta. The Kent Breeze facility has a 20-year contract with the Ontario IESO.

The restructuring creates value by increasing the duration of the contract until 2030 and reduces our exposure to Alberta's merchant power market. It also adds two high quality wind farms to our portfolio and creates potential for future drop-down into TransAlta Renewables of the fully contracted gas generating assets and the two wind farms. We have recognized a gain of $263 million on the transaction:

- recognition of a finance lease of $372 million less derecognition of Poplar Creek net assets, including exchanged working capital, at a carrying amount of $247 million;
- supplemented by the acquisition of two wind farms for $138 million.

Over the last three years, we have nearly doubled the weighted average remaining contractual life of our gas fleet from 6 years to 12 years.

U.S. Wind and Solar Acquisition

On July 26, 2015, we agreed to acquire 71 MW of fully contracted renewable generation assets for cash consideration of US$76 million together with the assumption of certain tax equity and US$42 million of non-recourse debt. The assets acquired include 21 MW of solar projects located in Massachusetts and a 50 MW Lakeswind wind project located in Minnesota. The assets are contracted under long-term power purchase agreements ranging from 20 to 30 years. The purchase of the solar projects in Massachusetts closed on Sept. 1, 2015 and the purchase of the Lakeswind wind project in Minnesota was completed on Oct. 1, 2015. Please refer to *Note 3* of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2015 and 2014 for additional information.

The acquisition marks our first solar facilities and aligns with our strategy of growing our renewables platform, diversifying our portfolio, and increasing the pipeline of assets for potential future drop-down into TransAlta Renewables. The acquisition adds geographic, technological and counterparty diversification, and establishes a broader platform in the U.S. for future growth in renewables.

The solar projects, consisting of four ground mounted facilities and four roof-top facilities, are all contracted on a long-term basis and are qualified under phase one of the Massachusetts Solar Renewable Energy Credit (SREC-I) program, established to encourage investment in distributed solar generation. The wind facility has been operational since March 2014 and is contracted under three long-term power purchase agreements until 2034 with high quality counterparties.

Sundance 7

On June 9, 2015, TAMA Power received approval from the AUC to construct and operate an 856 MW combined-cycle natural gas-fired power plant in Alberta.

The Sundance 7 project has received all regulatory approvals after receiving the Environmental Protection Enhancement Act approval from Alberta Environment and Parks on Oct. 1, 2015. Construction of Sundance 7 will not commence until we have contracted a significant portion of the plant capacity.

South Hedland Power Project

Construction of the South Hedland Project commenced in January 2015. The civil construction phase is progressing with all major foundation footings complete, with the exception of the steam turbine. Manufacturing and factory acceptance testing of primary electrical equipment was completed. We expect to start receiving equipment on site during the fourth quarter.

Washington State Memorandum of Agreement

On July 30, 2015 we announced that we are moving ahead with plans to invest US$55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington state.

The US$55 million community investment is part of the TransAlta Energy Transition Bill, passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington state, closing the Centralia facility's two units, one in 2020 and the other in 2025.

Although we did not secure additional long-term contracts totaling 500 MW as planned in the original agreement as a condition of the investment, we are following through on our funding pledge and securing mutual benefits agreed with the state for orderly transition.

Keephills 1 Force Majeure

On March 17, 2015, an unplanned outage began at our 395 MW Keephills 1 facility due to a damaged superheater. The unit returned to service on May 17, 2015.

Following the establishment of the plan to return the unit to service and the review of the causes of the outage, we gave notice under the Power Purchase Arrangement ("PPA") to the PPA buyer and the Balancing Pool of a "High Impact Low Probability" Force Majeure event. In the event of a Force Majeure event, we are entitled to continue to receive our PPA capacity payment and are protected under the terms of the PPA from having to pay availability penalties. We also anticipate the costs incurred as a result of the event will be covered by insurance. Consequently, the outage is not anticipated to have a material financial impact.

Australian Natural Gas Pipeline

On March 19, 2015, we announced the completion of the Fortescue River Gas Pipeline in Western Australia. The project, our first pipeline, was completed within a nine month timeframe and for an estimated total cost of AUD$183 million. We hold a 43 per cent interest in the pipeline. The pipeline delivers gas to our Solomon power station which services Fortescue Metals Group's mining operations at the Solomon Hub.

Windsor Recontracting

During the first quarter of 2015, we executed a new 15-year power supply contract with Ontario's IESO for our Windsor facility, which will be effective Dec. 1, 2016. The contract is similar to the contract signed in 2013 for our Ottawa facility. Under the new contract, the plant will become dispatchable for up to 72 MW of capacity. The new contract provides long-term stable earnings for this facility.

Senior Leadership Team Appointment

On Sept. 22, 2015, Jennifer Pierce was named Senior Vice-President, Marketing and Trading following the departure of Rob Schaefer. Jennifer Pierce was most recently our Vice-President, Commercial Management.

Financing Activities

On Jan.15, 2015, our US$500 million 4.75 per cent senior notes matured and were paid out using existing liquidity. On Feb. 11, 2015, we refinanced maturing debt at our Pingston hydroelectric generating facility in British Columbia. Our share of gross proceeds was $45 million. The bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent. Excess proceeds, net of transaction costs, were used for general corporate purposes and to repay corporate debt.

On Oct. 1, 2015, Melancthon Wolfe Wind LP (the "Issuer"), a subsidiary of TransAlta Renewables, closed a $442 million bond offering, which is secured by a first ranking charge over all assets of the Issuer. The bonds are amortizing and bear interest at a rate of 3.834 per cent, payable semi-annually and mature on Dec. 31, 2028. Net proceeds of the financing were used to reduce our balance on the credit facility.

Efficiency and Productivity Initiatives

On Sept. 29, 2015, we announced the elimination of 239 positions to reduce our overhead. The initiative is expected to result in annual cost savings of approximately $25 million.

Earlier this year, we improved productivity at our Canadian Coal power generation and mining operations. These initiatives are expected to generate annual savings of approximately $22 million.

Settlement with the MSA

On Sept. 30, 2015, TransAlta and the MSA reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which is in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the agreement, we will pay a total amount of $56 million including approximately $27 million as a repayment of economic benefit, approximately $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million will be paid 30 days after the approval date, and the $25 million administrative penalty will be paid one year after this first payment. As a result of the approval, we will be discontinuing our appeal of the AUC's decision.

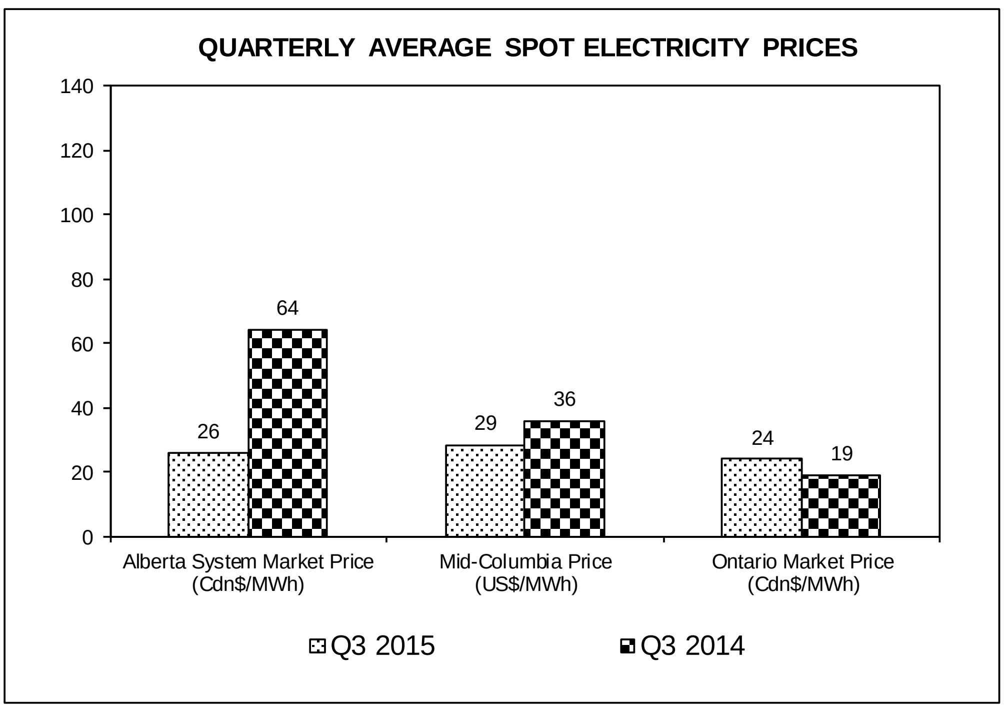
Investment Grade Rating

On Oct. 1, 2015, Moody's placed the rating of our senior unsecured debt under review for possible downgrade. The announcement by Moody's is not anticipated to have a material financial impact on our business as we maintain investment grade ratings with stable outlooks from three credit rating agencies including BBB- (stable outlook) by Standard & Poors, BBB (stable outlook) by DBRS, and BBB- (stable outlook) by Fitch Ratings. We continue to maintain $2.1 billion in committed credit facilities with approximately $0.9 billion in available liquidity as of Sept. 30, 2015 and no material debt maturity until 2017.

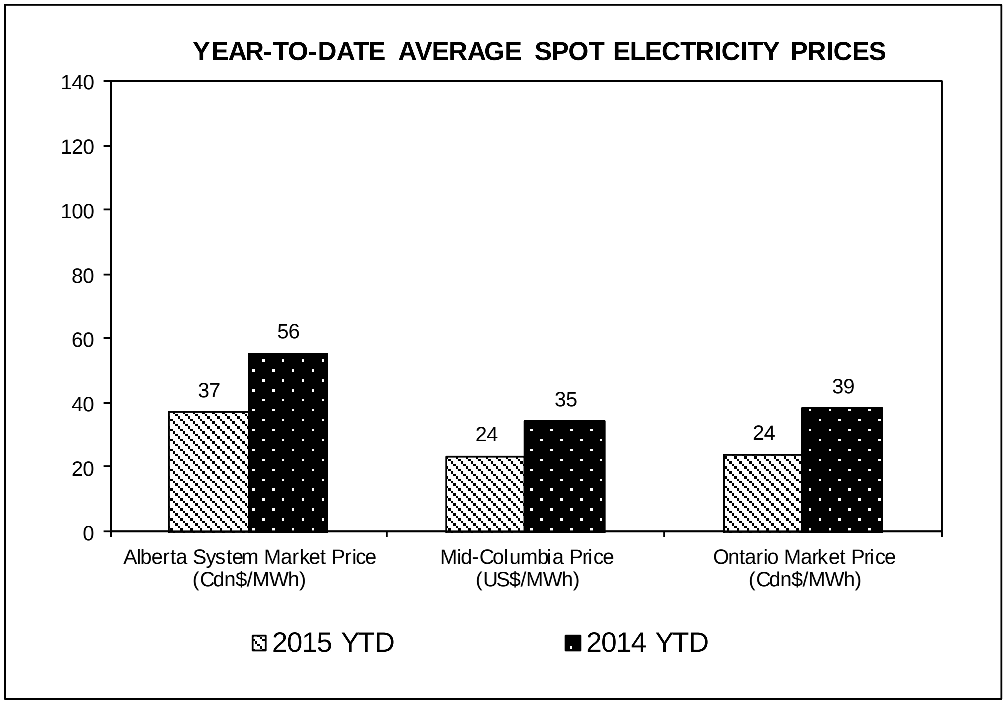
We will continue to execute our plan to strengthen our financial position and remain committed to our financial and operating goals for 2015, including our plan to further reduce debt levels.

ELECTRICITY PRICES

The average spot electricity prices for the three and nine months ended Sept. 30, 2015 and 2014 in the three major markets in which we have merchant capacity are shown in the following graphs:



For the three months ended Sept. 30, 2015, average spot prices in Alberta decreased compared to the same period in 2014 primarily due to increased supply in the province from a new facility that became operational in the first quarter of 2015 and low natural gas prices. In the Pacific Northwest, average spot prices decreased compared to 2014 due to lower natural gas prices, partially offset by higher market heat rates. Average spot prices in Ontario for the three months ended Sept. 30, 2015 increased compared to the same period in 2014 due to increased nuclear outages resulting in lower supply and hot weather in September, which increased demand for the period.



For the nine months ended Sept. 30, 2015, average spot prices decreased in all three markets. Lower natural gas prices have impacted all markets. Increased supply in Alberta led to weak pricing, with the exception of May and June. Low natural gas prices in the Pacific Northwest have lowered power prices, though market heat rates have been stronger than normal due to hydro conditions and reduced coal generation. Ontario prices are lower this year due to weaker prices in the first quarter compared to the same period in 2014 and lower natural gas prices across the year.

DISCUSSION OF SEGMENTED COMPARABLE RESULTS

During the first quarter of 2015 we began reporting Canadian Coal, U.S. Coal, Gas, Wind, and Hydro as separate business segments. Previously, these were collectively reported as the Generation Segment and were further differentiated by fuel type within our MD&A to provide additional information to our readers. As a result, the change in segmentation under IFRS has minimal impact on our MD&A. No changes arose in respect of our Energy Marketing and Corporate Segments. See the Current Accounting Changes section of this MD&A for additional information.

Solar facilities acquired during the quarter have been included in our Wind Segment. Please refer to the Significant and Subsequent Events section of this MD&A for further details.

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 Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Availability (%)	**85.7**	88.6	**81.6**	87.6
Contract production (GWh)	**5,521**	5,401	**14,702**	15,664
Merchant production (GWh)	**807**	999	**2,786**	2,860
Total production (GWh)	**6,328**	6,400	**17,488**	18,524
Gross installed capacity (MW)	**3,786**	3,771	**3,786**	3,771
Revenues	**253**	260	**704**	750
Fuel and purchased power	**100**	113	**282**	323
Comparable gross margin[1]	**153**	147	**422**	427
Operations, maintenance, and administration	**51**	52	**148**	148
Taxes, other than income taxes	**3**	3	**9**	9
Other net operating (income)	**(2)**	-	**(2)**	-
Comparable EBITDA[1]	**101**	92	**267**	270
Depreciation and amortization	**78**	72	**224**	216
Comparable operating income[1]	**23**	20	**43**	54
Sustaining capital:				
Routine capital	**14**	13	**37**	38
Mining equipment and land purchases	**5**	19	**17**	27
Finance leases	**3**	3	**9**	7
Planned major maintenance	**22**	17	**99**	81
Total	**44**	52	**162**	153

Production for the three and nine months ended Sept. 30, 2015 decreased 72 GWh and 1,036 GWh, respectively, compared to the same periods in 2014, primarily due to unplanned outages in the first half of the year (unit 4 at Sundance and unit 1 at Keephills) and derates due to high temperatures impacting cooling ponds. The planned outage at Sundance 3 was extended this year as a result of the level of turbine work found and was completed in the early part of the third quarter. We also completed planned outages and Sundance 5 and Keephills 3 during the quarter.

Comparable EBITDA in the third quarter was $101 million and $267 million on a year-to-date basis, compared to $92 million and $270 million, respectively, for the same periods in 2014. Our high level of contracts and hedges in Canadian Coal mostly offset the impact of lower price in Alberta compared to last year. The reductions in operating expenses at our power plants and at our Highvale mine and mark-to-market gains on certain forward financial contracts that do not qualify for hedge accounting fully offset the negative impact of lower availability and lower price on our comparable EBITDA. Lower availability had a larger impact in the first half of 2015.

Depreciation and amortization for the three and nine months ended Sept. 30, 2015 increased by $6 million and $8 million, respectively, compared to the same periods in 2014 due to higher asset retirements during 2015 in connection with planned maintenance activities.

(1) 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.

For the three months ended Sept. 30, 2015, sustaining capital expenditures decreased by $8 million compared to the same period last year. In 2014, we incurred additional costs through the acquisition and refurbishment of vehicles for our mining operations. Year-to-date sustaining capital increased $9 million compared to last year due to the cost to repair Keephills 1 which we expect will be recovered under our insurance program and the timing of a planned outage, partially offset by a decrease in mining expenditures. All planned outages for 2015 have been completed.

U.S. Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Availability (%)	**99.7**	96.9	**87.1**	80.3
Adjusted availability (%)[1]	**99.7**	96.9	**89.8**	86.9
Contract sales volume (GWh)	**704**	-	**2,089**	496
Merchant sales volume (GWh)	**2,021**	2,873	**3,357**	5,098
Purchased power (GWh)	**(849)**	(619)	**(2,298)**	(854)
Total production (GWh)	**1,876**	2,254	**3,148**	4,740
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**146**	109	**293**	259
Fuel and purchased power	**121**	84	**210**	176
Comparable gross margin	**25**	25	**83**	83
Operations, maintenance, and administration	**15**	11	**37**	35
Taxes, other than income taxes	**-**	1	**2**	2
Comparable EBITDA	**10**	13	**44**	46
Depreciation and amortization	**15**	13	**47**	40
Comparable operating income (loss)	**(5)**	-	**(3)**	6
Sustaining capital:				
Routine capital	**1**	2	**2**	3
Finance leases	**1**	-	**2**	-
Planned major maintenance	**1**	-	**10**	9
Total	**3**	2	**14**	12

Production decreased 378 GWh and 1,592 GWh, respectively, for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 due mainly to the lower power prices in the first and third quarters of 2015. These lower prices provided us the opportunity to shut down or dial down our generation and supply our contractual obligation by buying cheaper power in the market.

In December 2014, we commenced supplying power to Puget Sound Energy under a 10-year contract. Contracted capacity currently is 180 MW, escalating to 280 MW in December, and the contract price is currently higher than prevailing market prices in the Pacific Northwest. We can also re-supply the contract by buying power from the market when economical to do so and further improve our margin.

(1) Adjusted for economic dispatching.

Despite the benefits of this contract, comparable EBITDA for the three and nine months ended Sept. 30, 2015 decreased by $3 million and $2 million, respectively, compared to the same periods in 2014. During the quarter, EBITDA was negatively affected by coal inventory writedowns of $17 million (three month period ended Sept. 30, 2014 - $7 million) and reduced generation resulting from low power prices, which were partially offset by mark-to-market gains on financial contracts put in place to hedge our future generation and the strengthening of the US dollar. For the year-to-date, limited merchant sales and mark-to-market losses were partially offset by the appreciation of the US dollar. We anticipate the effects of coal inventory writedowns to reverse during the fourth quarter as coal is used for production.

Depreciation and amortization for the three and nine months ended Sept. 30, 2015 increased by $2 million and $7 million, respectively, compared to the same periods in 2014 due to the strengthening of the US dollar.

Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Availability (%)	**93.3**	93.7	**94.6**	92.9
Contract production (GWh)	**1,309**	1,428	**4,014**	4,157
Merchant production (GWh)	**365**	292	**1,420**	1,410
Total production (GWh)	**1,674**	1,720	**5,434**	5,567
Gross installed capacity (MW)[1]	**1,405**	1,779	**1,405**	1,779
Revenues	**161**	162	**496**	575
Fuel and purchased power	**57**	60	**183**	266
Comparable gross margin	**104**	102	**313**	309
Operations, maintenance, and administration	**24**	25	**71**	75
Taxes, other than income taxes	**-**	-	**2**	2
Comparable EBITDA	**80**	77	**240**	232
Depreciation and amortization	**28**	29	**83**	85
Comparable operating income	**52**	48	**157**	147
Sustaining capital:				
Routine capital	**3**	5	**7**	13
Planned major maintenance	**11**	15	**23**	39
Total	**14**	20	**30**	52

As a substantial portion of revenue in the Gas Segment is attributable to the transfer of gas costs to our customers, revenue and costs of fuel have decreased by similar amounts during the first half of 2015 compared to last year, following the decrease in gas input costs. The increase in comparable EBITDA is primarily attributable to revenue from the Australian natural gas pipeline, which was commissioned in March 2015. Revenue from our Solomon facility was also positively impacted by the appreciation of the US dollar.

Sustaining capital decreased by $6 million and $22 million, respectively, for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 as a result of fewer planned maintenance activities. In 2014, planned maintenance outages occurred at our Ottawa and Sarnia facilities.

(1) Includes production capacity for Fort Saskatchewan and Solomon power stations, which have been accounted for as finance leases. During the quarter, 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. Please refer to the Significant and Subsequent Events section of this MD&A for further information. Assets of the Centralia gas plant were sold in the fourth quarter of 2014 and the production capacity was removed from our gross capacity measures at that time.

Wind *[1]*

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Availability (%)	**95.7**	94.6	**95.3**	94.1
Contract production (GWh)	**339**	380	**1,427**	1,576
Merchant production (GWh)	**200**	152	**697**	617
Total production (GWh)	**539**	532	**2,124**	2,193
Gross installed capacity (MW)	**1,375**	1,289	**1,375**	1,289
Revenues	**38**	43	**160**	172
Fuel and purchased power	**3**	3	**9**	10
Comparable gross margin	**35**	40	**151**	162
Operations, maintenance, and administration	**11**	11	**35**	34
Taxes, other than income taxes	**1**	2	**5**	5
Comparable EBITDA	**23**	27	**111**	123
Depreciation and amortization	**26**	22	**70**	66
Comparable operating income (loss)	**(3)**	5	**41**	57
Sustaining capital:				
Routine capital	**1**	1	**1**	2
Planned major maintenance	**4**	1	**10**	5
Total	**5**	2	**11**	7

Contract production for the three and nine months ended Sept. 30, 2015 decreased 41 GWh and 149 GWh, respectively compared to the same periods in 2014, primarily due to lower wind volumes in Eastern Canada throughout the period and at our Wyoming wind facility in the first half of 2015. Higher wind volumes and availability at Western Canada merchant facilities have partially offset the lower volumes from contracted facilities. Year-over-year lower prices in Alberta have impacted the financial performance of our Wind Segment during the first and third quarters of 2015 as we generally do not hedge our merchant wind generation.

During the quarter, we completed the acquisition of two wind farms in Alberta and Ontario and our first solar facility in Massachusetts. The three projects generated 14 GWh during the period and a nominal contribution to EBITDA.

Depreciation and amortization for the three and nine months ended Sept. 30, 2015 increased by $4 million in each period compared to the same periods in 2014 due to higher asset retirements in connection with planned maintenance activities and an increase in asset base during 2015.

Sustaining capital expenditures increased by $3 million and $4 million, respectively, for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 due to an increase in planned outages.

(1) Wind Segment includes results of solar facilities.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Contract production (GWh)	**381**	503	**1,286**	1,393
Merchant production (GWh)	**41**	36	**79**	64
Total production (GWh)	**422**	539	**1,365**	1,457
Gross installed capacity (MW)	**913**	913	**913**	913
Revenues	**28**	40	**91**	104
Fuel and purchased power	**2**	4	**6**	8
Comparable gross margin	**26**	36	**85**	96
Operations, maintenance, and administration	**9**	9	**28**	28
Taxes, other than income taxes	**2**	-	**3**	2
Other net operating (income)	**-**	-	**-**	(1)
Comparable EBITDA	**15**	27	**54**	67
Depreciation and amortization	**7**	6	**19**	18
Comparable operating income	**8**	21	**35**	49
Sustaining capital:				
Routine capital	**3**	2	**14**	6
Planned major maintenance	**3**	1	**6**	1
Total before flood-recovery capital	**6**	3	**20**	7
Flood-recovery capital	**1**	-	**1**	7
Total	**7**	3	**21**	14

Production for the three months ended Sept. 30, 2015 decreased by 117 GWh compared to the same period in 2014 as a result of low market prices and economic dispatching in Alberta.

Comparable EBITDA decreased by $12 million and $13 million, respectively, for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014, primarily as a result of lower prices and a decrease in price volatility in Alberta during the first and third quarters, which limited our ability to take advantage of our flexibility to produce electricity in higher priced hours.

Sustaining capital expenditures increased by $4 million and $7 million, respectively, for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 mainly due to hydro life extension costs, which were classified as growth capital expenditures last year.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Revenues and comparable gross margin	**10**	3	**24**	76
Operations, maintenance, and administration	**4**	7	**13**	27
Comparable EBITDA and operating income (loss)	**6**	(4)	**11**	49

For the three months ended Sept. 30, 2015, comparable EBITDA and operating income (loss) increased by $10 million compared to the same period in 2014 due to a return to normal level of gross margin from short-term strategies and solid performance in the western U.S. This represents a return to expected performance from our Energy Marketing activities. Our expectation for our Energy Marketing Segment is to generate $10 to $15 million of gross margin every quarter. The increase in comparable EBITDA was also attributed to a decrease in operating costs, which includes reduced performance-based compensation costs in 2015 due to lower gross margins.

For the nine months ended Sept. 30, 2015, comparable EBITDA and operating income decreased by $38 million compared to the same period in 2014 largely due to extraordinary market conditions in the first quarter of last year that resulted in substantial customer margins and volatile market conditions in the Alberta and Pacific Northwest regions in the second quarter of this year that negatively affected our Energy Marketing results. Negative second quarter results were offset by the performance in the current quarter. The decrease in the gross margin was partially offset by a decrease in operating costs.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Operations, maintenance, and administration and taxes other than income taxes	**16**	20	**50**	52
Depreciation and amortization	**7**	7	**20**	20
Comparable operating loss	**23**	27	**70**	72
Sustaining capital:				
Routine capital	**6**	5	**15**	17
Total	**6**	5	**15**	17

For the three and nine months ended Sept. 30, 2015, corporate costs decreased compared to the same periods in 2014 as a result of legal costs incurred relating to the MSA proceeding in front of the AUC in 2014.

Routine capital expenditures for the nine months ended Sept. 30, 2015 decreased compared to the same period in 2014, mainly resulting from a reduction in corporate information technology costs.

OTHER CONSOLIDATED RESULTS

Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Interest on debt	**57**	60	**170**	179
Capitalized interest	**(1)**	(1)	**(6)**	(1)
Interest on finance lease obligations	**2**	-	**3**	-
Accretion of provisions	**5**	5	**15**	14
Net interest expense	**63**	64	**182**	192

Net interest expense was lower for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 due to lower interest rates, and higher capitalized interest. These impacts were partially offset by higher interest on our US-denominated debt due to the strengthening of the US dollar.

Income Taxes

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

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2015	2014	**2015**	2014
Earnings (loss) before income taxes	**219**	31	**175**	90
Comparable adjustments:				
Impacts associated with certain de-designated and ineffective hedges	**(26)**	(35)	**47**	(7)
Asset impairment charges (reversals)	**-**	(1)	**(1)**	(1)
Gain on sale of assets	**-**	-	**-**	(1)
Economic hedges of non-controlling interest in intercompany foreign exchange contracts	**(1)**	-	**-**	
Flood-related maintenance costs, net of insurance recovery	**-**	4	**1**	5
Restructuring	**11**	-	**18**	-
Foreign exchange loss on California claim	**-**	2	**-**	2
Gain on Poplar Creek contract restructuring	**(263)**	-	**(263)**	-
Other net operating (income) losses	**56**	-	**56**	5
Comparable earnings (loss) before tax	**(4)**	1	**33**	93
Comparable (earnings) attributable to non-controlling interests before tax	**(11)**	(9)	**(42)**	(37)
Comparable earnings (loss) attributable to TransAlta shareholders subject to tax	**(15)**	(8)	**(9)**	56
Comparable income tax expense adjustments:				
Income tax (recovery) expense related to impacts associated with certain de-designated and ineffective hedges	**(9)**	(12)	**16**	(2)
Income tax recovery related to gain on sale of assets	**-**	-	**-**	1
Income tax recovery related to sale of investment	**-**	-	**-**	36
Deferred income tax rate adjustment	**-**	-	**(20)**	-
Income tax recovery (expense) related to reversal (accrual) of a writedown of deferred income tax assets	**50**	(12)	**62**	(63)
Income tax expense related to the Transaction	**-**	-	**(48)**	-
Income tax expense related to flood-related maintenance costs, net of insurance recovery	**-**	1	**-**	1
Income tax recovery related to restructuring	**3**	-	**5**	-
Income tax recovery related to foreign exchange loss on California claim	**-**	1	**-**	1
Income tax expense related to gain on Poplar Creek contract restructuring	**(70)**	-	**(70)**	-
Income tax recovery related to other net operating (income) losses	**1**	-	**1**	1
Total comparable income tax expense adjustments	**(25)**	(22)	**(54)**	(25)
Income tax expense (recovery)	**31**	18	**62**	33
Comparable income tax expense (recovery)	**6**	(4)	**8**	8
Comparable income tax (expense) attributable to non-controlling interests	**-**	-	**(1)**	(2)
Comparable income tax expense (recovery) attributable to TransAlta shareholders	**6**	(4)	**7**	6
Comparable effective tax rate on earnings attributable to TransAlta shareholders (%)	**(40)**	50	**(78)**	11

The comparable income tax expense attributable to TransAlta shareholders increased for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014 due to certain amounts that do not fluctuate with earnings, offset by changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

For the three and nine months ended Sept. 30, 2015, the comparable effective tax rate on earnings attributable to TransAlta shareholders changed, compared to the same periods in 2014, as a result of the effect of certain deductions that do not fluctuate with earnings, offset by changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

During the three and nine months ended Sept. 30, 2015, we reversed a previous writedown of deferred income tax assets of $50 million (Sept. 30, 2014 - $13 million writedown recognized) and $62 million (Sept. 30, 2014 - $27 million writedown recognized), respectively. The deferred income tax assets relate mainly 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. Recognized other comprehensive income in the during the three and nine months ended Sept. 30, 2015 has given rise to a taxable temporary difference 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 Transaction with TransAlta Renewables, a reorganization of certain TransAlta companies was completed. The reorganization resulted in the recognition in the first and second quarter of 2015 of $8 million and $40 million deferred tax liability, respectively, on our 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.

During the second quarter of 2015, the Government of Alberta enacted legislation to increase its provincial corporate income tax rate to 12 per cent from 10 per cent, effective July 1, 2015, resulting in a net increase in our deferred income tax liability of $18 million. Of which, $20 million is recorded in the Condensed Consolidated Statement of Earnings with an offsetting $2 million deferred tax recovery recorded in the Condensed Statement of Other Comprehensive Income.

Non-Controlling Interests

Net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2015 increased by $12 million compared to the same periods in 2014 primarily due to unrealized gains on intercompany financial instruments by TransAlta Renewables. On a comparable basis, earnings attributable to non-controlling interests have increased compared to prior periods due to higher TransAlta Renewables earnings, partially offset by a lower proportion thereof being attributable to non-controlling interests and by an additional outage in 2015 that decreased earnings at TransAlta Cogeneration L.P. (“TA Cogen”). As a result of the closing of the Transaction, the non-controlling interests’ equity participation in TransAlta Renewables decreased to 27.2 per cent from 29.7 per cent while growing in value. Refer to *Note 3* of our condensed consolidated financial statements for additional information.

ADDITIONAL 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 for the three and nine months ended Sept. 30, 2015 and 2014. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

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.

The adjustments made to calculate comparable EBITDA and comparable earnings for the three and nine months ended Sept. 30, 2015 and 2014 are as follows. References are to the reconciliation presented on the following page.

			3 months ended Sept. 30		9 months ended Sept. 30	
			2015	2014	**2015**	2014
Reference number	**Adjustment**	**Segment**				
Reclassifications:						
1	Finance lease income used as a proxy for operating revenue	Gas	**15**	12	**41**	36
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Gas	**6**	1	**8**	2
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	**16**	13	**46**	41
Adjustments to earnings to arrive at comparable results:						
4	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	**(26)**	(35)	**47**	(7)
5	Restructuring expense	Canadian Coal	**2**	-	**9**	-
		U.S. Coal	**1**	-	**1**	-
		Gas	**1**	-	**1**	-
		Energy Marketing	**3**	-	**3**	-
		Corporate	**4**	-	**4**	-
6	MSA provision	Energy Marketing	**56**	-	**56**	-
7	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	**(1)**	-	**-**	-
8	Gain on Poplar Creek contract restructuring	Gas	**(263)**	-	**(263)**	-
9	Net tax effect of comparable adjustments subject to tax	Unassigned	**75**	10	**48**	(2)
10	(Reversal) accrual of writedown of deferred income tax assets	Unassigned	**(50)**	12	**(62)**	63
11	Income tax expense related to the Transaction	Unassigned	**-**	-	**48**	-
12	Deferred income tax rate adjustment	Unassigned	**-**	-	**20**	-
13	Non-comparable items attributable to non-controlling interest	Unassigned	**11**	1	**7**	1
14	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	**-**	4	**1**	6
15	Asset impairment charges (reversals)	Gas	**-**	(1)	**(1)**	(1)
16	Foreign exchange on California claim	Unassigned	**-**	2	**-**	2
17	Non-comparable portion of insurance recovery received	Hydro	**-**	-	**-**	(1)
18	California claim	Energy Marketing	**-**	-	**-**	5
19	Non-comparable gain on sale of assets	Equity Investments	**-**	-	**-**	(1)
20	Income tax recovery related to sale of investment	Unassigned	**-**	-	**-**	(36)

A reconciliation of comparable results to reported results for the three and nine months ended Sept. 30, 2015 and 2014 is as follows:

	3 months ended Sept. 30, 2015				3 months ended Sept. 30, 2014			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**641**	**21** [1,2]	**(26)** [4]	**636**	639	13 [1,2]	(35) [4]	617
Fuel and purchased power	**299**	**(16)** [3]	**-**	**283**	277	(13) [3]	-	264
Gross margin	**342**	**37**	**(26)**	**353**	362	26	(35)	353
Operations, maintenance, and administration	**130**	**-**	**-**	**130**	138	-	(4) [14]	134
Asset impairment charges (reversals)	**-**	**-**	**-**	**-**	(1)	-	1 [15]	-
Restructuring provision	**11**	**-**	**(11)** [5]	**-**	-	-	-	-
Taxes, other than income taxes	**6**	**-**	**-**	**6**	7	-	-	7
Net other operating (income) losses	**54**	**-**	**(56)** [6]	**(2)**	-	-	-	-
EBITDA	**141**	**37**	**41**	**219**	218	26	(32)	212
Depreciation and amortization	**139**	**22** [2,3]	**-**	**161**	135	14 [2,3]	-	149
Operating income (loss)	**2**	**15**	**41**	**58**	83	12	(32)	63
Finance lease income	**15**	**(15)** [1]	**-**	**-**	12	(12) [1]	-	-
Foreign exchange gain (loss)	**2**	**-**	**(1)** [7]	**1**	-	-	2 [16]	2
Gain on sale of assets	**263**	**-**	**(263)** [8]	**-**	-	-	-	-
Earnings (loss) before interest and taxes	**282**	**-**	**(223)**	**59**	95	-	(30)	65
Net interest expense	**63**	**-**	**-**	**63**	64	-	-	64
Income tax expense (recovery)	**31**	**-**	**(25)** [9,10]	**6**	18	-	(22) [9,10]	(4)
Net earnings (loss)	**188**	**-**	**(198)**	**(10)**	13	-	(8)	5
Non-controlling interests	**22**	**-**	**(11)** [13]	**11**	10	-	(1) [13]	9
Net earnings (loss) attributable to TransAlta shareholders	**166**	**-**	**(187)**	**(21)**	3	-	(7)	(4)
Preferred share dividends	**12**	**-**	**-**	**12**	9	-	-	9
Net earnings (loss) attributable to common shareholders	**154**	**-**	**(187)**	**(33)**	(6)	-	(7)	(13)
Weighted average number of common shares outstanding in the period	**281**			**281**	273			273
Net earnings (loss) per share attributable to common shareholders	**0.55**			**(0.12)**	(0.03)			(0.05)

	9 months ended Sept. 30, 2015				9 months ended Sept. 30, 2014			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**1,672**	**49** [1,2]	**47** [4]	**1,768**	1,905	38 [1,2]	(7) [4]	1,936
Fuel and purchased power	**736**	**(46)** [3]	**-**	**690**	824	(41) [3]	-	783
Gross margin	**936**	**95**	**47**	**1,078**	1,081	79	(7)	1,153
Operations, maintenance, and administration	**383**	**-**	**(1)** [14]	**382**	404	-	(6) [14]	398
Asset impairment charges (reversals)	**(1)**	**-**	**1** [15]	**-**	(1)	-	1 [15]	-
Restructuring provision	**18**	**-**	**(18)** [5]	**-**	-	-	-	-
Taxes, other than income taxes	**21**	**-**	**-**	**21**	21	-	-	21
Other net operating (income) losses	**54**	**-**	**(56)** [6]	**(2)**	3	-	(4) [17,18]	(1)
EBITDA	**461**	**95**	**121**	**677**	654	79	2	735
Depreciation and amortization	**409**	**54** [2,3]	**-**	**463**	402	43 [2,3]	-	445
Operating income	**52**	**41**	**121**	**214**	252	36	2	290
Finance lease income	**41**	**(41)** [1]	**-**	**-**	36	(36) [1]	-	-
Foreign exchange gain (loss)	**1**	**-**	**-**	**1**	(7)	-	2 [16]	(5)
Gain on sale of assets	**263**	**-**	**(263)** [8]	**-**	1	-	(1) [19]	-
Earnings before interest and taxes	**357**	**-**	**(142)**	**215**	282	-	3	285
Net interest expense	**182**	**-**	**-**	**182**	192	-	-	192
Income tax expense (recovery)	**62**	**-**	**(54)** [9,10,11,12]	**8**	33	-	(25) [9,10,20]	8
Net earnings (loss)	**113**	**-**	**(88)**	**25**	57	-	28	85
Non-controlling interests	**48**	**-**	**(7)** [13]	**41**	36	-	(1) [13]	35
Net earnings (loss) attributable to TransAlta shareholders	**65**	**-**	**(81)**	**(16)**	21	-	29	50
Preferred share dividends	**35**	**-**	**-**	**35**	28	-	-	28
Net earnings (loss) attributable to common shareholders	**30**	**-**	**(81)**	**(51)**	(7)	-	29	22
Weighted average number of common shares outstanding in the period	**279**			**279**	272			272
Net earnings (loss) per share attributable to common shareholders	**0.11**			**(0.18)**	(0.03)			0.08

FINANCIAL INSTRUMENTS

Refer to *Note 13* of the notes to the audited annual consolidated financial statements within our 2014 Annual Report and *Note 8* of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2015 for details on Financial Instruments. Refer to the Risk Management section of our 2014 Annual Report and *Note 9* of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2014.

We may enter into commodity transactions involving non-standard features for which market observable 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 Sept. 30, 2015, total Level III financial instruments had a net asset carrying value of $517 million (Dec. 31, 2014 - $217 million net asset). The increase during the period is attributable primarily to decreased 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.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk arises from our ability to meet general funding needs, engage in trading and hedging activities, and manage the assets, liabilities, and capital structure of the Corporation. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner. Liquidity risk related to commodity risk management activities is managed by maintaining sufficient reserves and monitoring our counterparties and the markets in which we transact.

Our liquidity needs are met through a variety of sources, including cash generated from operations, availability under our long-term credit facilities, and long-term debt or equity issued under our Canadian and U.S. shelf registrations. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling interests, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.5 billion as at Sept. 30, 2015 compared to $4.1 billion as at Dec. 31, 2014. Long-term debt increased from Dec. 31, 2014 primarily due to strengthening of the US dollar ($312 million) and an increase in non-recourse debt associated with the acquisition of the solar facilities in Massachusetts ($55 million). As at Sept. 30, 2015, $1.7 billion of our debt is denominated in US dollars (Dec. 31, 2014 - $2.1 billion).

On Sept. 1, 2015, our $120 million 5.33 per cent unsecured debentures matured and were paid out using existing liquidity. We also closed the acquisition of solar assets and assumed approximately US$42 million of non-recourse variable rate debt, of which approximately US$32 million is hedged to a fixed rate of 4.698 per cent.

On Oct. 1, 2015, TransAlta Renewables closed a $442 million bond offering. The bonds are amortizing and bear interest at a rate of 3.834 per cent, payable semi-annually and mature on Dec. 31, 2028. Net proceeds of the financing will be used to reduce the draw down on our credit facilities.

During the second quarter, we applied the net proceeds of $211 million received from the sale of an economic interest in our Australian portfolio to reduce the draw down on our credit facilities.

Almost all of our US-denominated debt is hedged either through financial contracts or as a natural hedge of our net investment in our U.S. operations. For the three and nine months ended Sept. 30, 2015, the changes in our US-denominated debt were offset as follows:

	3 months ended Sept. 30, 2015	**9 months ended Sept. 30, 2015**
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge)	52	105
Foreign currency cash flow hedges on debt	82	149
Effects of foreign exchange on value of US-denominated Solomon finance lease	30	54
Other economic hedges	2	4
Total	**166**	**312**

Credit Facilities

As at Sept. 30, 2015, we had a total of $2.1 billion (Dec. 31, 2014 - $2.1 billion) of committed credit facilities, of which $0.9 billion (Dec. 31, 2014 - $1.6 billion) is available, subject to customary borrowing conditions. As at Sept. 30, 2015, the $1.2 billion (Dec. 31, 2014 - $0.5 billion) of credit utilized under these facilities was comprised of actual drawings of $0.8 billion (Dec. 31, 2014 - $0.1 billion) and letters of credit of $0.4 billion (Dec. 31, 2014 - $0.4 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2019, with the remainder comprised of bilateral credit facilities, of which $0.3 billion matures in 2017 and $0.2 billion matures in the fourth quarter of 2016. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.9 billion available under the credit facilities, we have $37 million of available cash (Dec. 31, 2014 - $43 million).

Share Capital

On Oct. 29, 2015, we had 284.1 million common shares issued and outstanding, 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G preferred shares outstanding. As at Sept. 30, 2015, we had 280.6 million (Sept. 30, 2014 - 273.4 million) common shares issued and outstanding. As at Sept. 30, 2015, we had 38.6 million (Sept. 30, 2014 - 38.6 million) first preferred shares issued and outstanding.

During the three and nine months ended Sept. 30, 2015, 1.9 million and 5.6 million, respectively (Sept. 30, 2014 - 1.6 million and 5.2 million, respectively), common shares were issued to shareholders that elected dividend reinvestment, for a total of $19 million and $57 million, respectively (Sept. 30, 2014 - $19 million and $65 million, respectively).

On Oct. 29, 2015, we declared a quarterly dividend of $0.18 per common share, payable on Jan. 1, 2016. Declaration of dividends is at the discretion of the Board of Directors.

On Oct. 29, 2015, we declared 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 Dec. 31, 2015.

Letters of Credit and Cash Collateral

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, unfunded pension obligations, construction projects, and purchase obligations. As at Sept. 30, 2015, we provided letters of credit and cash collateral totalling $489 million (Dec. 31, 2014 - $421 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Position for risk management liabilities, decommissioning and other provisions, and defined benefit obligations.

Financial Position

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2014 to Sept. 30, 2015:

	Increase/ (decrease)	Primary factors explaining change
Trade and other receivables	44	Timing of customer receipts, including seasonality of revenue and changes in collateral
Prepaid expenses	24	Prepayment of annual insurance premiums, royalties, and service agreements
Inventory	51	Increase in coal inventory at U.S. Coal and Canadian Coal following lower production
Finance lease receivables (long-term)	367	Poplar Creek contract restructuring
Property, plant, and equipment, net	(30)	Net effect of Poplar Creek contract restructuring ($141 million), depreciation for the period ($402 million), and revisions and additions to decommissioning and restoration costs ($30 million), partially offset by the acquisition of solar assets ($107 million), additions ($375 million) and favourable changes in foreign exchange rates ($75 million)
Intangible assets	36	Acquisition of Kent Breeze wind farm through the Poplar Creek contract restructuring
Deferred income tax assets	35	Effect of the internal reorganization associated with the Transaction and an increase in deductible temporary differences
Risk management assets and liabilities (current and long-term), net	338	Gains on commodity and foreign currency cash flow hedges
Other assets	19	Reclassification of Washington state community investment contribution funded but not yet disbursed
Other	39	
Total increase in assets	923	
Accounts payable and accrued liabilities	(95)	Timing of payments and accruals
Credit facilities, long-term debt, and finance lease obligations (including current portion)	394	Unfavourable effects of changes in foreign exchange rates and increase in non-recourse debt associated with acquisition of solar facilities ($55 million) and financing of equity to acquire project ($51 million)
Decommissioning and other provisions (current and long-term)	46	MSA provision ($56 million)
Deferred income tax liabilities	154	Increase in Alberta corporate tax rate and the effect of the internal reorganization associated with the Transaction and an increase in taxable temporary differences
Equity attributable to shareholders	169	Gains on cash flow hedges and gains on translating net assets of foreign operations recognized in other comprehensive income, net earnings for the period, and issuance of common shares, partially offset by dividends declared in the period and sale of investment in subsidiaries to TransAlta Renewables
Non-controlling interests	211	Sale of investment in subsidiaries to TransAlta Renewables and net earnings for the period, partially offset by distributions paid and payable to non-controlling interests
Other	44	
Total increase in liabilities and equity	923	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2015 compared to the same periods in 2014:

3 months ended Sept. 30	**2015**	2014	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**71**	94	
Provided by (used in):			
Operating activities	**200**	216	Decrease cash earnings of $21 million, partially offset by an increase in working capital of $5 million
Investing activities	**(166)**	(158)	Acquisition of solar assets in Massachusetts for $51 million, partially offset by an increase in investing non-cash working capital balances of $20 million and a decrease in additions to PP&E and intangibles of $15 million
Financing activities	**(68)**	94	Decrease in net proceeds on issuance of preferred shares of $161 million
Translation of foreign currency cash	**-**	(1)	
Cash and cash equivalents, end of period	**37**	245	

9 months ended Sept. 30	**2015**	2014	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**43**	42	
Provided by (used in):			
Operating activities	**314**	546	Further decrease in working capital of $216 million and a decrease in cash earnings of $16 million
Investing activities	**(425)**	(137)	A decrease in proceeds on sale of investment of $218 million, an increase in additions to PP&E and intangibles of $52 million, and an acquisition of solar assets for $51 million, partially offset by an increase in realized gains on financial instruments of $17 million
Financing activities	**104**	(206)	Reduction in the net decrease in borrowings of $331 million, an increase in proceeds on the sale of non-controlling interest in subsidiary of $82 million, and an increase in realized gains on financial instruments of $60 million, partially offset by a decrease in net proceeds on issuance of preferred shares of $161 million
Translation of foreign currency cash	**1**	-	
Cash and cash equivalents, end of period	**37**	245	

CLIMATE CHANGE AND THE ENVIRONMENT

Environmental issues and related legislation have, and will continue to have, an impact upon our business. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development. Refer to the Climate Change and the Environment section of our 2014 Annual MD&A for further details.

Recent Regulatory Developments

Alberta

On June 29, 2015, the Alberta Government announced an increase to its provincial SGER.

- On Jan 1, 2016, an increase in the greenhouse gas ("GHG") reduction obligation for large emitters from 12 per cent to 15 per cent of emissions, with the compliance price of the technology fund rising from $15 per tonne to $20 per tonne.
- On Jan. 1, 2017, a further increase to a 20 per cent reduction requirement and a $30 per tonne compliance price.

At the same time, the Alberta Government announced an intention to develop a broader climate change program which could result in greater emissions reductions over time. That program is to be developed by the fall of 2015 through consultations with Albertans and advice from an independent expert panel. It is not clear at this time if this broader climate change program will supplant the SGER framework or be incremental to it.

The GHG offsets created by our Alberta wind facilities are expected to increase in value through 2017, as GHG emitters can use them as compliance instruments in place of contributing to the technology fund.

On Oct. 1, 2015, we submitted a proposal to the Alberta Climate Change Advisory Panel that would see a "Dial Down" of coal-based electricity generation while the province "Dials Up" renewables-based generation. The proposal would impose a hard cap on GHG emissions from coal-fired generation. Coal plants would operate at reduced capacity starting in 2016 while maintaining base load generation levels during the transition. At the same time, the proposal would facilitate accelerated investment in renewables generation, including hydro, wind, and solar generation. TransAlta is already Canada's largest wind power generator and has Alberta's largest hydro operations.

TransAlta is committed to working with all stakeholders, including environmental groups, communities and our unions, to develop a solution that would enable the province to achieve its GHG reduction targets, protect consumers from high power prices, accelerate renewables generation, protect jobs, and support economic growth.

Ontario

On April 13, 2015, the Ontario Government announced that Ontario will be implementing a GHG cap-and-trade system in an effort to reduce emissions and fight climate change. The cap and trade system will impose a hard ceiling on the GHG emissions allowed in each sector of the economy. The details of the cap and trade system (such as specifics on a potential cap, covered sectors, or anticipated launch date) have not been determined but are to be developed through stakeholder consultations. Our contracts at Gas facilities in the province generally include provisions protecting us from adverse changes in laws.

United States

On Aug. 3, 2015, President Obama announced the Clean Power Plan. The plan sets GHG emission standards for new fossil-fuel based power plants and emission limits for individual states. States will have the option of interpreting their limits in mass-based (tons) or rate-based (pounds per megawatt hour) terms. The plan is intended to achieve an overall reduction in GHG emissions of 32 per cent from 2005 levels by 2030. It will be implemented in two stages: 2022 to 2029, and 2030 and beyond.

The plan is not expected to have any impact on U.S. Coal, as we are exempted from such regulations based on the 2011 agreement between Washington state and TransAlta.

2015 OUTLOOK

Based on year-to-date results and our forecast for the fourth quarter of 2015, combined with the deferral of a planned major maintenance outage at U.S. Coal, we have revised our outlook on full year 2015 Comparable EBITDA, Comparable FFO, and sustaining capital expenditures around the low end of previously communicated ranges. The outlook on comparable FCF has been revised to slightly exceed the previously communicated range.

We now expect comparable EBITDA for 2015 to be in the range of $980 million to $1,010 million based on the current outlook for power prices in Alberta and the Pacific Northwest. Comparable FFO is anticipated to be in the range of $725 million to $755 million. Comparable FCF, excluding the effects of flood-recovery capital, is expected to be in the range of $275 million to $285 million, or $0.98 to $1.02 per share, based on sustaining capital, excluding the effects of flood-recovery capital, of approximately $305 million to $320 million. We anticipate that lower cash interest will be offset by higher distributions to non-controlling interest and preferred share dividends. Our expected dividend is 71 per cent to 73 per cent of comparable FCF.

Market

Power Prices

For the balance of 2015, power prices in Alberta are expected to be comparable with 2014 as increases in supply will be offset by lower natural gas prices. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle lower than in 2014 due to lower natural gas prices. In Ontario, we expect prices to be comparable to 2014 as baseload generation outages will offset lower natural gas prices.

Economic Environment

The slowdown in the oil and gas sector has put Alberta into a recession in 2015, and current conditions are expected to continue for the remainder of the year. However, prices can vary based on supply and weather conditions. In the Pacific Northwest we expect prices to settle lower than in 2014 due to lower natural gas prices. Ontario growth has been moderate in 2015 at around two per cent, and the remainder of the year is expected to be slightly stronger as the export sector gains ground due to the weak Canadian dollar.

We had no material counterparty losses in the third quarter of 2015. We continue to monitor counterparty credit risk and have established risk management policies to mitigate counterparty risk. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase slightly in 2015 primarily due to acquisition of renewable projects which are offset by a decrease in capacity resulting from the transfer of capacity from two steam turbines to Suncor under the Poplar Creek contract restructuring. Overall production is expected to decrease eight to nine per cent in 2015 due to a longer period of economic dispatching in our Centralia coal facility, higher unplanned outages at Canadian Coal, and the restructuring of the Poplar Creek arrangement. Overall availability is expected to be in the range of 89 to 91 per cent in 2015.

Contracted Cash Flows

As a result of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the period to the end of 2020. 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 2014, approximately 88 per cent of our 2015 capacity was contracted. The average prices of our short-term physical and financial contracts for 2015 are approximately $50 per MWh in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost decreases due to effective cost control, and lower commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2015, on a standard cost per tonne basis, are expected to be three to four per cent lower than 2014 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 2015 is expected to increase by approximately one to two per cent as a result of inflation and our coal recovery program.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges are recognized in net earnings.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America could reduce the year-to-year volatility of prices in the near term.

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

Earnings from our Energy Marketing Segment are affected by prices in the market, overall strategies adopted, competitive behaviors from other market participants, 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 2015 objective is for Energy Marketing to contribute between $40 million and $60 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies

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

Net Interest Expense

Net interest expense for 2015 is expected to be lower than in 2014 due to lower debt levels and 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.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities.

Income Taxes

The comparable effective tax rate on earnings for 2015 is expected to be approximately 35 to 40 per cent, which is higher than the statutory tax rate of 25.87 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 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:

	Total Project		2015		Target (actual)	
	Estimated spend	Spent to date(1)	Estimated spend	Spent to date(1)	completion date	Details
Project						
South Hedland Power Station(2)	560	192	178	123	Q2 2017	150 MW combined cycle power plant
Australia natural gas pipeline(3)	98	96	21	19	(Q1 2015)	270 kilometre pipeline to supply natural gas to our Solomon power station in Western Australia
Solomon load bank facility(3)	5	2	3	2	Q2 2016	Installation of 20 MW load bank facility required to complete the Solomon power station
Transmission	17	5	10	3	Q1 2016	Regulated transmission that receives a return on investment
Total	**680**	**295**	**212**	**147**		

The estimated project spend for 2015 for the Solomon load bank facility decreased by $2 million and the target completion date has been revised during the quarter as a result of delays in the project.

The estimated project spend for 2015 for transmission decreased by $5 million during the quarter as a result of a deferral of part of the project into 2016.

(1) Represents amounts spent as of Sept. 30, 2015.

(2) Estimated project spend is AUD$570 million. Total estimated project spend is stated in CAD$ and includes estimated capitalized interest costs. The total estimated project spend may change due to fluctuations 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.

Sustaining and Productivity Expenditures

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

Category	Description	Expected cost	Spent to date[1]
Routine capital[2]	Capital required to maintain our existing generating capacity	100 - 105	76
Planned major maintenance	Regularly scheduled major maintenance	165 - 175	148
Mining capital	Capital related to mining equipment and land purchases	25 - 25	17
Finance leases	Payments on finance leases	15 - 15	11
Total sustaining capital excluding flood-recovery capital		**305 - 320**	**252**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	0 - 5	1
Total sustaining capital		**305 - 325**	**253**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	5 - 10	5
Total sustaining and productivity capital		**310 - 335**	**258**

During the quarter, flood-recovery expenditures were deferred to 2016. We continue to anticipate that most flood-recovery capital expenditures related to the Alberta flood in 2013 will be recovered from third parties.

As a result of lower generation from our U.S. Coal assets we decided to defer a planned major maintenance outage at one of our units, reducing our estimated sustaining capital for the current year by over $15 million.

The expected cost of planned major maintenance for the year includes $12 million associated with major maintenance at Poplar Creek, which was incurred prior to the close of the contractual restructuring described in the Significant and Subsequent Events section of this MD&A. Our customer assumes capital obligations of the facility arising after closing, and on an ongoing basis thereafter.

Lost production as a result of planned major maintenance, excluding planned major maintenance for U.S. Coal, which was scheduled during a period of economic dispatching, was estimated as follows for 2015:

	Coal	Gas and Renewables	Total	Lost to date[3]
GWh lost	1,180 - 1,190	220 - 230	1,400 - 1,420	1,400

During the quarter, we increased the estimated GWh lost for the year as a result of extended planned outages at our Canadian Coal facilities.

(1) Represents amounts spent as of Sept. 30, 2015.

(2) Includes expected hydro life extension costs of $18 million and actual amounts spent to date of $14 million, respectively. During the quarter, we increased the expected hydro life extension costs due to additional costs incurred as a result of delays occurring from equipment installation issues.

(3) As of Sept. 30, 2015.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, dividends reinvested, sale of economic interests in assets or transfers to TransAlta Renewables, and capital markets. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment due to the highly contracted nature of our cash flows, our financial position, and the amount of capital available to us under existing committed credit facilities.

CURRENT ACCOUNTING CHANGES

Operating and Reportable Segments

In January 2015, we completed changes to our internal reporting to systematize allocations of certain costs to each fuel type within our Generation Segment. This permitted internal reports regularly provided to the chief operating decision maker to be presented at the disaggregated fuel type level. Accordingly, commencing with first quarter 2015 reporting, we consider the following distinct fuel types as reportable segments: Canadian Coal, U.S. Coal, Gas, Wind, and Hydro. Previously, these were collectively reported as the Generation Segment. Comparative results for the second quarter 2014 have been restated to align with the re-segmentation: general expenditures of the Generation Segment were allocated to each fuel type segment based on estimated relative benefit derived from those expenditures and for the three and nine months ended Sept. 30, 2015, $5 million and $9 million, respectively, in expenditures associated with certain functions that were determined to benefit the broader organization were reassigned to the Corporate Segment from the Canadian Coal, Gas, Wind, and Hydro Segments. No changes arose in respect of our Energy Marketing Segment.

Management has exercised judgment in aggregating our Canadian gas and Australian gas operating segments together into a single reportable segment, Gas. The operating segments were determined to share the following similar economic characteristics: nature of revenue sources, level of contractedness, and customer assumption of fuel and regulatory compliance costs. In addition, the Canadian gas and Australian gas operating segments share substantial similarity in products (energy), processes (gas turbines), customers (industrial and regional utilities) and distribution methods (connection to grid or behind-the-fence generation).

Change in Estimates - Useful Lives

During the first quarter of 2015, our subsidiary TA Cogen executed a new 15-year power supply contract with Ontario's IESO for the Windsor facility, which is effective Dec. 1, 2016. Accordingly, the useful life of the Windsor facility was extended prospectively to Nov. 30, 2031. As a result, depreciation expense for the three and nine months ended Sept. 30, 2015 decreased by $2 million and $5 million, respectively, and the full year 2015 depreciation expense is expected to be lower by $8 million.

FUTURE ACCOUNTING CHANGES

Accounting standards that have been previously issued by the International Accounting Standards Board ("IASB") but are not yet effective, and which we have not yet applied include IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers*. Refer to the Future Accounting Changes section of our 2014 Annual MD&A for information regarding the requirements of IFRS 9 and IFRS 15.

In September 2015, the IASB issued an amendment to IFRS 15 to defer the Jan. 1, 2017 effective date by one year. Accordingly, both IFRS 9 and IFRS 15 are effective for annual periods beginning on or after Jan. 1, 2018. Early application is permitted for both.

We continue to assess the impact of adopting these standards on the consolidated financial statements.

SELECTED QUARTERLY INFORMATION

	Q4 2014	Q1 2015	Q2 2015	**Q3 2015**
Revenue	718	593	438	**641**
Comparable EBITDA	301	275	183	**219**
Comparable FFO	225	211	160	**126**
Net earnings (loss) attributable to common shareholders	148	7	(131)	**154**
Comparable net earnings (loss) attributable to common shareholders	46	26	(44)	**(33)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.54	0.03	(0.47)	**0.55**
Comparable net earnings (loss) per share, basic and diluted	0.17	0.09	(0.16)	**(0.12)**
	Q4 2013	Q1 2014	Q2 2014	Q3 2014
Revenue	587	775	491	639
Comparable EBITDA	242	310	213	212
Comparable FFO	179	238	154	145
Net earnings (loss) attributable to common shareholders	(66)	49	(50)	(6)
Comparable net earnings (loss) attributable to common shareholders	1	47	(12)	(13)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.25)	0.18	(0.18)	(0.03)
Comparable net earnings (loss) per share, basic and diluted	0.00	0.17	(0.04)	(0.05)

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 is generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate. In 2014, Canadian Coal improved its operational performance, with the third and fourth quarters also including reductions in coal costs. Some of these gains were offset by a downward trend in Alberta prices, continuing during the fourth quarter of 2013 and into the first quarter of 2015. Market volatility can also impact quarterly contributions from our Energy Marketing Segment, as the first quarter of 2014 benefitted from exceptional weather conditions in northeastern North America, with the subsequent two quarters seeing muted volatility and reduced contribution from the Segment. Following public offerings of TransAlta Renewables Common Shares in the second quarter of 2014 and 2015, an increasing portion of earnings is attributable to non-controlling interests.

Revenue is 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 fourth quarter of 2013, in the second quarter of 2014, and in the first half of 2015, and significantly increased in value over the second half of 2014 and in the third quarter of 2015.

Net earnings attributable to common shareholders have also been impacted by the following 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 first quarter of 2015 and a recovery in the third quarter of 2015;
- change in income tax rates in Alberta and deferred income tax impacts of the Transaction in the second quarter of 2015;
- loss associated with the California claim, in the fourth quarter of 2013.

Amounts per share reflect these fluctuations, with between approximately one to two million shares issued in each quarter over the last eight quarters.

DISCLOSURE CONTROLS AND PROCEDURES

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934, as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report 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 Sept. 30, 2015, 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

(in millions of Canadian dollars except per share amounts)

Unaudited	**3 months ended Sept. 30** **2015**	2014	**9 months ended Sept. 30** **2015**	2014
Revenues	**641**	639	**1,672**	1,905
Fuel and purchased power	**299**	277	**736**	824
Gross margin	**342**	362	**936**	1,081
Operations, maintenance, and administration	**130**	138	**383**	404
Depreciation and amortization	**139**	135	**409**	402
Asset impairment reversal	**-**	(1)	**(1)**	(1)
Restructuring *(Note 3)*	**11**	-	**18**	-
Taxes, other than income taxes	**6**	7	**21**	21
Net other operating losses *(Note 4)*	**54**	-	**54**	3
Operating income	**2**	83	**52**	252
Finance lease income	**15**	12	**41**	36
Net interest expense *(Note 5)*	**(63)**	(64)	**(182)**	(192)
Foreign exchange gains (losses)	**2**	-	**1**	(7)
Gain on sale of assets *(Note 3)*	**263**	-	**263**	1
Earnings before income taxes	**219**	31	**175**	90
Income tax expense *(Note 6)*	**31**	18	**62**	33
Net earnings	**188**	13	**113**	57
Net earnings attributable to:				
TransAlta shareholders	**166**	3	**65**	21
Non-controlling interests *(Note 7)*	**22**	10	**48**	36
	188	13	**113**	57
Net earnings attributable to TransAlta shareholders	**166**	3	**65**	21
Preferred share dividends *(Note 13)*	**12**	9	**35**	28
Net income (loss) attributable to common shareholders	**154**	(6)	**30**	(7)
Weighted average number of common shares outstanding in the period *(millions)*	**281**	273	**279**	272
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.55**	(0.03)	**0.11**	(0.03)

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2015**	2014	**2015**	2014
Net earnings	**188**	13	**113**	57
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**2**	3	**4**	(8)
Gains on derivatives designated as cash flow hedges, net of tax(2)	**3**	-	**5**	-
Total items that will not be reclassified subsequently to net earnings	**5**	3	**9**	(8)
Gains on translating net assets of foreign operations	**94**	25	**168**	45
Reclassification of translation gains on net assets of divested foreign operations	-	-	-	(6)
Losses on financial instruments designated as hedges of foreign operations, net of tax(3)	**(52)**	(19)	**(93)**	(37)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax(4)	-	-	-	7
Gains on derivatives designated as cash flow hedges, net of tax(5)	**225**	111	**316**	100
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(6)	**(91)**	(49)	**(145)**	(27)
Total items that will be reclassified subsequently to net earnings	**176**	68	**246**	82
Other comprehensive income	**181**	71	**255**	74
Total comprehensive income	**369**	84	**368**	131
Total comprehensive income attributable to:				
TransAlta shareholders	**347**	73	**312**	88
Non-controlling interests *(Note 7)*	**22**	11	**56**	43
	369	84	**368**	131

(1) Net of income tax expense of 1 and nil for the three and nine months ended Sept. 30, 2015 (2014 - 1 expense and 3 recovery), respectively.

(2) Net of income tax expense of 2 and 2 for the nine months ended Sept. 30, 2015 (2014 - nil).

(3) Net of income tax recovery of 8 and 15 for the three and nine months ended Sept. 30, 2015 (2014 - 2 and 5 recovery), respectively.

(4) Net of income tax recovery of 1 for the nine months ended Sept. 30, 2014.

(5) Net of income tax expense of 80 and 118 for the three and nine months ended Sept. 30, 2015 (2014 - 44 and 37 expense), respectively.

(6) Net of income tax expense of 22 and 35 for the three and nine months ended Sept. 30, 2015 (2014 - 7 and 1 expense), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2015**	Dec. 31, 2014
Cash and cash equivalents	**37**	43
Trade and other receivables *(Note 9)*	**494**	450
Prepaid expenses	**41**	17
Risk management assets *(Notes 8 and 9)*	**264**	273
Inventory *(Note 15)*	**122**	71
	958	854
Long-term portion of finance lease receivables	**770**	403
Property, plant, and equipment *(Note 10)*		
Cost	**12,734**	12,532
Accumulated depreciation	**(5,526)**	(5,294)
	7,208	7,238
Goodwill	**464**	462
Intangible assets	**367**	331
Deferred income tax assets	**80**	45
Risk management assets *(Notes 8 and 9)*	**792**	402
Other assets	**117**	98
Total assets	**10,756**	9,833
Accounts payable and accrued liabilities	**386**	481
Current portion of decommissioning and other provisions	**74**	34
Risk management liabilities *(Notes 8 and 9)*	**164**	128
Income taxes payable	**2**	2
Dividends payable *(Note 12)*	**59**	55
Current portion of long-term debt and finance lease obligations *(Note 11)*	**47**	751
	732	1,451
Credit facilities, long-term debt, and finance lease obligations *(Note 11)*	**4,403**	3,305
Decommissioning and other provisions	**328**	322
Deferred income tax liabilities	**588**	434
Risk management liabilities *(Notes 8 and 9)*	**101**	94
Defined benefit obligation and other long-term liabilities	**346**	349
Equity		
Common shares *(Note 12)*	**3,056**	2,999
Preferred shares *(Note 13)*	**942**	942
Contributed surplus	**9**	9
Deficit	**(905)**	(770)
Accumulated other comprehensive income	**351**	104
Equity attributable to shareholders	**3,453**	3,284
Non-controlling interests *(Note 7)*	**805**	594
Total equity	**4,258**	3,878
Total liabilities and equity	**10,756**	9,833

Commitments and contingencies *(Note 14)*

Subsequent events *(Note 16)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

9 months ended Sept. 30, 2015

Unaudited	**Common shares**	**Preferred shares**	**Contributed surplus**	**Deficit**	**Accumulated other comprehensive income**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec. 31, 2014	2,999	942	9	(770)	104	3,284	594	3,878
Net earnings	-	-	-	65	-	65	48	113
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	75	75	-	75
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	170	170	6	176
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	4	4	-	4
Intercompany available-for-sale investments	-	-	-	-	(2)	(2)	2	-
Total comprehensive income				65	247	312	56	368
Common share dividends	-	-	-	(151)	-	(151)	-	(151)
Preferred share dividends	-	-	-	(35)	-	(35)	-	(35)
Sale of investment in subsidiaries to TransAlta Renewables *(Note 3)*	-	-	-	(14)	-	(14)	229	215
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(74)	(74)
Common shares issued	57	-	-	-	-	57	-	57
Balance, Sept. 30, 2015	**3,056**	**942**	**9**	**(905)**	**351**	**3,453**	**805**	**4,258**

See accompanying notes.

9 months ended Sept. 30, 2014

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive loss	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2013	2,913	781	9	(735)	(62)	2,906	517	3,423
Net earnings	-	-	-	21	-	21	36	57
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	9	9	-	9
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	66	66	7	73
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(8)	(8)	-	(8)
Total comprehensive income				21	67	88	43	131
Common share dividends	-	-	-	(147)	-	(147)	-	(147)
Preferred share dividends	-	-	-	(28)	-	(28)	-	(28)
Secondary offering of TransAlta Renewables Inc. shares	-	-	-	20	-	20	109	129
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(62)	(62)
Common shares issued	66	-	-	-	-	66	-	66
Preferred shares issued	-	162	-	-	-	162	-	162
Balance, Sept. 30, 2014	2,979	943	9	(869)	5	3,067	607	3,674

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 **2015**	2014	9 months ended Sept. 30 **2015**	2014
Operating activities				
Net earnings	**188**	13	**113**	57
Depreciation and amortization	**153**	148	**452**	443
Gain on sale of assets *(Note 3)*	**(263)**	-	**(263)**	(1)
California claim	**-**	-	**-**	(28)
Accretion of provisions	**5**	5	**15**	14
Decommissioning and restoration costs settled	**(7)**	(4)	**(20)**	(11)
Deferred income tax expense *(Note 6)*	**30**	11	**50**	9
Unrealized (gains) losses from risk management activities	**(55)**	(29)	**54**	9
Unrealized foreign exchange (gains) losses	**1**	(4)	**15**	4
Provisions	**67**	(4)	**63**	-
Asset impairment reversals	**-**	(1)	**(1)**	(1)
Other non-cash items	**-**	5	**2**	1
Cash flow from operations before changes in working capital	**119**	140	**480**	496
Change in non-cash operating working capital balances	**81**	76	**(166)**	50
Cash flow from operating activities	**200**	216	**314**	546
Investing activities				
Additions to property, plant, and equipment *(Note 10)*	**(128)**	(144)	**(375)**	(324)
Additions to intangibles	**(7)**	(6)	**(20)**	(19)
Addition to assets held for sale	**-**	-	**-**	(13)
Proceeds on sale of property, plant, and equipment	**1**	2	**3**	2
Proceeds on sale of investments and development projects	**-**	-	**-**	218
Acquisition of renewable energy facilities, net of cash acquired *(Note 3)*	**(52)**	-	**(52)**	-
Realized gains (losses) on financial instruments	**5**	3	**7**	(10)
Net decrease in collateral received from counterparties	**-**	(1)	**-**	(1)
Net increase in collateral paid to counterparties	**-**	-	**-**	4
Decrease in finance lease receivable	**6**	1	**8**	2
Other	**2**	-	**2**	-
Change in non-cash investing working capital balances	**7**	(13)	**2**	4
Cash flow used in investing activities	**(166)**	(158)	**(425)**	(137)
Financing activities				
Net increase (decrease) in borrowings under credit facilities *(Note 11)*	**130**	1	**735**	(532)
Repayment of long-term debt *(Note 11)*	**(120)**	(2)	**(754)**	(207)
Issuance of long-term debt *(Note 11)*	**-**	-	**45**	434
Dividends paid on common shares *(Note 12)*	**(32)**	(29)	**(93)**	(110)
Dividends paid on preferred shares *(Note 13)*	**(12)**	(9)	**(35)**	(28)
Net proceeds on issuance of preferred shares *(Note 13)*	**-**	161	**-**	161
Net proceeds on sale of non-controlling interest in subsidiary *(Note 3)*	**-**	-	**211**	129
Realized gains (losses) on financial instruments	**-**	(6)	**77**	17
Distributions paid to subsidiaries' non-controlling interests *(Note 7)*	**(29)**	(19)	**(70)**	(63)
Decrease in finance lease obligation	**(3)**	(2)	**(10)**	(7)
Change in non-cash financing working capital balances	**(1)**	-	**-**	-
Other	**(1)**	(1)	**(2)**	-
Cash flow from (used in) financing activities	**(68)**	94	**104**	(206)
Cash flow from (used in) operating, investing, and financing activities	**(34)**	152	**(7)**	203
Effect of translation on foreign currency cash	**-**	(1)	**1**	-
Increase (decrease) in cash and cash equivalents	**(34)**	151	**(6)**	203
Cash and cash equivalents, beginning of period	**71**	94	**43**	42
Cash and cash equivalents, end of period	**37**	245	**37**	245
Cash income taxes paid (received)	**5**	(6)	**22**	21
Cash interest paid	**27**	36	**153**	157

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 Board of Directors on Oct. 29, 2015.

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 2015 with respect to operating and reportable segments is described in *Note 2(A).*

2. ACCOUNTING CHANGES

A. Current Accounting Changes

I. Operating and Reportable Segments

In January 2015, the Corporation completed changes to its internal reporting to systematize allocations of certain costs to each fuel type within its Generation Segment. This permitted internal reports regularly provided to the chief operating decision maker to be presented at the disaggregated fuel type level. Accordingly, commencing with first quarter 2015 reporting, the Corporation considers the following distinct fuel types as reportable segments: Canadian Coal, U.S. Coal, Gas, Wind, and Hydro. Previously, these were collectively reported as the Generation Segment. Comparative results for 2014 have been restated to align with the re-segmentation: general expenditures of the Generation Segment were allocated to each fuel type segment based on estimated relative benefit derived from those expenditures. For the three and nine months ended Sept. 30, 2014, $3 million and $12 million, respectively, in expenditures associated with certain functions were determined to benefit the broader organization and were reassigned to the Corporate Segment. No changes arose in respect of the Corporation's Energy Marketing Segment.

Management has exercised judgment in aggregating the Corporation's Canadian gas and Australian gas operating segments together into a single reportable segment, Gas. The operating segments were determined to share the following similar economic characteristics: nature of revenue sources, level of contractedness, and customer assumption of fuel and regulatory compliance costs. In addition, the Canadian gas and Australian gas operating segments share substantial similarity in products (energy), processes (gas turbines), customers (industrial and regional utilities) and distribution methods (connection to grid or behind-the-fence generation). Commencing Sept. 1, 2015, the solar facilities acquired (see *Note 3*) are included in the Wind Segment.

II. Change in Estimates – Useful Lives

During the first quarter, the Corporation's subsidiary TransAlta Cogeneration L.P. ("TA Cogen") executed a new 15-year power supply contract with Ontario's Independent Electricity System Operator for the Windsor facility, which is effective Dec. 1, 2016. Accordingly, the useful life of the Windsor facility was extended prospectively to Nov. 30, 2031. As a result, depreciation expense for the three and nine months ended Sept. 30, 2015 decreased by $2 million and $5 million, respectively. The full year 2015 depreciation expense is expected to be lower by $8 million.

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* and IFRS 15 *Revenue from Contracts with Customers*. Refer to *Note 3* of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 9 and IFRS 15.

In September 2015, the IASB issued an amendment to IFRS 15 to defer the Jan. 1, 2017 effective date by one year. Accordingly, IFRS 9 and IFRS 15 are effective for annual periods beginning on or after Jan. 1, 2018. Early application is permitted for both. The Corporation continues to assess the impact of adopting these standards on its consolidated financial statements.

C. Comparative Figures

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

3. SIGNIFICANT EVENTS

I. Restructured Poplar Creek Contract and Acquisition of Wind Farms

On Sept. 1, 2015, the Corporation and Suncor Energy ("Suncor") closed the restructuring of their arrangement for power generation services at Suncor's oil sands base site near Fort McMurray.

The Corporation's Poplar Creek co-generation facility, which has a maximum capacity of 376 MW, had been built and contracted to provide steam and electricity to Suncor until 2023 and is recorded in the Gas Segment. Under the terms of the new arrangement, Suncor acquired two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. The Corporation retained two gas turbines and heat recovery steam generators ("gas generators"), which are leased to Suncor. Suncor assumed full operational control of the co-generation facility, including responsibility for all capital costs, and has the right to use the full 244 MW capacity of the Corporation's gas generators until Dec. 31, 2030. The Corporation will provide Suncor with centralized monitoring, diagnostics and technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek co-generation facility will transfer to Suncor in 2030. As the new contract was determined to constitute a finance lease, the full carrying amounts of the facility were derecognized.

As part of the transaction, the Corporation acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta.

The following table outlines the preliminary impacts of the transaction, including assets and liabilities disposed of and the fair value of assets acquired and liabilities assumed:

Assets(1)	
Finance lease receivable(2)	372
Property, Plant, and Equipment	104
Intangibles	37
Net working capital(3)	2
Total assets acquired	**515**
Liabilities(1)	
Decomissioning and restoration provision	3
Net assets acquired	**512**
Consideration transferred	
Property, Plant, and Equipment	245
Net working capital(3)	14
Cash(3)	1
Decommissioning and restoration provision	(11)
Carrying amount of transferred net assets	**249**
Gain recognized	**263**

(1) The Corporation's 51 per cent interest in the Wintering Hills facility is accounted for as a joint operation.

(2) Future payments under the finance lease are comprised of \$16 million during the fourth quarter of 2015, \$57 million annually from 2016 to 2018, and \$20 million annually from 2019 to 2030. Future payments have been discounted at a rate of 2.68%, based on comparative yield on borrowings of the counterparty with equivalent maturities.

(3) The Corporation expects to finalize net working capital reconciliations with the transferor during the fourth quarter of 2015.

The acquired wind farms' contribution to the Corporation's revenue and operating income since the date of acquisition has been nominal. Had the acquisition taken place at the beginning of the year, the wind farms would have contributed \$6 million to revenues and reduced \$2 million to earnings before tax of the Corporation.

II. U.S. Solar Acquisition

On Sept. 1, 2015, the Corporation closed the acquisition of 100 per cent of the membership interests of RC Solar LLC for cash consideration of $55 million. The assets acquired include 21 MW of fully contracted solar projects located in Massachusetts, which are contracted under long-term power purchase agreements ranging from 20 to 30 years, and are qualified under phase one of the Massachusetts Solar Renewable Energy Credit program ("SREC-I").

At the acquisition date, the preliminary fair values of the identifiable assets and liabilities of RC Solar LLC were as follows:

Assets	
Property, Plant, and Equipment	107
Inventory (SREC-I)	10
Cash	4
Total assets acquired	121
Liabilities	
Non-recourse debt	55
Deferred tax liabilities[(1)]	10
Other net working capital[(2)]	1
Total liabilities assumed	66
Total consideration transferred[(2)]	**55**

(1) The Corporation has recognized a corresponding deferred tax recovery in the Condensed Consolidated Statement of Earnings at the date of acquisition, representing deductible temporary differences now expected to be recovered.

(2) The Corporation expects to finalize net working capital reconciliations with the seller during the fourth quarter of 2015.

The acquired assets' contribution to the Corporation's revenue and operating income since the date of acquisition has been nominal. Had the acquisition taken place at the beginning of the year, the assets would have contributed $4 million to revenues and $1 million to earnings before tax of the Corporation.

The acquisition of the 50 MW wind facility previously announced as part of the transaction closed on Oct. 1, 2015 (see *Note 16*).

III. Sale of Economic Interest to TransAlta Renewables Inc.

On May 7, 2015, the Corporation closed the previously announced acquisition by TransAlta Renewables Inc. ("TransAlta Renewables") of an economic interest based on the cash flows of the Corporation's Australian assets (the "Transaction"). The Corporation's Australian assets consist of 575 megawatt ("MW") of power generation from six operating assets and the South Hedland project currently under construction, as well as the recently commissioned 270 kilometre gas pipeline (collectively, the "Portfolio"). TransAlta Renewables' investment consists of the acquisition of securities that, in aggregate, provide an economic interest based on cash flows of the Australian assets broadly equal to the underlying net distributable profits. The combined value of the Transaction was $1.78 billion. The Corporation continues to own, manage and operate the Australian assets.

With the closing of the Transaction, TransAlta Renewables paid the Corporation $211 million as well as approximately $1,067 million through a combination of common shares and Class B shares of TransAlta Renewables, increasing its ownership from 70 per cent to 76 per cent. The Class B shares provide voting rights equivalent to the common shares, are non-dividend paying, and will convert into common shares once the South Hedland project is completed and commissioned.

The number of common shares that the Corporation will receive on the conversion of the Class B shares will be adjusted to reflect the actual amount funded by TransAlta Renewables for the construction and commissioning of the South Hedland project relative to target costs of $491 million.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 Common Shares at a price of $12.65 per share. The offering closed in two parts on April 15 and 23, 2015. TransAlta Renewables shareholder approval was received on May 7, 2015. TransAlta Renewables received approximately $226 million in gross proceeds, and in total, incurred $10 million in share issue costs, net of $4 million of income tax recovery. Proceeds to equity were further reduced by dividend equivalent payments of $1 million.

IV. Restructuring

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at its Canadian Coal power generation operations, resulting in the elimination of positions. On Sept. 29, 2015, the Corporation further reduced its overhead costs by eliminating positions primarily at its corporate head office in Calgary.

4. NET OTHER OPERATING LOSSES

A. Settlement with the Market Surveillance Administrator

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the Alberta Utilities Commission (the "AUC") alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. The Corporation denied the MSA's allegations. An oral hearing took place before the AUC in December 2014. A written argument was filed in February 2015. In May 2015, further submissions were filed on a recent Supreme Court of Canada decision relevant to expert evidence. On July 27, 2015, the AUC issued a decision finding, among other things, that (i) the Corporation's actions in relation to four outage events at its coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated Power Purchase Arrangement buyers and manipulated market prices away from a competitive market outcome and (ii) the Corporation breached applicable legislation by allowing one of its employees to trade while in possession of non-public outage records. The AUC also found that the MSA did not prove, on the balance of probabilities, that the Corporation breached applicable legislation on the basis that its compliance policies, practices and oversight thereof, were inadequate and deficient. This AUC decision marked the end of the first phase of the proceedings. TransAlta filed for leave to appeal the AUC decision with the Alberta Court of Appeal in August 2015. The second phase of the AUC proceedings is to consider what penalty the AUC might impose against the Corporation. On Sept. 30, 2015, TransAlta and the MSA reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which is in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the consent order, the Corporation will pay a total amount of $56 million including approximately $27 million as a repayment of economic benefit, $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million will be paid 30 days after the approval date, and the $25 million administrative penalty will be paid one year after this first payment. As a result of the approval, the Corporation will be discontinuing the appeal of the AUC's decision.

The Corporation has accrued the full $56 million as at Sept. 30, 2015.

B. Insurance Recoveries

During the third quarter, the Corporation received $2 million in insurance proceeds relating to claims for repair costs on one of the Corporation's Canadian Coal facilities.

5. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Interest on debt	**57**	60	**170**	179
Capitalized interest	**(1)**	(1)	**(6)**	(1)
Interest on finance lease obligations	**2**	-	**3**	-
Accretion of provisions	**5**	5	**15**	14
Net interest expense	**63**	64	**182**	192

6. INCOME TAXES

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Current income tax expense	**5**	7	**17**	24
Adjustments in respect of current income tax of prior periods	**(4)**	-	**(5)**	-
Adjustments in respect of deferred income tax of prior periods(1)	**5**	-	**3**	2
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**69**	(2)	**35**	(19)
Deferred income tax expense related to temporary difference on investment in subsidiary(2)	**-**	-	**48**	-
Deferred income tax expense resulting from changes in tax rates or laws(3)	**-**	-	**20**	-
Deferred tax benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period, used to reduce deferred income tax expense	**-**	-	**-**	(37)
Deferred income tax expense (recovery) arising from the writedown of deferred income tax assets(1)	**(44)**	13	**(56)**	63
Income tax expense	**31**	18	**62**	33

Presented in the Condensed Consolidated Statements of Earnings as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Current income tax expense	**1**	7	**12**	24
Deferred income tax expense	**30**	11	**50**	9
Income tax expense	**31**	18	**62**	33

(1) During the three and nine months ended Sept. 30, 2015, the Corporation reversed a previous writedown of deferred income tax assets of $51 million (Sept. 30, 2014 - $13 million writedown) and $63 million (Sept. 30, 2014 - $27 million writedown), respectively. Of which, $6 million and $6 million, during the three and nine months ended respectively, has been applied to offset an adjustment in respect of deferred income tax of prior periods. The deferred income tax assets relate mainly 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 three and nine month months ended Sept. 30, 2015 has given rise to a taxable temporary difference which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

(2) In order to give effect to the Transaction with TransAlta Renewables, a reorganization of certain TransAlta companies was completed. The reorganization resulted in the recognition in the first and second quarter of 2015 of $8 million and $40 million deferred tax liability, respectively, 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.

(3) During the second quarter of 2015, the Government of Alberta substantively enacted legislation to increase its provincial corporate income tax rate to 12 per cent from 10 per cent, effective July 1, 2015, resulting in a net increase in the Corporation's deferred income tax liability of $18 million. Of which, $20 million is recorded in the Condensed Consolidated Statement of Earnings with an offsetting $2 million deferred tax recovery recorded in the Condensed Statement of Other Comprehensive Income.

7. NON-CONTROLLING INTERESTS

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

I. TA Cogen

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Revenues	**70**	71	**214**	228
Net earnings	**12**	16	**44**	54
Total comprehensive income	**16**	17	**56**	68
Amounts attributable to the non-controlling interest:				
Net earnings	**6**	9	**22**	28
Total comprehensive income	**8**	10	**28**	35
Distributions paid to the non-controlling interest	**17**	12	**41**	43

As at	**Sept. 30, 2015**	Dec. 31, 2014
Current assets	**65**	58
Long-term assets	**565**	588
Current liabilities	**(70)**	(64)
Long-term liabilities	**(63)**	(59)
Total equity	**(497)**	(523)
Equity attributable to the non-controlling interest	**(246)**	(260)
Non-controlling interest share (per cent)	**49.99**	49.99

II. TransAlta Renewables

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

As a result of the Transaction (Note 3), the Corporation's share of ownership and voting rights increased from 70.3 per cent to 76.1 per cent on May 7, 2015. As the Class B Shares issued to the Corporation in the Transaction 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. Accordingly, the Corporation's equity participation in TransAlta Renewables increased by a smaller proportion from 70.3 per cent to 72.8 per cent following the transaction.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2015	2014	**2015**	2014
Revenues	**41**	43	**161**	161
Net earnings	**61**	1	**90**	29
Total comprehensive income	**53**	1	**97**	29
Amounts attributable to the non-controlling interests:				
Net earnings	**16**	1	**26**	8
Total comprehensive income	**14**	1	**28**	8
Distributions paid to non-controlling interests	**12**	7	**29**	20

As at	**Sept. 30, 2015**	Dec. 31, 2014
Current assets	**60**	61
Long-term assets	**3,187**	1,903
Current liabilities	**(339)**	(241)
Long-term liabilities	**(948)**	(682)
Total equity	**(1,960)**	(1,041)
Equity attributable to non-controlling interests	**(559)**	(334)
Non-controlling interests share (per cent)	**27.2**	29.7

8. FINANCIAL INSTRUMENTS

A. Financial Assets and Liabilities - Measurement

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

B. Fair Value of Financial Instruments

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

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

a. Level I

Fair values are determined using inputs that are 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 asset or liability that are not readily observable.

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

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

The Corporation has a Commodity Exposure Management Policy (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.

	Sept. 30, 2015		Dec. 31, 2014	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - U.S.	**824**	**+109** **-137**	511	+76 -92
Long-term power sales - Alberta	**(14)**	**+14** **-7**	(13)	+13 -8
Unit contingent power purchases	**(49)**	**+8** **-8**	(53)	+9 -8
Eastern market structured deals	**21**	**+6** **-7**	2	+1 -1
Others	**(6)**	**+3** **-4**	(4)	+2 -4

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: 180 MW through Nov. 30, 2015, 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 2020, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views) and market indications. Forward power price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2015 are US$36 - US$45 (Dec. 31, 2014 - US$41 - US$50).

The contract is denominated in US dollars. With the continued strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2014 to Sept. 30, 2015, the base fair value and the sensitivity value have increased by approximately $107 million and $18 million, respectively, as a result of the currency movement. As the contract is reported at present value, downward movements in the US yield curve have also increased the base fair value and sensitivity values.

ii. Long-term power sales - 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 2020, 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 experts in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2015 are $87 - $98 (Dec. 31, 2014 - $91 - $99).

iii. Unit contingent power purchase agreements

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 Sept. 30, 2015 are (0.4) per cent to 2.8 per cent (Dec. 31, 2014 - 0.3 per cent to 1.5 per cent) and 0 per cent to 9 per cent (Dec. 31, 2014 - 0 per cent to 10 per cent), respectively.

iv. Eastern market structured deals

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

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Sept. 30, 2015 are 75 per cent to 150 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 Sept. 30, 2015 are 18 per cent to 64 per cent and 36 per cent to 80 per cent, respectively.

II. Commodity Risk Management Assets and Liabilities

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

The following table summarizes the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2015 and 2014, 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, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	**-**	**(20)**	**316**	**-**	**58**	**(35)**	**-**	**38**	**281**
Market price changes on new contracts	**-**	**(7)**	**-**	**-**	**25**	**(25)**	**-**	**18**	**(25)**
Contracts settled	**-**	**21**	**(19)**	**-**	**(136)**	**63**	**-**	**(115)**	**44**
Net risk management assets (liabilities) at Sept. 30, 2015	**-**	**(65)**	**611**	**-**	**127**	**(94)**	**-**	**62**	**517**
Additional Level III information:									
Gains recognized in OCI			**316**			**-**			**316**
Total gains (losses) included in earnings before income taxes			**19**			**(60)**			**(41)**
Unrealized gains included in earnings before income taxes relating to net liabilities held at Sept. 30, 2015			**-**			**3**			**3**

	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, 2013	-	(66)	55	-	14	11	-	(52)	66
Changes attributable to:									
Market price changes on existing contracts	-	(14)	113	-	(5)	16	-	(19)	129
Market price changes on new contracts	-	(1)	-	-	(12)	17	-	(13)	17
Contracts settled	-	14	(1)	-	18	(41)	-	32	(42)
Net risk management assets (liabilities) at Sept. 30, 2014	-	(67)	167	-	15	3	-	(52)	170
Additional Level III information:									
Gains recognized in OCI			113			-			113
Total gains included in earnings before income taxes			1			33			34
Unrealized losses included in earnings before income taxes relating to net assets held at Sept. 30, 2014			-			(8)			(8)

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2015 are primarily attributable to the following factors:

- maturities and increases in value related to market movements for power contracts in the Pacific Northwest (level II non-hedge);
- 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.

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 $212 million as at Sept. 30, 2015 (Dec. 31, 2014 - $115 million net asset) are classified as Level II fair value measurements. The significant changes in other risk management assets (liabilities) during the nine months ended Sept. 30, 2015 are primarily attributable to the strengthening 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] - Sept. 30, 2015	**-**	**4,313**	**-**	**4,313**	**4,299**
Long-term debt[1] - Dec. 31, 2014	-	4,091	-	4,091	3,918

(1) Includes current portion and excludes $73 million (Dec. 31, 2014 - $64 million) of debt measured and carried at fair value.

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

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

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to *Note 8(B)* for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Condensed Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2015	2014	**2015**	2014
Unamortized net gain at beginning of period	**189**	165	**188**	160
New inception gains	**7**	7	**24**	16
Change in foreign exchange rates	**13**	8	**24**	8
Amortization recorded in net earnings during the period	**(3)**	(2)	**(30)**	(6)
Unamortized net gain at end of period	**206**	178	**206**	178

9. RISK MANAGEMENT ACTIVITIES

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and liabilities are as follows:

As at Sept. 30, 2015	**Net investment hedges**	**Cash flow hedges**	**Fair value hedges**	**Not designated as a hedge**	**Total**
Commodity risk management					
Current	**-**	**13**	**-**	**58**	**71**
Long-term	**-**	**533**	**-**	**(25)**	**508**
Net commodity risk management assets	**-**	**546**	**-**	**33**	**579**
Other					
Current	**(1)**	**28**	**-**	**2**	**29**
Long-term	**-**	**178**	**6**	**(1)**	**183**
Net other risk management assets (liabilities)	**(1)**	**206**	**6**	**1**	**212**
Total net risk management assets (liabilities)	**(1)**	**752**	**6**	**34**	**791**

As at Dec. 31, 2014

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	(2)	-	93	91
Long-term	-	257	-	(10)	247
Net commodity risk management assets	-	255	-	83	338
Other					
Current	-	56	-	(2)	54
Long-term	-	55	6	-	61
Net other risk management assets (liabilities)	-	111	6	(2)	115
Total net risk management assets	-	366	6	81	453

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 Sept. 30, 2015 associated with the Corporation's proprietary trading activities was $3 million (Dec. 31, 2014 - $5 million).

b. Commodity Price Risk – Generating Business

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 Sept. 30, 2015 associated with the Corporation's commodity derivative instruments used in these hedging activities was $21 million (Dec. 31, 2014 - $27 million). VaR at Sept. 30, 2015 associated with positions and economic hedges that do not meet hedge accounting requirements was $3 million (Dec. 31, 2014 - $7 million).

II. Currency Rate Risk

As part of the Transaction described in *Note 3*, the Corporation has entered into foreign exchange hedging contracts with TransAlta Renewables to mitigate the risks to TransAlta Renewables shareholders of adverse changes in AUD in respect of AUD$392 million remaining investments to fund the South Hedland project. In addition, the Corporation has agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in USD and AUD in respect of cash flows from the Australian assets in relation to the Canadian dollar for the first five years from the time of the Transaction. The financial effects of these contracts and agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation has entered into foreign currency hedges with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years. Hedge accounting is not applied to these foreign currency hedges and accordingly the gain on the contracts, amounting to $1 million and nil, has been recognized as a foreign exchange gain in the Condensed Consolidated Statement of Earnings during the three and nine months ended Sept. 30, 2015, respectively.

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 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 Sept. 30, 2015:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total Amount**
Trade and other receivables[1]	91	9	**100**	**494**
Long term finance lease receivables[2]	41	59	**100**	**770**
Risk management assets[1]	100	-	**100**	**1,056**
Total				**2,320**

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

(2) Includes a balance of $431 million attributable to one non-investment grade customer. Risk of significant loss arising from this counterparty has been assessed as low, considering the counterparty's financial position 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 counterparty for commodity trading operations and hedging, including the fair value of open trading positions, net of any collateral held, at Sept. 30, 2015 was $30 million (Dec. 31, 2014 - $29 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.

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

	2015	2016	2017	2018	2019	2020 and thereafter	Total
Accounts payable and accrued liabilities	386	-	-	-	-	-	386
Long-term debt[(1)]	5	35	546	883	1,241	1,668	4,378
Commodity risk management (assets) liabilities	(21)	(44)	(42)	(47)	(61)	(364)	(579)
Other risk management (assets) liabilities	(15)	(15)	(108)	(74)	-	-	(212)
Interest on long-term debt[(2)]	53	207	200	160	124	807	1,551
Dividends payable	59	-	-	-	-	-	59
Total	**467**	**183**	**596**	**922**	**1,304**	**2,111**	**5,583**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature between 2016 and 2018.

(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 to fall below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Sept. 30, 2015, the Corporation had posted collateral of $96 million (Dec. 31, 2014 - $73 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $143 million (Dec. 31, 2014 - $86 million) of collateral to its counterparties.

10. PROPERTY, PLANT, AND EQUIPMENT

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

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[(1)]	Total
As at Dec. 31, 2014	82	2,862	876	2,169	615	341	293	7,238
Additions	**1**	**-**	**6**	**-**	**-**	**365**	**3**	**375**
Acquisitions *(Note 3)*	**-**	**-**	**-**	**211**	**-**	**-**	**-**	**211**
Additions - finance lease	**-**	**-**	**-**	**-**	**7**	**-**	**-**	**7**
Disposals *(Note 3)*	**-**	**-**	**(244)**	**-**	**-**	**-**	**(1)**	**(245)**
Asset impairment reversals	**-**	**-**	**1**	**-**	**-**	**-**	**-**	**1**
Depreciation	**-**	**(207)**	**(68)**	**(74)**	**(44)**	**-**	**(9)**	**(402)**
Revisions and additions to decommissioning and restoration costs	**-**	**(17)**	**(3)**	**(8)**	**(2)**	**-**	**-**	**(30)**
Retirement of assets	**-**	**(9)**	**(6)**	**(4)**	**(2)**	**-**	**(1)**	**(22)**
Change in foreign exchange rates	**1**	**53**	**(3)**	**14**	**8**	**(4)**	**6**	**75**
Transfers	**10**	**166**	**122**	**28**	**33**	**(346)**	**(13)**	**-**
As at Sept. 30, 2015	**94**	**2,848**	**681**	**2,336**	**615**	**356**	**278**	**7,208**

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

11. CREDIT FACILITIES, LONG-TERM DEBT, AND FINANCE LEASE OBLIGATIONS

A. Debt and Letters of Credit

The amounts outstanding are as follows:

As at	**Sept. 30, 2015**			Dec. 31, 2014		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**832**	**832**	**2.7%**	96	96	2.8%
Debentures	**1,044**	**1,051**	**6.0%**	1,043	1,051	6.1%
Senior notes[3]	**2,149**	**2,147**	**4.9%**	2,444	2,436	4.9%
Non-recourse[4]	**330**	**331**	**5.3%**	380	383	5.9%
Other	**17**	**17**	**5.9%**	19	19	5.9%
	4,372	**4,378**		3,982	3,985	
Finance lease obligations	**78**			74		
	4,450			4,056		
Less: current portion of long-term debt	**(32)**			(738)		
Less: current portion of finance lease obligations	**(15)**			(13)		
Total current long-term debt and finance lease obligations	**(47)**			(751)		
Total credit facilities, long-term debt, and finance lease obligations	**4,403**			3,305		

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

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

(3) US face value at Sept. 30, 2015 - US$1.6 billion (Dec. 31, 2014 - US$2.1 billion).

(4) Includes US$62 million at Sept. 30, 2015 (Dec. 31, 2014 - US$20 million).

On Jan. 15, 2015, the Corporation's US$500 million 4.75 per cent senior notes matured and were paid out using existing liquidity.

On Feb. 11, 2015, the Corporation and its partner issued non-recourse bonds secured by their jointly owned Pingston facility. The Corporation's share of gross proceeds was $45 million. The non-recourse bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million non-recourse debenture bearing interest at 5.28 per cent related to the Pingston facility.

On Sept. 1, 2015, the Corporation's $120 million 5.33 per cent non-recourse debentures matured and were paid out using existing liquidity. The Corporation also closed the acquisition of solar assets (see *Note 3*) and assumed approximately US$42 million of non-recourse variable rate debt, of which approximately US$32 million is hedged to a fixed rate of 4.698 per cent.

As at Sept. 30, 2015, TransAlta had a total of $2.1 billion (Dec. 31, 2014 - $2.1 billion) of committed credit facilities and bilateral credit facilities, of which $0.9 billion (Dec. 31, 2014 - $1.6 billion) was available, subject to customary borrowing conditions.

On Oct. 1, 2015, the Corporation issued non-recourse debentures, as described in *Note 16*.

The total outstanding letters of credit as at Sept. 30, 2015 was $449 million (Dec. 31, 2014 - $396 million) with no (Dec. 31, 2014 - nil) amounts exercised by third parties under these arrangements. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business.

The Corporation's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Sept. 30, 2015, the Corporation was in compliance with all debt covenants.

B. Restrictions

Non-recourse debentures of $229 million (Dec. 31, 2014 - $344 million) issued by the Corporation's Canadian Hydro Developers, Inc. ("CHD") subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewable assets or in the repayment of the non-recourse debentures.

Other non-recourse debt of $101 million (Dec. 31, 2014 - $35 million) is secured by certain renewable generation facilities and subject to customary financing restrictions which restrict the Corporation's ability to access funds generated by the facilities' operations.

12. COMMON SHARES

A. Issued and Outstanding

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

	3 months ended Sept. 30				**9 months ended Sept. 30**			
	2015		2014		**2015**		2014	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount	**Common shares** *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**278.7**	**3,039**	271.8	2,962	**275.0**	**3,001**	268.2	2,916
and optional common share purchase plan	**1.9**	**19**	1.6	19	**5.6**	**57**	5.2	65
	280.6	**3,058**	273.4	2,981	**280.6**	**3,058**	273.4	2,981
Amounts receivable under Employee Share Purchase Plan	**-**	**(2)**	-	(2)	**-**	**(2)**	-	(2)
Issued and outstanding, end of period	**280.6**	**3,056**	273.4	2,979	**280.6**	**3,056**	273.4	2,979

B. Dividends

On July 21, 2015, the Corporation declared a quarterly dividend of $0.18 per common share, payable on Oct. 1, 2015. On payment, 3.4 million common shares were issued for dividends reinvested.

On Oct. 29, 2015, the Corporation declared a quarterly dividend of $0.18 per common share, payable on Jan. 1, 2016.

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

13. PREFERRED SHARES

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares. The holders are entitled to receive cumulative fixed quarterly cash dividends at specified rates, as approved by the Board. Refer to *Note 25* of the Corporation's most recent annual consolidated financial statements for more information regarding the terms of the preferred shares.

At Sept. 30, 2015 and Dec. 31, 2014, the Corporation had 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred shares issued and outstanding.

B. Dividends

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

		3 months ended Sept. 30		9 months ended Sept. 30	
		2015	2014	**2015**	2014
Series	Quarterly amounts per share	**Total**	Total	**Total**	Total
A	0.2875	**3**	3	**10**	10
C	0.2875	**4**	4	**10**	10
E	0.3125	**2**	2	**8**	8
G	0.33125	**3**	-	**7**	-
Total for the period		**12**	9	**35**	28

On Oct. 29, 2015, the Corporation declared 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 Dec. 31, 2015.

14. COMMITMENTS AND CONTINGENCIES

A. TransAlta Energy Bill Commitment

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining 10 year life of the Centralia coal plant to support energy effiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Sept. 30, 2015, the Corporation has funded US$14 million of the commitment which is recognized as an Other asset in the Condensed Consolidated Statements of Financial Position.

B. Contingencies

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

15. SEGMENT DISCLOSURES

A. Reported Segment Earnings (Loss)

3 months ended Sept. 30, 2015	**Canadian Coal**	**U.S. Coal**	**Gas**	**Wind[(1)]**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**253**	**172**	**140**	**38**	**28**	**10**	**-**	**641**
Fuel and purchased power	**116**	**121**	**57**	**3**	**2**	**-**	**-**	**299**
Gross margin	**137**	**51**	**83**	**35**	**26**	**10**	**-**	**342**
Operations, maintenance, and administration	**51**	**15**	**24**	**11**	**9**	**4**	**16**	**130**
Depreciation and amortization	**62**	**15**	**22**	**26**	**7**	**-**	**7**	**139**
Restructuring provision	**2**	**1**	**1**	**-**	**-**	**3**	**4**	**11**
Taxes, other than income taxes	**3**	**-**	**-**	**1**	**2**	**-**	**-**	**6**
Net other operating (income) loss	**(2)**	**-**	**-**	**-**	**-**	**56**	**-**	**54**
Operating income (loss)	**21**	**20**	**36**	**(3)**	**8**	**(53)**	**(27)**	**2**
Finance lease income	**-**	**-**	**15**	**-**	**-**	**-**	**-**	**15**
Gain on sale of assets	**-**	**-**	**263**	**-**	**-**	**-**	**-**	**263**
Net interest expense								**(63)**
Foreign exchange loss								**2**
Earnings before income taxes								**219**

(1) Includes the results of the acquired Solar facilities commencing Sept. 1, 2015.

3 months ended Sept. 30, 2014 *(Restated - see Note 2)*	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	260	144	149	43	40	3	-	639
Fuel and purchased power	126	84	60	3	4	-	-	277
Gross margin	134	60	89	40	36	3	-	362
Operations, maintenance, and administration	52	11	25	11	13	7	19	138
Depreciation and amortization	59	13	28	22	6	-	7	135
Asset impairment reversal	-	-	(1)	-	-	-	-	(1)
Taxes, other than income taxes	3	1	-	2	-	-	1	7
Operating income (loss)	20	35	37	5	17	(4)	(27)	83
Finance lease income	-	-	12	-	-	-	-	12
Net interest expense								(64)
Earnings before income taxes								31

9 months ended Sept. 30, 2015	**Canadian Coal**	**U.S. Coal**	**Gas**	**Wind[(1)]**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**704**	**246**	**447**	**160**	**91**	**24**	**-**	**1,672**
Fuel and purchased power	**328**	**210**	**183**	**9**	**6**	**-**	**-**	**736**
Gross margin	**376**	**36**	**264**	**151**	**85**	**24**	**-**	**936**
Operations, maintenance, and administration	**148**	**37**	**71**	**35**	**29**	**13**	**50**	**383**
Depreciation and amortization	**178**	**47**	**75**	**70**	**19**	**-**	**20**	**409**
Asset impairment recovery	**-**	**-**	**(1)**	**-**	**-**	**-**	**-**	**(1)**
Restructuring provision	**9**	**1**	**1**	**-**	**-**	**3**	**4**	**18**
Taxes, other than income taxes	**9**	**2**	**2**	**5**	**3**	**-**	**-**	**21**
Net other operating (income) loss	**(2)**	**-**	**-**	**-**	**-**	**56**	**-**	**54**
Operating income (loss)	**34**	**(51)**	**116**	**41**	**34**	**(48)**	**(74)**	**52**
Finance lease income	**-**	**-**	**41**	**-**	**-**	**-**	**-**	**41**
Gain on sale of assets	**-**	**-**	**263**	**-**	**-**	**-**	**-**	**263**
Net interest expense								**(182)**
Foreign exchange loss								**1**
Earnings before income taxes								**175**

(1) Includes the results of the acquired Solar facilities commencing Sept. 1, 2015.

9 months ended Sept. 30, 2014 *(Restated - see Note 2)*	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	750	266	537	172	104	76	-	1,905
Fuel and purchased power	364	176	266	10	8	-	-	824
Gross margin	386	90	271	162	96	76	-	1,081
Operations, maintenance, and administration	148	35	75	34	34	27	51	404
Depreciation and amortization	175	40	83	66	18	-	20	402
Asset impairment reversal	-	-	(1)	-	-	-	-	(1)
Taxes, other than income taxes	9	2	2	5	2	-	1	21
Net other operating (gains) losses	-	-	-	-	(2)	5	-	3
Operating income (loss)	54	13	112	57	44	44	(72)	252
Finance lease income	-	-	36	-	-	-	-	36
Gain on sale of assets								1
Net interest expense								(192)
Foreign exchange loss								(7)
Earnings before income taxes								90

During the three and nine months ended Sept. 30, 2015, the Corporation recorded a $17 million writedown (Sept. 30, 2014 - $6 million writedown) and $19 million writedown (Sept. 30, 2014 - $6 million writedown) of coal inventory 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 Segment for the three and nine months ended Sept. 30, 2015 are $4 million (Sept. 30, 2014 - $4 million) and $14 million (Sept. 30, 2014 - $15 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 and the Condensed Consolidated Statements of Cash Flows is presented below:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2015	2014	**2015**	2014
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**139**	135	**409**	402
Depreciation included in fuel and purchased power	**14**	13	**43**	41
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**153**	148	**452**	443

16. SUBSEQUENT EVENTS

A. U.S. Wind Acquisition

On Oct. 1, 2015, the Corporation closed the previously announced acquisition of 100 per cent of the membership interests of Odin Wind Power LLC, owner of the 50 MW Lakeswind wind facility located in Minnesota for cash consideration of $49 million and the assumption of certain tax equity obligations. The facility is contracted under long-term power purchase agreements until 2034 with high quality counterparties. The Corporation is currently in the process of assessing the fair values of identifiable assets and liabilities of the entity.

B. Ontario Wind Asset Financing

On Oct. 1, 2015, Melancthon Wolfe Wind LP (the “Issuer”), a wholly owned subsidiary of TransAlta Renewables closed a $442 million bond offering, which were secured by a first ranking charge over all assets of the Issuer, the Melancthon and Wolfe Island wind farms. The bonds are amortizing, and bear interest at a rate of 3.834 per cent, payable semi-annually and mature on Dec. 31, 2028.

Net proceeds of the financing will be used to reduce the draw down on the Corporation’s credit facilities.

SUPPLEMENTAL INFORMATION

		Sept. 30, 2015	Dec. 31, 2014
Closing market price (TSX) ($)		**6.20**	10.52
Price range for the last 12 months (TSX) ($)	High	**12.34**	14.94
	Low	**5.63**	9.81
Adjusted net debt to invested capital (%)		**55.4**	56.3
Adjusted net debt to invested capital excluding non-recourse debt(1) (%)		**53.6**	54.1
Adjusted net debt to comparable EBITDA(2) (times)		**4.8**	4.2
Return on equity attributable to common shareholders(2) (%)		**8.2**	6.3
Comparable return on equity attributable to common shareholders(1), (2) (%)		**(0.2)**	3.0
Return on capital employed(2) (%)		**6.2**	5.8
Comparable return on capital employed(1), (2) (%)		**3.9**	5.1
Cash dividends per share(2) ($)		**0.72**	0.83
Earnings coverage(2) (times)		**2.0**	1.7
Dividend payout ratio based on comparable funds from operations(1), (2) (%)		**28.7**	26.4
Dividend yield(2) (%)		**11.6**	7.9
Adjusted comparable FFO to adjusted net debt(2) (%)		**14.8**	16.9
Comparable FFO before interest to adjusted interest coverage(2) (times)		**3.7**	3.8

(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 this calculation, refer to the Non-IFRS Measures section of this MD&A.

(2) Last 12 months.

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/ long-term debt including current portion + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares - cash and cash equivalents

Adjusted net debt to comparable EBITDA = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt - 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

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 = common share dividends / funds from operations - 50 per cent dividends paid on preferred shares

Dividend yield = dividend 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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