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 six months ended June 30, 2013 and 2012, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2012 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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated July 29, 2013. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading, and Corporate. 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 (Loss) 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 (Loss) ("AOCI") in the equity section of the Condensed Consolidated Statements of Financial Position.

HIGHLIGHTS

Second Quarter Highlights

Generation Results

- Comparable gross margins for Generation operations, which does not include finance lease income, were consistent quarter over quarter primarily due to higher margins in Western Canadian hydro, wind, and gas in response to strong market prices; and lower market curtailments offset by lower contract pricing at Centralia Thermal and unfavourable coal pricing. Comparable gross margins were also reduced by unrealized mark-to-market movements.
- Total finance lease income increased $10 million in the quarter due to the new Solomon finance lease.
- Overall availability, including finance leases and equity investments, adjusted for economic dispatching at Centralia, was 81.8 per cent compared to 87.2 per cent in 2012. The decrease in availability is primarily due to higher unplanned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities, primarily driven by the Keephills Unit 1 force majeure outage, partially offset by lower planned outages at the Alberta coal facilities.

- Overall availability, including finance leases and equity investments, was 72.1 per cent compared to 81.6 per cent in 2012.
- Overall production decreased 164 gigawatt hours ("GWh") to 8,110 GWh compared to 2012.
- Comparable Operations, Maintenance, and Administration ("OM&A") costs increased $5 million to $110 million compared to the same period in 2012 due to higher emergent costs, higher routine maintenance costs, and higher costs that are recoverable through PPAs, partially offset by lower compensation costs. This increase is partially offset by savings in OM&A in our other segments.

Energy Trading Results

- Energy Trading gross margins increased $25 million to $14 million quarter over quarter, due to strong trading performance across all markets and prudent management of risk. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by strong trading performance across all markets.

Financial Highlights

- Funds from Operations ("FFO") increased $34 million to $184 million compared to the prior year.
- Comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA") increased $54 million in the quarter to $247 million compared to 2012.
- Comparable earnings were $9 million ($0.03 per share), up from a comparable loss of $23 million ($0.10 per share) in 2012. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by favourable effects of pricing on trading positions held and higher finance lease income due to the new Solomon finance lease.
- Reported net earnings attributable to common shareholders were $15 million ($0.06 net earnings per share), up from net losses attributable to common shareholders of $798 million ($3.52 net loss per share) in 2012. The change is driven by an increase in comparable gross margin of $34 million and the following non-comparable amounts, net of tax:
    - Decrease in asset impairment charges of $360 million
    - Decrease in impact of Sundance Units 1 and 2 arbitration of $184 million
    - Decrease in income tax expense related to writeoff of deferred income tax assets of $169 million
    - Impact of de-designated hedges of $49 million
- On June 26, 2013, we announced the creation of TransAlta Renewables Inc. ("TransAlta Renewables"), an entity which will provide investors with the opportunity to invest directly in a highly contracted portfolio of renewable power generation facilities. The creation of TransAlta Renewables provides us with a focused vehicle for pursuing and funding growth opportunities in the renewable power generation sector.

Year-To-Date Highlights

Generation Results

- Comparable gross margins for Generation operations, which doesn't include finance lease income, decreased $5 million to $712 million year over year, primarily due to lower contract pricing at Centralia Thermal and unfavourable coal pricing; partially offset by lower planned outages at Alberta coal facilities; higher margins in Western Canadian hydro, wind, and gas in response to strong market prices; and lower market curtailments. Comparable gross margins were also reduced by unrealized mark-to-market movements.
- Total finance lease income increased $19 million year over year due to the new Solomon finance lease.
- Overall availability, including finance leases and equity investments, adjusted for economic dispatching at Centralia, was 86.6 per cent compared to 89.5 per cent in 2012. The decrease in availability is primarily due to higher unplanned

outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage, partially offset by lower planned outages at the Alberta coal facilities.

- Overall availability, including finance leases and equity investments, was 81.7 per cent compared to 86.7 per cent in 2012.
- Overall production increased 1,039 GWh to 18,754 GWh compared to 2012.
- OM&A costs are comparable to the same period in 2012.

Energy Trading Results

- Energy Trading gross margins increased $25 million to $31 million period over period, due to strong trading performance across all markets and prudent management of risk. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by strong trading performance across all markets.

Financial Highlights

- FFO increased $37 million to $376 million compared to the prior year.
- Comparable EBITDA increased $68 million to $514 million compared to 2012.
- Comparable earnings were $41 million ($0.16 per share), up from $21 million ($0.09 per share) in 2012. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by favourable effects of pricing on trading positions held, higher finance lease income due to the Solomon finance lease, and OM&A savings in the Corporate Segment.
- Reported net earnings attributable to common shareholders were $4 million ($0.02 net earnings per share), up from net losses attributable to common shareholders of $710 million ($3.14 net loss per share) in 2012. The change is driven by an increase in comparable gross margin of $40 million and the following non-comparable amounts, net of tax:
  - Decrease in asset impairment charges of $360 million
  - Decrease in impact of Sundance Units 1 and 2 arbitration of $184 million
  - Decrease in income tax expense related to writeoff of deferred income tax assets of $169 million
  - Net loss impact of de-designated hedges of $33 million
  - Loss on assumption of pension obligations of $22 million due to the assumption of mining operations at the Highvale Mine and related pension obligations for mine employees

The following table depicts key financial results and statistical operating data:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Availability (%)[1]	**72.1**	81.6	**81.7**	86.7
Adjusted availability (%)[1],[2]	**81.8**	87.2	**86.6**	89.5
Production (GWh)[1]	**8,110**	8,274	**18,754**	17,715
Revenues	**542**	398	**1,082**	1,042
Gross margin[3]	**355**	256	**694**	725
Comparable gross margin[4]	**363**	329	**743**	703
Operating income (loss)[3]	**83**	(396)	**159**	(225)
Comparable operating income[4]	**102**	54	**230**	176
Net earnings (loss) attributable to common shareholders	**15**	(798)	**4**	(710)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.06**	(3.52)	**0.02**	(3.14)
Comparable net earnings (loss) per share[4]	**0.03**	(0.10)	**0.16**	0.09
Comparable EBITDA[4]	**247**	193	**514**	446
Funds from operations[4]	**184**	150	**376**	339
Funds from operations per share[4]	**0.70**	0.66	**1.45**	1.50
Cash flow from operating activities	**92**	78	**348**	261
Free cash flow (deficiency)[4]	**9**	(34)	**85**	(24)
Dividends paid per common share	**0.29**	0.29	**0.58**	0.58

As at	**June 30, 2013**	Dec. 31, 2012
Total assets	**9,456**	9,462
Total long-term liabilities	**5,060**	4,729

AVAILABILITY & PRODUCTION

Availability for the three and six months ended June 30, 2013 decreased compared to the same periods in 2012 primarily due to higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage, and higher planned and unplanned outages at Centralia Thermal, partially offset by lower planned outages at the Alberta coal facilities.

Production for the three months ended June 30, 2013 decreased 164 GWh compared to the same period in 2012 primarily due to higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage, higher planned and unplanned outages at Centralia Thermal, and unfavourable conditions at natural gas-fired facilities, partially offset by lower economic dispatching at Centralia Thermal, higher PPA customer demand, lower planned outages at the Alberta coal facilities, and lower market curtailments.

(1) Availability and production includes all generating assets (generation operations, finance leases, and equity investments).

(2) Adjusted for economic dispatching at Centralia Thermal.

(3) These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of these items.

(4) 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 Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

For the six months ended June 30, 2013, production increased 1,039 GWh compared to the same period in 2012 primarily due to lower economic dispatching at Centralia Thermal, lower planned outages at the Alberta coal facilities, higher PPA customer demand, and lower market curtailments, partially offset by higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage, and higher planned and unplanned outages at Centralia Thermal.

NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings attributable to common shareholders for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30	**6 months ended June 30**
Net loss attributable to common shareholders, 2012	(798)	(710)
Decrease in Generation comparable gross margins	(1)	(5)
Mark-to-market movements and de-designations on hedges - Generation	75	(51)
Increase in Energy Trading gross margins	25	25
Decrease in operations, maintenance, and administration costs	-	13
Decrease in depreciation and amortization expense	8	10
Increase in gain on sale of assets	10	7
Decrease in asset impairment charges	365	365
Decrease in coal inventory writedown	6	26
Increase in finance lease income	10	19
Increase in reversal of restructuring charges	2	2
Decrease (increase) in equity loss	2	(2)
Increase in loss on assumption of pension obligations	-	(29)
Decrease in impact of Sundance Units 1 and 2 arbitration	247	247
Decrease in income tax expense	65	84
Increase in preferred share dividends	(4)	(6)
Other	3	9
Net earnings attributable to common shareholders, 2013	**15**	**4**

Generation comparable gross margins for the three and six months ended June 30, 2013, excluding the impact of mark-to-market movements on de-designations, decreased by $1 million and $5 million, respectively, compared to the same periods in 2012, as there was lower contract pricing at Centralia Thermal, and unfavourable coal pricing; partially offset by higher margins in Western Canadian hydro, wind, and gas in response to strong market prices; lower planned outages at Alberta coal facilities; and lower market curtailments.

Mark-to-market movements increased for the three months ended June 30, 2013 compared to the same period in 2012 due to the recognition of lower mark-to-market gains in 2012 resulting from certain power hedging relationships being deemed ineffective.

Mark-to-market movements decreased for the six months ended June 30, 2013 compared to the same period in 2012 due to the recognition of higher mark-to-market gains in 2012 resulting from certain power hedging relationships being deemed ineffective and released from AOCI to net earnings.

For the three and six months ended June 30, 2013, Energy Trading gross margins increased compared to the same periods in 2012 due to strong trading performance across all markets and prudent management of risk. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by strong trading performance across all markets.

OM&A costs for the six months ended June 30, 2013 decreased compared to the same period in 2012 primarily due to lower compensation costs as a result of organizational restructuring in the fourth quarter of 2012 and a continued focus on costs.

Depreciation and amortization expense for the three and six months ended June 30, 2013 decreased compared to the same periods in 2012 primarily due to a lower depreciable base caused by asset impairments, the change in the economic useful lives of Alberta coal-fired plants resulting from amendments to Canadian federal regulations in 2012, and a decrease in asset retirements, partially offset by an increased asset base through acquiring new assets and the commencement of commercial operations of New Richmond.

The increase in the gain on sale of assets in the three and six months ended June 30, 2013 compared to the same periods in 2012 is due to the sale of land during the second quarter of 2013.

Coal inventory has been written down to its net realizable value at our Centralia plant. The writedown for the three and six months ended June 30, 2013 is lower compared to the same periods in 2012 due to an increase in prices in the Pacific Northwest and a decrease in delivered coal costs.

Finance lease income for the three and six months ended June 30, 2013 increased compared to the same periods in 2012 due to the acquisition of the Solomon Power station. We began receiving lease payments in the fourth quarter of 2012.

Reversal of restructuring charges for the three and six months ended June 30, 2013 increased compared to the same periods in 2012 due to a reduction in our total expected costs.

Equity loss for the three months ended June 30, 2013 decreased compared to the same period in 2012 primarily due to favourable pricing, partially offset by higher unplanned outages at CE Generation, LLC ("CE Gen").

For the six months ended June 30, 2013, equity loss increased compared to the same period in 2012 primarily due to higher planned outages at CE Gen and unfavourable pricing.

Pension obligations for the six months ended June 30, 2013 increased compared to the same period in 2012 due to assuming certain pension obligations during the first quarter related to assuming operating and management control of the Highvale Mine.

For the three and six months ended June 30, 2013, the impact of the Sundance Units 1 and 2 arbitration decreased compared to the same periods in 2012. The impact of the arbitration ruling was recorded during the second quarter of 2012.

Income tax expense for the three and six months ended June 30, 2013 decreased compared to the same periods in 2012 due to the income tax effect on non-comparable items that were recorded during the second quarter of 2012.

The preferred share dividends for the three and six months ended June 30, 2013 increased compared to the same periods in 2012 due to a higher balance of preferred shares outstanding during 2013.

FUNDS FROM OPERATIONS AND FREE CASH FLOW (DEFICIENCY)

FFO for the three and six months ended June 30, 2013 increased $34 million and $37 million, respectively, compared to the same period in 2012 to $184 million and $376 million, respectively, due to higher comparable net earnings, after excluding the impact of Sundance Units 1 and 2 arbitration in 2012.

Free cash flow (deficiency) for the three months ended June 30, 2013 increased $43 million compared to the same period in 2012 due to higher net earnings and lower sustaining capital expenditures, partially offset by higher cash dividends paid.

For the six months ended June 30, 2013, free cash flow (deficiency) increased $109 million compared to the same period in 2012 due to higher net earnings, lower cash dividends paid as a result of increased participation in the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "Plan"), and lower sustaining capital expenditures

SIGNIFICANT EVENTS

Three months ended June 30, 2013

TransAlta Renewables Inc.

On June 26, 2013, we announced the launch and creation of TransAlta Renewables, an entity which will provide investors with the opportunity to invest directly in a highly contracted portfolio of renewable power generation facilities. We will be the sponsor and manager of TransAlta Renewables and will provide TransAlta Renewables with its initial asset base. A preliminary prospectus qualifying the initial public offering of TransAlta Renewables common shares to the public (the "Offering") was filed on June 26, 2013.

We intend to transfer 1,112 net megawatts ("MW") of highly contracted wind and hydro power generation assets to TransAlta Renewables upon completion of the Offering. We will be the primary source of growth of TransAlta Renewables' portfolio of renewable power generation assets, by providing TransAlta Renewables with the opportunity to purchase, or participate in the development of, renewable power generation facilities with stable, long-term, contracted cash flows. The creation of TransAlta Renewables provides us with a focused vehicle for pursuing and funding growth opportunities in the renewable power generation sector. Upon completion of the Offering, we will retain control of and fully consolidate TransAlta Renewables.

Completion of the Offering is subject to, and conditional upon, the receipt of all necessary approvals, including regulatory approvals. The Offering is expected to close in August 2013.

Update on Hydro Facilities Due to Southern Alberta Flooding

As a result of extremely high rainfall in southern Alberta and inflows to our reservoirs, we were required, and continue, to manage the water flow through our hydro systems safely and efficiently under these difficult circumstances. We continue to monitor and adjust the flow of water through our hydro system to accommodate fluctuations in water levels. Several of the hydro facilities we operate in Alberta in the Bow River Basin have been impacted by the flooding events and are currently being inspected and tested to determine the extent of the damage. We continue to assess any financial impacts through the third quarter and believe that we have sufficient insurance coverage for this damage, subject to a $5 million deductible.

City of Riverside

On June 18, 2013, we announced that CalEnergy, LLC ("CalEnergy"), a joint venture with MidAmerican Energy Holdings Company, had executed an 86 MW long-term contract for renewable geothermal power with the City of Riverside which runs from 2016 to 2039. CalEnergy will purchase the power from CE Gen's portfolio of geothermal generating facilities in California's Imperial Valley.

Sundance Units 1 and 2

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of our Sundance facility were shut down due to conditions observed in the boilers at both units. On Feb. 8, 2011, we issued a notice of termination for destruction based on the determination that the units could not be economically restored to service under the terms of the PPA. On July 20, 2012, an arbitration panel concluded that Units 1 and 2 were not to be economically destroyed and required the units to be restored to service. However, the panel affirmed that the event met the criteria of force majeure beginning Nov. 20, 2011 and continuing until such a time as each unit is returned to service. The cost to repair Sundance Units 1 and 2 is estimated at approximately $215 million and are expected to start generating production in the third and fourth quarter of 2013, respectively. The total estimated spend has increased by $25 million due to additional scope of work for balance of plant systems and equipment as well as higher labour costs due to an increase in rates. This work is being performed concurrently with the boiler repairs to prevent the need for a later outage for this work.

We expect an earlier return-to-service date of Aug. 6 for Sundance Unit 1.

Premium Dividend™ Program

On May 8, 2013, we announced that as a result of the current low share price environment, we are suspending the Premium Dividend™ component of the Plan following the payment of the quarterly dividend on July 1, 2013. Our Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remain effective in accordance with their current terms.

Keephills Unit 1

On March 5, 2013, an outage occurred at Unit 1 of our Keephills facility due to a winding failure found in the generator. Upon completion of the initial repair work, further condition testing and analysis identified greater winding degradation requiring a full rewind of the generator. In response to the event, we gave notice of a High Impact Low Probability event and claimed force majeure relief under the PPA. In the event of a force majeure, 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. As a result, we do not expect the outage to have a material financial impact on the Corporation. We are working with the original equipment manufacturer of the generator to safely return the Unit to service, which is expected to be October 2013.

Six months ended June 30, 2013

New Richmond

On March 13, 2013, our 68 MW New Richmond wind farm began commercial operations. The total cost of the project remains at approximately $212 million.

SunHills Mining Limited Partnership

Effective Jan. 17, 2013, we assumed, through our wholly owned SunHills Mining Limited Partnership ("SunHills"), operations and management control of the Highvale Mine from Prairie Mines and Royalty Ltd. ("PMRL"). PMRL employees working at the Highvale Mine were offered employment by SunHills which agreed to assume responsibility for certain pension plan and pension funding obligations, which we had previously funded through the payments made under the PMRL mining contracts. As a result, a pre-tax loss of $29 million was recognized during the first quarter, along with the corresponding liabilities.

We also entered into finance leases for certain mining equipment that was in use, or committed to, by PMRL in mining operations.

As a result, $8 million and $29 million in mining equipment have been capitalized to PP&E and the related finance lease obligations recognized during three and six months ended June 30, 2013. At the end of the lease term, we are eligible to purchase the assets, for a nominal amount.

Change in Estimates - Useful Lives

During the first quarter, management completed a comprehensive review of the estimated useful lives of our hydro assets, having regard for, among other things, our economic life cycle maintenance program and the existing condition of the assets. As a result, depreciation was reduced by $1 million and $2 million for the three and six months ended June 30, 2013, respectively. Pre-tax depreciation expense is expected to be reduced by $5 million for the year ended Dec. 31, 2013 and by $5 million annually thereafter.

Centralia Coal Inventory Writedown

During the three and six months ended June 30, 2013, we recognized a pre-tax writedown of $2 million and $16 million, respectively, related to the coal inventory at our Centralia plant to write the inventory down to its net realizable value.

SUBSEQUENT EVENTS

Centralia Thermal

On July 25, 2012, we announced that we entered into an 11-year agreement to provide electricity from the Centralia Thermal plant to Puget Sound Energy ("PSE"). The agreement was approved, with conditions, by the Washington Utilities and Transportation Commission ("WUTC") on Jan. 9, 2013. On Jan. 23, 2013, it was announced that PSE had filed a petition for reconsideration of certain conditions within the decision issued by the WUTC. On June 25, 2013, regulatory approval was confirmed by the WUTC and as of July 5, 2013, the contract is in effect in accordance with the WUTC's terms and conditions.

BUSINESS ENVIRONMENT

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Western United States ("U.S."), and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity and natural gas upon our financial results, refer to our 2012 Annual MD&A.

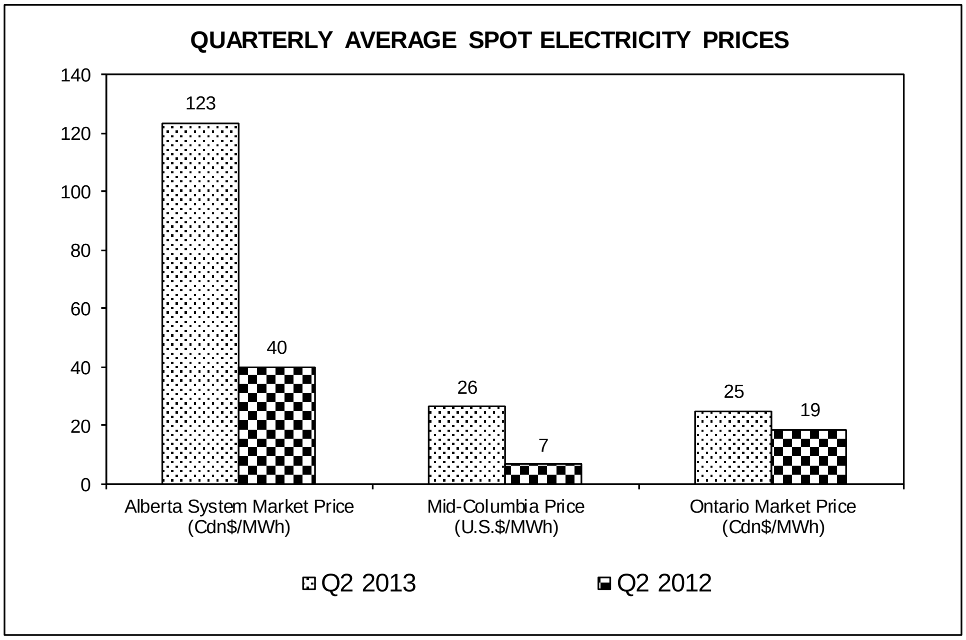
Contracted Cash Flows

During the second quarter of 2013, approximately 90 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also entered into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years. The average prices of these contracts for the balance of 2013 are approximately $60 per megawatt hour ("MWh") in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

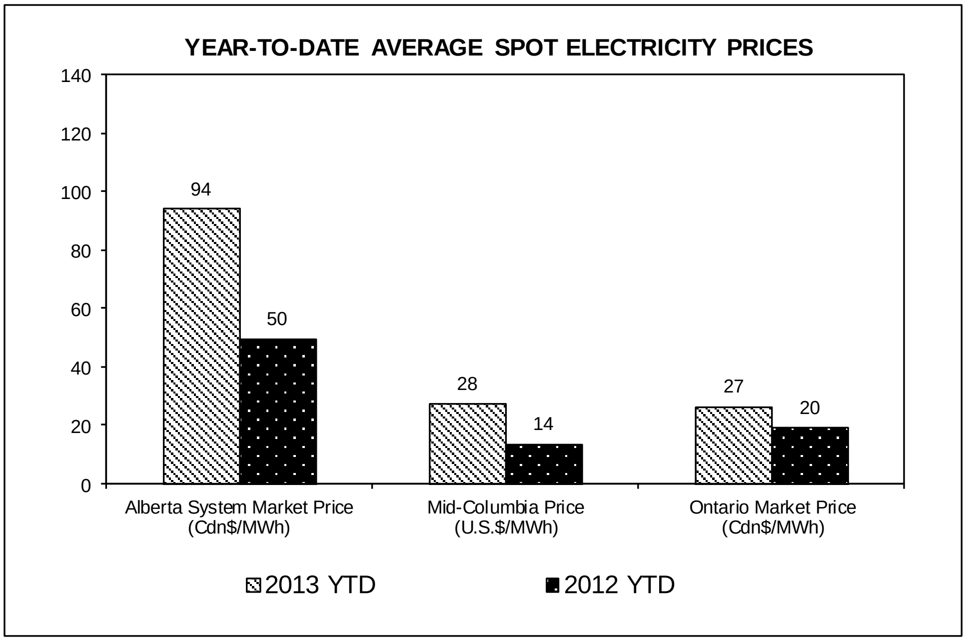
Electricity Prices

Please refer to the Business Environment section of our 2012 Annual MD&A for a full discussion of the spot electricity market and the impact of electricity prices on our business, as well as our strategy to hedge our risks associated with changes in these prices.

The average spot electricity prices for the three and six months ended June 30, 2013 and 2012 in our three major markets are shown in the following graphs.



For the three months ended June 30, 2013, average spot prices in Alberta increased compared to the same period in 2012 primarily due to tighter supply. In the Pacific Northwest, average spot prices increased due to lower hydro generation and higher natural gas prices. The average spot prices in Ontario increased compared to 2012 due to higher natural gas prices.



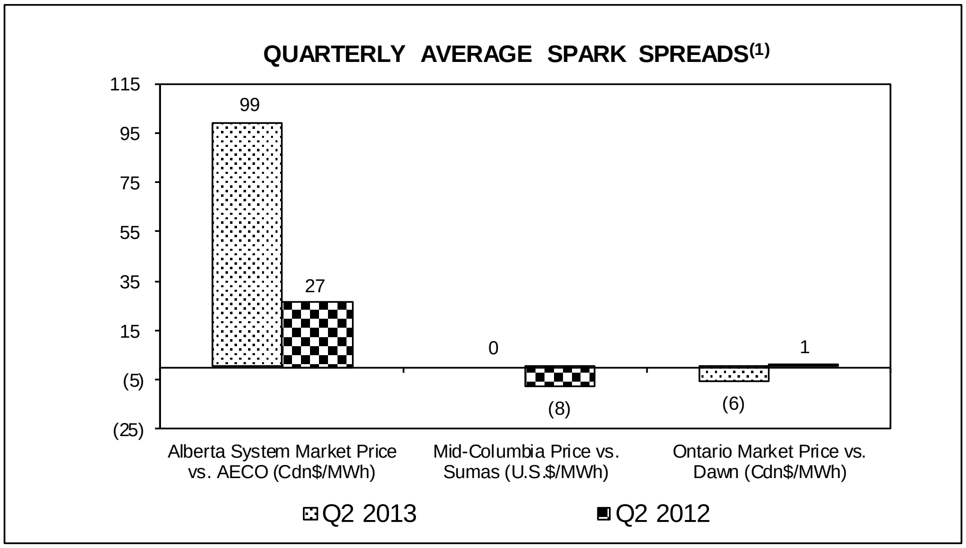
For the six months ended June 30, 2013, average spot prices in Alberta increased compared to the same period in 2012 primarily due to tighter supply. In the Pacific Northwest, average spot prices increased due to higher natural gas prices and lower hydro generation. The average spot prices in Ontario increased compared to 2012 due to higher natural gas prices.

Over the balance of 2013, power prices in Alberta are expected to be comparable to 2012 based on increased supply in the market. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, we expect that overall prices will still remain weak due to low natural gas prices and slow load growth.

Spark Spreads

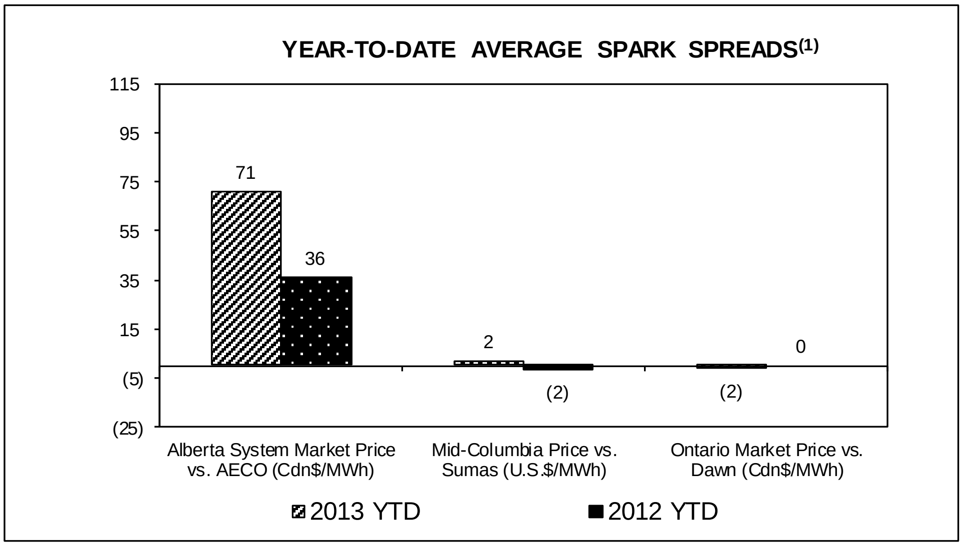
Please refer to the Business Environment section of our 2012 Annual MD&A for a full discussion of spark spreads and the impact of spark spreads on our business.

The average spark spreads for the three and six months ended June 30, 2013 and 2012 in our three major markets are shown in the following graphs.



(1) For a 7,000 British Thermal Units per Kilowatt hour heat rate plant.

For the three months ended June 30, 2013, average spark spreads increased in Alberta compared to the same period in 2012 due to higher prices driven by tighter supply. In the Pacific Northwest, average spark spreads increased due to lower hydro generation. For the three months ended June 30, 2013, average spark spreads decreased in Ontario compared to the same period in 2012 due to an increase in supply as a result of nuclear generating plants returning to service in the quarter.



(1) For a 7,000 British Thermal Units per Kilowatt hour heat rate plant.

For the six months ended June 30, 2013, average spark spreads increased in Alberta compared to the same period in 2012 due to higher prices driven by tighter supply. In the Pacific Northwest, average spark spreads increased due to lower hydro generation. For the six months ended June 30, 2013, average spark spreads decreased in Ontario compared to the same period in 2012 due to an increase in supply as a result of nuclear generating plants returning to service.

GENERATION: *TransAlta owns and operates hydro, wind, natural gas-fired and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2012 Annual MD&A.*

Generation Operations: *During the first quarter of 2013, we began commercial operations at New Richmond, a 68 MW wind farm in Québec. At June 30, 2013, our generating assets had 8,268 MW of gross generating capacity(1) in operation (7,926 MW net ownership interest) and 560 MW under restoration in the Sundance Units 1 and 2 major project. The following information excludes assets that are accounted for as a finance lease or using the equity method, which are discussed separately within this discussion of the Generation Segment.*

The results of Generation Operations are as follows:

	2013				2012	
3 months ended June 30	**Total**	**Comparable adjustments(2)**	**Comparable total(2)**	**Per installed MWh**	Comparable total(2)	Per installed MWh
Revenues	**528**	**8**	**536**	**29.68**	492	27.43
Fuel and purchased power	**187**	**-**	**187**	**10.36**	142	7.92
Gross margin	**341**	**8**	**349**	**19.32**	350	19.51
Operations, maintenance, and administration	**111**	**(1)**	**110**	**6.09**	105	5.85
Depreciation and amortization	**125**	**-**	**125**	**6.92**	134	7.47
Inventory writedown	**2**	**-**	**2**	**0.11**	9	0.50
Reversal of restructuring charges	**(1)**	**1**	**-**	**-**	-	-
Taxes, other than income taxes	**8**	**-**	**8**	**0.44**	7	0.39
Intersegment cost allocation	**3**	**-**	**3**	**0.17**	4	0.22
Operating income	**93**	**8**	**101**	**5.59**	91	5.08
Installed capacity (GWh)	**18,058**		**18,058**		17,937	
Production (GWh)	**7,592**		**7,592**		7,852	
Availability (%)	**70.8**		**70.8**		81.1	
Adjusted availability (%)(3)	**80.5**		**80.5**		86.7	

(1) We measure capacity as net maximum capacity (see glossary for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.

(2) Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

(3) Adjusted for economic dispatching at Centralia Thermal.

6 months ended June 30	2013 Total	2013 Comparable adjustments	2013 Comparable total	2013 Per installed MWh	2012 Comparable total	2012 Per installed MWh
Revenues	1,051	49	1,100	30.63	1,034	28.89
Fuel and purchased power	388	-	388	10.80	317	8.86
Gross margin	663	49	712	19.83	717	20.03
Operations, maintenance and administration	205	(1)	204	5.68	204	5.70
Depreciation and amortization	247	-	247	6.88	258	7.21
Inventory writedown	16	-	16	0.45	9	0.25
Reversal of restructuring charges	(1)	1	-	-	-	-
Taxes, other than income taxes	15	-	15	0.42	14	0.39
Intersegment cost allocation	7	-	7	0.19	7	0.20
Operating income	174	49	223	6.21	225	6.28
Installed capacity (GWh)	35,914		35,914		35,788	
Production (GWh)	17,704		17,704		16,765	
Availability (%)	81.1		81.1		86.3	
Adjusted availability (%)	86.0		86.0		89.1	

The outages at Centralia Thermal did not negatively impact our gross margins for the three and six months ended June 30, 2013 as we were able to extend our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Generation availability, after adjusting for economic dispatching, was 80.5 per cent and 86.0 per cent for the three and six months ended June 30, 2013, respectively. For the three and six months ended June 30, 2012, Generation availability, after adjusting for economic dispatching, was 86.7 per cent and 89.1 per cent, respectively.

Generation Operations Production and Comparable Gross Margins

Production volumes, comparable revenues, fuel and purchased power expenses, and comparable gross margins based on geographical regions and fuel types are presented below.

3 months ended June 30, 2013	Production (GWh)	Installed (GWh)	Comparable revenues	Comparable fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Comparable fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	4,509	7,003	188	96	92	26.85	13.71	13.14
Gas	562	778	38	8	30	48.84	10.28	38.56
Renewables	854	2,921	88	4	84	30.13	1.37	28.76
Total Western Canada	5,925	10,702	314	108	206	29.34	10.09	19.25
Gas	794	1,638	96	47	49	58.61	28.69	29.92
Renewables	397	1,592	40	2	38	25.13	1.26	23.87
Total Eastern Canada	1,191	3,230	136	49	87	42.11	15.17	26.94
Coal	132	2,929	52	18	34	17.75	6.15	11.60
Gas	344	1,197	34	12	22	28.40	10.03	18.37
Total International	476	4,126	86	30	56	20.84	7.27	13.57
	7,592	18,058	536	187	349	29.68	10.36	19.32

3 months ended June 30, 2012	Production (GWh)	Installed (GWh)	Comparable revenues	Comparable fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Comparable fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	4,732	7,032	215	85	130	30.57	12.09	18.48
Gas	546	778	21	4	17	26.99	5.14	21.85
Renewables	935	2,921	47	3	44	16.09	1.03	15.06
Total Western Canada	6,213	10,731	283	92	191	26.37	8.57	17.80
Gas	958	1,638	86	37	49	52.50	22.59	29.91
Renewables	335	1,442	32	2	30	22.19	1.39	20.80
Total Eastern Canada	1,293	3,080	118	39	79	38.31	12.66	25.65
Coal	-	2,929	63	5	58	21.51	1.71	19.80
Gas	346	1,197	28	6	22	23.39	5.01	18.38
Total International	346	4,126	91	11	80	22.06	2.67	19.39
	7,852	17,937	492	142	350	27.43	7.92	19.51

6 months ended June 30, 2013	**Production (GWh)**	**Installed (GWh)**	**Comparable revenues**	**Comparable fuel & purchased power**	**Comparable gross margin**	**Comparable revenues per installed MWh**	**Comparable fuel & purchased power per installed MWh**	**Comparable gross margin per installed MWh**
Coal	**9,784**	**13,929**	**416**	**190**	**226**	**29.87**	**13.64**	**16.23**
Gas	**1,230**	**1,547**	**68**	**15**	**53**	**43.96**	**9.70**	**34.26**
Renewables	**1,593**	**5,810**	**144**	**7**	**137**	**24.78**	**1.20**	**23.58**
Total Western Canada	**12,607**	**21,286**	**628**	**212**	**416**	**29.50**	**9.96**	**19.54**
Gas	**1,795**	**3,257**	**201**	**98**	**103**	**61.71**	**30.09**	**31.62**
Renewables	**822**	**3,165**	**82**	**4**	**78**	**25.91**	**1.26**	**24.65**
Total Eastern Canada	**2,617**	**6,422**	**283**	**102**	**181**	**44.07**	**15.88**	**28.19**
Coal	**1,810**	**5,825**	**123**	**49**	**74**	**21.12**	**8.41**	**12.71**
Gas	**670**	**2,381**	**66**	**25**	**41**	**27.72**	**10.50**	**17.22**
Total International	**2,480**	**8,206**	**189**	**74**	**115**	**23.03**	**9.02**	**14.01**
	17,704	**35,914**	**1,100**	**388**	**712**	**30.63**	**10.80**	**19.83**

6 months ended June 30, 2012	Production (GWh)	Installed (GWh)	Comparable revenues	Comparable fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Comparable fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	9,995	13,976	425	166	259	30.41	11.88	18.53
Gas	1,250	1,556	52	10	42	33.42	6.43	26.99
Renewables	1,686	5,842	95	6	89	16.26	1.03	15.23
Total Western Canada	12,931	21,374	572	182	390	26.76	8.52	18.24
Gas	1,961	3,276	185	80	105	56.47	24.42	32.05
Renewables	795	2,886	77	4	73	26.68	1.39	25.29
Total Eastern Canada	2,756	6,162	262	84	178	42.52	13.63	28.89
Coal	404	5,858	145	37	108	24.75	6.32	18.43
Gas	674	2,394	55	14	41	22.97	5.85	17.12
Total International	1,078	8,252	200	51	149	24.24	6.18	18.06
	16,765	35,788	1,034	317	717	28.89	8.86	20.03

Western Canada

Our Western Canada assets consist of coal, natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our Western Canadian operations.

The primary factors contributing to the change in production for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30 (GWh)	6 months ended June 30 (GWh)
Production, 2012	6,213	12,931
Higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage	(1,046)	(1,402)
Lower hydro volumes	(49)	(53)
Lower wind volumes	(33)	(41)
Higher (lower) production at natural gas-fired facilities	16	(20)
Lower planned outages at the Alberta coal facilities	179	462
Higher PPA customer demand	447	339
Market curtailments	193	304
Lower unplanned outages at Genesee Unit 3 and Keephills Unit 3	5	80
Other	-	7
Production, 2013	**5,925**	**12,607**

The primary factors contributing to the change in comparable gross margin for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30	6 months ended June 30
Comparable gross margin, 2012	191	390
Higher hydro margins	15	21
Lower planned outages at the Alberta coal facilities	3	19
Market curtailments	7	14
Lower unplanned outages at Genesee Unit 3 and Keephills Unit 3	-	4
Unfavourable coal pricing	(12)	(15)
Pricing, net of PPA penalties and unrealized mark-to-market movements	4	(7)
Higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage	-	(5)
Other	(2)	(5)
Comparable gross margin, 2013	**206**	**416**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our Eastern Canadian operations.

The primary factors contributing to the change in production for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30 (GWh)	6 months ended June 30 (GWh)
Production, 2012	1,293	2,756
Unfavourable market conditions at natural gas-fired facilities	(163)	(165)
Higher (lower) wind volumes	23	(8)
Lower hydro volumes	(7)	(7)
Commencement of commercial operations of New Richmond	43	43
Other	2	(2)
Production, 2013	**1,191**	**2,617**

The primary factors contributing to the change in gross margin for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30	6 months ended June 30
Gross margin, 2012	79	178
Commencement of commercial operations of New Richmond	5	5
Higher wind volumes	2	-
Favourable (unfavourable) contracted gas input costs	1	(1)
Other	-	(1)
Gross margin, 2013	**87**	**181**

International

Our International assets consist of coal, natural gas, and hydro facilities in various locations in the U.S., and natural gas and diesel assets in Australia. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our International operations.

The primary factors contributing to the change in production for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30 (GWh)	**6 months ended June 30 (GWh)**
Production, 2012	346	1,078
Lower economic dispatching at Centralia Thermal	753	2,054
Higher planned and unplanned outages at Centralia Thermal	(621)	(646)
Other	(2)	(6)
Production, 2013	**476**	**2,480**

The primary factors contributing to the change in comparable gross margin for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30	**6 months ended June 30**
Comparable gross margin, 2012	80	149
Lower contract pricing, including margins on purchased power	(25)	(60)
Coal pricing[1]	(1)	22
Other	2	4
Comparable gross margin, 2013	**56**	**115**

During the three and six months ended June 30, 2013, we recognized a pre-tax writedown of $2 million and $16 million, respectively, related to the coal inventory at our Centralia plant to write the inventory down to its net realizable value.

Comparable Operations, Maintenance, and Administration Expense

Comparable OM&A expense for the three months ended June 30, 2013 increased $5 million compared to the same period in 2012, primarily due to higher emergent costs, higher routine maintenance costs, higher costs that are recoverable through PPAs, and service allocations from other segments, partially offset by lower compensation costs.

Comparable OM&A expense for the six months ended June 30, 2013 was comparable to the same period in 2012.

(1) Coal price includes the impact of the inventory writedown which is not included in gross margin.

Depreciation and Amortization Expense

The primary factors contributing to the change in depreciation and amortization expense for the three and six months ended June 30, 2013 are presented below:

	3 months ended June 30	6 months ended June 30
Depreciation and amortization expense, 2012	134	258
Impact of asset impairments	(7)	(15)
Change in economic life[1]	(4)	(9)
Decrease in asset retirements	(7)	(7)
Change in useful lives of hydro assets	(1)	(2)
Increase in asset base	10	17
Other	-	5
Depreciation and amortization expense, 2013	**125**	**247**

Finance Leases

Solomon

On Sept. 28, 2012, we completed the acquisition from Fortescue Metals Group Ltd. ("Fortescue") of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility and associated Power Purchase Agreement ("Agreement") are accounted for as a finance lease and we began receiving payments under the Agreement in the fourth quarter of 2012. The facility is currently under construction and is expected to be commissioned during the third quarter of 2013.

Fort Saskatchewan

Fort Saskatchewan is a natural gas-fired facility with a gross generating capacity of 118 MW in operation, of which TransAlta Cogeneration, L.P. has a 60 per cent ownership interest (35 MW net ownership interest). Key operational information adjusted to reflect our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Availability (%)	**95.1**	69.5	**99.8**	86.0
Production (GWh)	**126**	82	**264**	219

Availability and production for the three and six months ended June 30, 2013 increased compared to the same periods in 2012 due to lower planned outages.

Total Finance Lease Income

Total finance lease income for the three and six months ended June 30, 2013 increased $10 million and $19 million, respectively, compared to the same periods in 2012 due to the payments we began receiving in October 2012 under the Agreement with Fortescue.

(1) As a result of amendments to Canadian federal regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation. The previous draft regulations proposed shut down after 45 years. The useful lives of these assets were changed in the third quarter of 2012.

Equity Investments

Our investments in joint ventures are accounted for using the equity method consist of our investments in CE Gen, Wailuku River Hydroelectric, L.P, TAMA Transmission, and CalEnergy.

Our interests in the CE Gen and Wailuku River Hydroelectric, L.P. joint ventures are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 839 MW of gross generating capacity (390 MW net ownership interest). The table below summarizes key operational information adjusted to reflect our interest in these investments:

	3 months ended June 30		**6 months ended June 30**	
	2013	2012	**2012**	2011
Availability (%)	**91.9**	93.2	**89.4**	93.1
Production (GWh)				
Gas	**68**	44	**208**	135
Renewables	**324**	296	**578**	596
Total production	**392**	340	**786**	731

Availability for the three months ended June 30, 2013 decreased compared to the same period in 2012 due to higher unplanned outages.

For the six months ended June 30, 2013, availability decreased compared to the same period in 2012 due to higher planned outages.

Production for the three months ended June 30, 2013 increased compared to the same period in 2012 due to higher customer demand, partially offset by higher unplanned outages.

For the six months ended June 30, 2013, production increased compared to the same period in 2012 due to higher customer demand, partially offset by higher planned outages.

Equity loss for the three months ended June 30, 2013 was $3 million compared to equity loss of $5 million for the same period in 2012. The increase is primarily due to favourable pricing, partially offset by higher unplanned outages.

For the six months ended June 30, 2013, equity loss was $7 million compared to equity loss of $5 million for the same period in 2012. The increase is primarily due to higher planned outages and unfavourable pricing during the first quarter.

Since 2001, a significant portion of the CE Gen plants have been operating under modified fixed energy price contracts. Commencing May 1, 2012, the terms of the contracts reverted to a pricing clause that permits the power purchaser to pay their short-run avoided costs (“SRAC”) as the price for power. The SRAC is linked to the price of natural gas. There can be no assurances that prices based on the avoided cost of energy after May 1, 2012 will result in revenues equivalent to those realized under the fixed energy price structure.

On June 18, 2013, we announced that CalEnergy, a joint venture with MidAmerican Energy Holdings Company, had executed an 86 MW long-term contract for renewable geothermal power with the City of Riverside which runs from 2016 to 2039. CalEnergy will purchase the power from CE Gen’s portfolio of geothermal generating facilities in California’s Imperial Valley.

E N E R G Y   T R A D I N G : *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving gross margins, while remaining within Value at Risk ("VaR") limits, is a key measure of Energy Trading's activities. Refer to the Value at Risk and Trading Positions discussion in the Risk Management section of our 2012 Annual MD&A for further discussion on VaR.*

Energy Trading utilizes contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. If the activities are performed on behalf of the Generation Segment, the results of these activities are included in the Generation Segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2012 Annual MD&A.

The results of the Energy Trading Segment, with all trading results presented on a net basis, are as follows:

	3 months ended June 30		**6 months ended June 30**	
	2013	2012	**2013**	2012
Revenues	**14**	(11)	**31**	6
Fuel and purchased power	**-**	-	**-**	-
Gross margin	**14**	(11)	**31**	6
Operations, maintenance, and administration	**6**	7	**14**	14
Depreciation and amortization	**-**	-	**-**	-
Intersegment cost allocation	**(3)**	(4)	**(7)**	(7)
Operating income (loss)	**11**	(14)	**24**	(1)

For the three and six months ended June 30, 2013, Energy Trading gross margins increased compared to the same periods in 2012 due to strong trading performance across all markets and prudent management of risk. The increase in comparable earnings is primarily due to higher earnings in the Energy Trading segment driven by strong trading performance across all markets.

OM&A expense for the three months ended June 30, 2013 decreased $1 million compared to the same period in 2012 due to lower compensation costs as a result of restructuring in the fourth quarter of 2012.

OM&A expense for the six months ended June 30, 2013 was comparable to the same period in 2012.

C O R P O R A T E : *Our Generation and Energy Trading Segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.*

The expenses incurred by the Corporate Segment are as follows:

	3 months ended June 30				**6 months ended June 30**			
	2013	**Comparable adjustments**	**Comparable total**	2012	**2013**	**Comparable adjustments**	**Comparable total**	2012
Operations, maintenance, and administration	**16**	**-**	**16**	20	**29**	**-**	**29**	42
Depreciation and amortization	**6**	**-**	**6**	5	**11**	**-**	**11**	10
Reversal of restructuring charges	**(1)**	**1**	**-**	-	**(1)**	**1**	**-**	-
Operating loss	**21**	**1**	**22**	25	**39**	**1**	**40**	52

OM&A expense for the three and six months ended June 30, 2013 decreased compared to the same periods in 2012 primarily due to lower compensation costs as a result of restructuring in the fourth quarter of 2012 and a continued focus on costs.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Interest on debt	**58**	58	**118**	114
Capitalized interest	**-**	(1)	**(2)**	(1)
Ineffectiveness on hedges	**-**	2	**-**	2
Interest expense	**58**	59	**116**	115
Accretion of provisions	**5**	5	**9**	9
Net interest expense	**63**	64	**125**	124

The change in net interest expense for the three and six months ended June 30, 2013, compared to the same periods in 2012, is shown below:

	3 months ended June 30	6 months ended June 30
Net interest expense, 2012	64	124
Lower (higher) capitalized interest	1	(1)
Lower interest rates	(1)	(1)
Unfavourable foreign exchange impacts	-	1
Lower ineffectiveness on hedges	(2)	(2)
Higher financing costs	-	1
Higher debt levels	1	3
Net interest expense, 2013	**63**	**125**

INCOME TAXES

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

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Earnings (loss) before income taxes	**44**	(712)	**35**	(602)
Income attributable to non-controlling interests	**(9)**	(5)	**(19)**	(18)
Equity loss	**3**	5	**7**	5
Impacts associated with certain de-designated and ineffective hedges	**8**	83	**49**	(2)
Asset impairment charges	**-**	365	**-**	365
Inventory writedown	**-**	(1)	**-**	33
Reversal of restructuring charges	**(2)**	-	**(2)**	**-**
Gain on sale of assets	**(10)**	-	**(10)**	(3)
Sundance Units 1 and 2 arbitration	**-**	247	**-**	247
Loss on assumption of pension obligations	**-**	-	**29**	-
Other non-comparable items	**1**	1	**1**	1
Earnings (loss) attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**35**	(17)	**90**	26
Income tax expense (recovery)	**10**	75	**(7)**	77
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**3**	29	**17**	(1)
Income tax recovery related to asset impairment charges	**-**	5	**-**	5
Income tax recovery related to inventory writedown	**-**	-	**-**	12
Income tax expense related to gain on sale of assets	**(1)**	-	**(1)**	(1)
Income tax recovery related to Sundance Units 1 and 2 arbitration	**-**	63	**-**	63
Income tax expense related to writeoff of deferred income tax assets	**-**	(169)	**-**	(169)
Income tax recovery related to deferred tax rate adjustment	**1**	-	**7**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	9
Income tax expense related to changes in corporate income tax rates	**-**	(8)	**-**	(8)
Income tax recovery related to loss on assumption of pension obligations	**-**	-	**7**	-
Income tax expense (recovery) excluding non-comparable items	**13**	(5)	**23**	(13)
Effective tax rate on earnings (loss) attributable to TransAlta shareholders excluding non-comparable items (%)	**37**	29	**26**	(50)

The income tax expense excluding non-comparable items for the three months ended June 30, 2013 increased compared to the same period in 2012 due to higher comparable earnings.

The income tax expense excluding non-comparable items for the six months ended June 30, 2013 increased compared to the same period in 2012 due to higher comparable earnings and the positive resolution of certain tax contingency matters in the prior year.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three and six months ended June 30, 2013 increased compared to the same periods in 2012 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, the effect of certain deductions that do not fluctuate with earnings, and due to the positive resolution of certain tax contingency matters in the prior period.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three months ended June 30, 2013 increased compared to the same period in 2012, primarily due to higher earnings at TransAlta Cogeneration, L.P.

Net earnings attributable to non-controlling interests for the six months ended June 30, 2013 was comparable to the same period in 2012.

FINANCIAL POSITION

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2012 to June 30, 2013:

	Increase/ (Decrease)	**Primary factors explaining change**
Cash and cash equivalents	40	Timing of receipts and payments
Accounts receivable	(148)	Timing of customer receipts
Prepaid expenses	33	Prepayment of annual insurance premiums, royalties, and service agreements
Inventory	29	Increase in overburden removal activity, and higher average coal costs partially offset by writedown of coal inventory
Investments	13	Additions to equity investments and favourable foreign exchange rates
Finance lease receivable (current and long-term)	16	Favourable foreign exchange rates
Property, plant, and equipment, net	72	Additions partially offset by depreciation
Deferred income tax assets	30	Tax benefits of losses related to U.S. operations
Risk management assets (current and long-term)	(100)	Price movements and changes in underlying positions and settlements
Other assets	10	Increase in long-term prepaids
Accounts payable and accrued liabilities	(121)	Timing of payments and lower capital accruals
Dividends payable	(18)	Increased dividends due to increased in total shares outstanding
Long-term debt (including current portion)	243	Increased borrowings under credit facilities and unfavourable foreign exchange rates
Finance lease obligation (including current portion)	25	Finance lease for mining equipment at the Highvale Mine
Decommissioning and other provisions (current and long-term)	14	Increase in decommissioning provisions
Deferred income tax liabilities	(21)	Increased income tax provisions
Risk management liabilities (current and long-term)	(77)	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	(46)	Net earnings for the period, share dividends, and issuance of common shares

FINANCIAL INSTRUMENTS

Refer to *Note 16* of the notes to the audited consolidated financial statements within our 2012 Annual Report and *Note 13* of our interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2013 for details on Financial Instruments. Refer to the Risk Management section of our 2012 Annual Report and *Note 14* of our 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, 2012.

Energy Trading 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 also have various contracts with terms that extend beyond five years. As forward price forecasts 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.

At June 30, 2013, total Level III financial instruments had a net asset carrying value of $11 million (Dec. 31, 2012 - $31 million net asset).

Certain of our hedging relationships had previously been de-designated and deemed ineffective for accounting purposes. The hedges were in respect of power production and the associated gains remain in AOCI until the underlying production occurs or until such time that the production has been assessed as highly probable not to occur. No gains related to these previously de-designated hedges were reclassified to earnings during the three and six months ended June 30, 2013 (June 30, 2012 - nil and $75 million pre-tax gain, respectively).

As at June 30, 2013, cumulative gains of $4 million, related to these and other cash flow hedges that were de-designated and no longer meet the criteria for hedge accounting, continued to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or if the forecasted transactions are assessed as highly probable not to occur.

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Condensed Consolidated Statements of Cash Flows for the three and six months ended June 30, 2013 compared to the same periods in 2012:

3 months ended June 30	2013	2012	Primary factors explaining change
Cash and cash equivalents, beginning of period	**50**	31	
Provided by (used in):			
Operating activities	**92**	78	Higher cash earnings of $35 million, partially offset by unfavourable changes in working capital of $21 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration in 2012
Investing activities	**(160)**	(175)	Decrease in additions to PP&E and intangibles of $24 million and an increase in realized gains on financial instruments of $22 million, partially offset by a net negative impact of $14 million related to changes in collateral received from or paid to counterparties, an unfavourable change in non-cash investing working capital balances of $12 million, and an increase in equity investments of $10 million
Financing activities	**86**	127	Decrease in borrowings under credit facilities of $11 million, an increase in common share cash dividends of $20 million, an increase in preferred share cash dividends of $4 million and a decrease in finance lease obligation of $4 million
Translation of foreign currency cash	**(1)**	-	
Cash and cash equivalents, end of period	**67**	61	

6 months ended June 30	2013	2012	Primary factors explaining change
Cash and cash equivalents, beginning of period	**27**	49	
Provided by (used in):			
Operating activities	**348**	261	Higher cash earnings of $25 million and favourable changes in working capital of $62 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration in 2012
Investing activities	**(310)**	(339)	Decrease in additions to PP&E and intangibles of $35 million and an increase in realized gains on financial instruments of $22 million, partially offset by a net negative impact of $6 million related to changes in collateral received from or paid to counterparties, an unfavourable change in non-cash investing working capital balances of $19 million, and an increase in equity investments of $10 million
Financing activities	**2**	90	Decrease in borrowings under credit facilities of $84 million, an increase in preferred share cash dividends of $5 million and a decrease in finance lease obligation of $4 million, partially offset by a decrease in common share cash dividends of $5 million due to dividends reinvested through the dividend reinvestment plan
Cash and cash equivalents, end of period	**67**	61	

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.

Our liquidity needs are met through a variety of sources, including cash generated from operations, borrowings 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 limited partners, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.5 billion as at June 30, 2013 compared to $4.2 billion as at Dec. 31, 2012. Long-term debt increased from Dec. 31, 2012 primarily due to higher borrowings under our syndicated credit facility and unfavourable changes in foreign exchange rates.

Credit Facilities

At June 30, 2013, we had a total of $2.1 billion (Dec. 31, 2012 - $2.0 billion) of committed credit facilities, of which $0.7 billion (Dec. 31, 2012 - $0.8 billion) is not drawn and is available, subject to customary borrowing conditions. At June 30, 2013, the $1.4 billion (Dec. 31, 2012 - $1.3 billion) of credit utilized under these facilities was comprised of actual drawings of $1.1 billion (Dec. 31, 2012 - $1.0 billion) and letters of credit of $0.3 billion (Dec. 31, 2012 - $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2017, 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 2014. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.7 billion available under the credit facilities, we also have $60 million of available cash.

Share Capital

On July 29, 2013, we had 266.3 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E first preferred shares outstanding. At June 30, 2013, we had 262.1 million (Dec. 31, 2012 - 254.7 million) common shares issued and outstanding. At June 30, 2013, we also had 32.0 million (Dec. 31, 2012 - 32.0 million) preferred shares issued and outstanding.

We issue common shares for cash proceeds, on exercise of stock options and other share-based payment plans, or for reinvestment of dividends. During February 2012, we added a Premium Dividend™ component to the Plan. Please refer to *Note 28* of our audited consolidated financial statements within our 2012 Annual Report for additional information regarding the amendments. On May 8, 2013, we announced that as a result of the current low share price environment, we are suspending the Premium Dividend™ component of the Plan following the payment of the quarterly dividend on July 1, 2013. Our Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remain effective in accordance with their current terms.

During the three months ended June 30, 2013, 3.7 million (June 30, 2012 - 2.4 million) common shares were issued for $53 million (June 30, 2012 - $43 million), which was primarily comprised of dividends reinvested under the terms of the Plan. During the six months ended June 30, 2013, 7.4 million (June 30, 2012 - 3.4 million) common shares were issued for $106 million (June 30, 2012 - $64 million), which was primarily comprised of dividends reinvested under the terms of the Plan.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At June 30, 2013, we provided letters of credit totalling $341 million (Dec. 31, 2012 - $336 million) and cash collateral of $18 million (Dec. 31, 2012 - $19 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Commitments

During March 2013, the New Richmond wind farm commenced operations and as such, the 15 year long-term service agreement for repairs and maintenance became effective. The future payments over the term of the agreement are approximately $42 million.

CLIMATE CHANGE AND THE ENVIRONMENT

In Alberta, there are requirements for coal-fired generation units to implement additional air emission controls for oxides of nitrogen (“NOx”), sulphur dioxide (“SO_2”), and particulate matter, once they reach the end of their respective PPAs, in most cases at 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta’s Clean Air Strategic Alliance (“CASA”). However, the release of the federal Greenhouse Gas (“GHG”) regulations may create a potential misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with the provincial government to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta’s generation supply.

In the U.S., on June 25, 2013, President Obama announced his Climate Action Plan, which sets out plans for GHG emission standards to be imposed by the Environmental Protection Agency (“EPA”) for new and existing power plants. Standards for new units are pending and standards for existing units are to be finalized by June 2015. State implementation plans are to be completed a year later. There will be few additional details as to how existing coal (and potentially natural gas) units might be treated until the EPA releases a draft rule.

In December 2011, the EPA issued national standards for mercury emissions from power plants. Existing sources will have up to four years to comply. We have already voluntarily installed mercury capture technology at our Centralia coal-fired plant, and began full capture operations in early 2012. We have also installed additional technology to further reduce NOx, consistent with the Washington State Bill passed in April 2011.

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Alberta Thermal operations in 2010 in order to meet the province’s 70 per cent reduction objectives, and voluntarily at our Centralia coal-fired plant in 2012. Our Keephills Unit 3 plant began operations in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at Genesee Unit 3. Uprate projects completed at our Keephills and Sundance plants are expected to improve the energy and emissions efficiency of those units.

2013 OUTLOOK

Business Environment

Power Prices

Over the balance of 2013, power prices in Alberta are expected to be marginally weaker than 2012. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, we expect that overall prices will still remain weak due to low natural gas prices and slow load growth.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. We are in discussions with the provincial government to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply. This may provide additional flexibility to coal-fired generators in meeting the regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of our 2012 Annual MD&A.

In addition, there are ongoing discussions between the federal and provincial governments regarding a national Air Quality Management System for air pollutants. In Alberta's recently released Clean Air Strategy, the province indicated that its provincial air quality management system will operationalize any national system. Our current outlook is that, for Alberta, provincial regulations will be considered as equivalent to any future national framework.

On Jan. 21, 2013, the Ontario government released a discussion paper for public input on reducing GHG emissions in the province, with the stated intent of developing GHG regulations for all major industrial sectors by 2015. No specific targets or regulatory approaches have yet been proposed.

In the U.S., the President's Climate Action Plan provides an indication of how GHG regulation of existing fossil-fuel based generation may unfold, although we expect the implementation process to take several years. Our agreement with Washington State, established in April 2011, provides regulatory clarity at the state level regarding an emissions regime related to the Centralia Coal plant until 2025. We expect this agreement may mitigate separate federal action from the EPA. Additionally, new federal air pollutant regulations for the power sector are anticipated, but are not expected to directly affect our coal-fired operations in Washington State.

Beginning in 2013, direct deliveries of power to the California Independent System Operator are subject to a compliance obligation established by the California Air Resources Board's ("CARB") cap and trade program. As CARB continues to finalize their regulations, we will stay at the forefront of regulatory changes to enable us to remain in compliance with the cap and trade program.

In Australia, the carbon tax implemented in July 2012 remains in place. As of July 1, 2013, the tax increased to AUS$24.15 per tonne. Subsequently, the Australian government announced that they would accelerate the transition to a cap and trade market to become effective in July 2014. At that point expectations are that the carbon price will drop. While TransAlta's gas-fired operations are subject to the tax, all related costs are flowed to contracted customers.

We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

The siting, construction, and operation of electrical energy facilities requires interaction with many stakeholders. Recently, certain stakeholders have brought actions against government agencies and owners over alleged adverse impacts of wind projects. We are monitoring these claims in order to assess the risk associated with these activities.

Economic Environment

In 2013, we expect slow to moderate growth in Alberta and Australia, and low growth in other markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no material counterparty losses in the second quarter of 2013. 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 for the remainder of 2013 due to Sundance Units 1 and 2 returning to service. Prior to the effect of any economic dispatching, overall production is expected to increase for the remainder 2013 due to lower planned outages, Sundance Units 1 and 2 returning to service, and the completion of the New Richmond wind farm. Adjusted availability, excluding the extended outages at Centralia Thermal, is expected to be in the range of 87 to 89 per cent in 2013 due to lower planned outages across the fleet.

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of our Sundance facility were shut down due to conditions observed in the boilers at both units. On Feb. 8, 2011, we issued a notice of termination for destruction based on the determination that the units could not be economically restored to service under the terms of the PPA. On July 20, 2012, an arbitration panel concluded that Units 1 and 2 were not to be economically destroyed and required the units to be restored to service. However, the panel affirmed that the event met the criteria of force majeure beginning Nov. 20, 2011 and continuing until such a time as each unit is returned to service. The cost to repair Sundance Units 1 and 2 is estimated at approximately $215 million and are expected to start generating production in the third and fourth quarter of 2013, respectively. The total estimated spend has increased by $25 million due to additional scope of work for balance of plant systems and equipment as well as higher labour costs due to an increase in rates. This work is being performed concurrently with the boiler repairs to prevent the need for a later outage for this work.

We expect an earlier return-to-service date of Aug. 6 for Sundance Unit 1.

Contracted Cash Flows

Through the use 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 next seven years. On an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming calendar year. As at the end of the second quarter of 2013, approximately 89 per cent of our 2013 capacity was contracted. The average prices of our short-term physical and financial contracts for the balance of 2013 are approximately $60 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 increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. In January 2013, we assumed, through SunHills, operating and management control of the Highvale Mine from PMRL. Coal costs for 2013, on a standard cost per tonne basis, are expected to be five to seven per cent higher than 2012 due to a decrease in tonnes delivered.

Although we own the Centralia mine in the State of Washington, it is not currently operational. Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2013 is expected to decrease between six to eight per cent.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges will be recognized in net earnings. For more information on the inventory impairment charges recorded in 2013, please refer to the Significant Events section of this MD&A.

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.

Operations, Maintenance, and Administration Costs

OM&A costs for 2013 are expected to be consistent or up to two per cent higher than OM&A costs in 2012 due to potential emergent maintenance work in the generation fleet and lower leasing recoveries. Entering 2013 we expected our OM&A to be consistent with 2012 OM&A, with costs savings from our organizational restructuring offset by additional costs as Sundance Units 1 and 2 are returned to service and the commencement of operations at our New Richmond wind farm.

Energy Trading

Earnings from our Energy Trading Segment are affected by prices in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure in order to maximize earnings while still maintaining an acceptable risk profile. Our target is for Energy Trading to contribute between $40 million and $60 million in gross margin for 2013.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. 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 net foreign denominated revenues.

Net Interest Expense

Net interest expense for 2013 is expected to increase compared to 2012 due to higher debt levels and lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar can affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, we may need additional liquidity in the future. We expect to maintain adequate available liquidity under our committed credit facilities.

Accounting Estimates

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of our 2012 Annual MD&A, are based on the current economic environment and outlook. As a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities and asset valuation for our asset impairment calculations.

Income Taxes

The effective tax rate on earnings excluding non-comparable items for 2013 is expected to be approximately 17 to 22 per cent, which is lower than the statutory tax rate of 25 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital Expenditures

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

Growth and Major Project Expenditures

We have one major project with a targeted completion date of Q4 2013. A summary is outlined below:

	Total Project		**2013**			
	Estimated spend	**Spent to date[(1)]**	**Estimated spend**	**Spent to date[(1)]**	**Target completion date**	**Details**
Growth						
New Richmond	212	217	15 - 25	29	Commercial operations began Q1 2013	A 68 MW wind farm in Québec
Major projects						
Sundance Units 1 and 2	215	149	155 - 170	105	Q3 2013 and Q4 2013	Sundance Units 1 and 2 comprising 560 MW of our Sundance power plant
Total major projects and growth	**427**	**366**	**170 - 195**	**134**		

The total estimated spend for Sundance Units 1 and 2 has increased by $25 million due to additional scope of work for balance of plant systems and equipment as well as higher labour costs due to an increase in rates. This work is being performed concurrently with the boiler repairs to prevent the need for a later outage for this work.

The total estimated spend for New Richmond is less than the amount incurred to date due to estimated recoveries to be received in 2013.

Transmission

For the three and six months ended June 30, 2013, a total of $2 million and $4 million, respectively, was spent on transmission projects. The estimated spend for 2013 on transmission projects is $7 million. Transmission projects consist of the major maintenance and reconfiguration of Alberta's transmission networks to increase capacity of power flow in the lines.

(1) Represents amounts spent as of June 30, 2013. During 2013, we also had a reduction of costs of $1 million on facilities that had previously commenced operations.

Sustaining Capital and Productivity Expenditures

For 2013, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Spent to date(1)
Routine capital	Expenditures to maintain our existing generating capacity	90 - 100	33
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	40 - 50	20
Finance leases	Payments related to mining equipment under finance leases	0 - 10	4
Planned major maintenance	Regularly scheduled major maintenance	165 - 185	95
Total sustaining expenditures		**295 - 345**	**152**
Productivity capital	Projects to improve power production efficiency	30 - 50	10
Total sustaining and productivity expenditures		**325 - 395**	**162**

During the six months, we acquired $29 million of mining equipment under finance leases and we made principal repayments of $4 million.

Our planned major maintenance program relates to regularly scheduled major maintenance activities and includes costs related to inspection, repair and maintenance, and replacement of existing components. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred. Details of the 2013 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2013	Spent to date(1)
Capitalized	90 - 105	75 - 80	165 - 185	95
Expensed	-	0 - 5	0 - 5	-
	90 - 105	75 - 85	165 - 190	95

	Coal	Gas and Renewables	Expected total	Lost to date
GWh lost	1,660 - 1,670	420 - 430	2,080 - 2,100	1,264

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, reinvested dividends under the Plan, 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.

(1) Represents amounts incurred as of June 30, 2013.

ACCOUNTING CHANGES

Adoption of New or Amended IFRS

On Jan. 1, 2013, we adopted the following new accounting standards that were previously issued by the International Accounting Standards Board ("IASB"):

IFRS 10 *Consolidated Financial Statements*

IFRS 10 replaces the parts of International Accounting Standard ("IAS") 27 *Consolidated and Separate Financial Statements* that deal with consolidated financial statements and Standing Interpretations Committee ("SIC") Interpretation 12 *Consolidation - Special Purpose Entities*. IFRS 10 defines the principle of control, establishes control as the basis for determining when entities are to be consolidated, and provides guidance on how to apply the principle of control to identify whether an investor controls an investee. Under IFRS 10, an investor controls an investee when it has all of the following: (i) power over the investee; (ii) exposure, or rights, to variable returns from the investee; and (iii) the ability to affect those returns.

We applied IFRS 10 retrospectively by reassessing whether, on Jan. 1, 2013, we had control of all of our previously consolidated entities. As a result of adopting IFRS 10, no changes arose in the entities we controlled and consolidated.

IFRS 11 *Joint Arrangements*

IFRS 11 replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principles-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its involvement in joint arrangements. A joint arrangement is an arrangement in which two or more parties have joint control. Under IFRS 11, joint arrangements are classified as either a joint operation or a joint venture, whereas under IAS 31, they were classified as a jointly controlled asset, jointly controlled operation or a jointly controlled entity. IFRS 11 requires the use of the equity method of accounting for interests in joint ventures, whereas IAS 31 permitted a choice of the equity method or proportionate consolidation for jointly controlled entities. Under IFRS 11, for joint operations, each party recognizes its respective share of the assets, liabilities, revenues and expenses of the arrangement, generally resulting in proportionate consolidation accounting.

We applied IFRS 11 retrospectively by reassessing the type of, and accounting for, each joint arrangement in existence at Jan. 1, 2013. No significant impacts resulted.

IFRS 12 *Disclosure of Interests in Other Entities*

IFRS 12 contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint arrangements, associates, and consolidated and unconsolidated structured entities (special purpose entities). The objective of IFRS 12 is that an entity should disclose information that helps financial statement users evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial statements. Disclosures arising from the adoption of IFRS 12 can be found in Notes 9, 12, and 20 of our interim consolidated financial statements.

IFRS 13 *Fair Value Measurement*

IFRS 13 establishes a single source of guidance for all fair value measurements required by other IFRS, clarifies the definition of fair value, and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability, or its own equity instrument at fair value. Our adoption of IFRS 13, prospectively on Jan. 1, 2013, did not have a material financial impact upon the consolidated financial position or results of operations, however, certain new or enhanced disclosures are required and can be found in Note 13 of our interim consolidated financial statements.

IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 *Presentation of Financial Statements* issued in June 2011 were intended to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The Consolidated Statements of Comprehensive Income (Loss) have been reorganized to comply with the required groupings.

IAS 19 *Employee Benefits*

Amendments to IAS 19 *Employee Benefits* are intended to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require the recognition of changes in defined benefit obligations and in fair value of plan assets when they occur, thus eliminating the “corridor approach” previously permitted. All actuarial gains and losses must be recognized immediately through other comprehensive income and the net pension liability or asset recognized at the full amount of the plan deficit or surplus. Additional changes relate to the presentation, into three components, of changes in defined benefit obligations and plan assets: service cost and net interest cost is recognized in net earnings and remeasurements are recognized in other comprehensive income. The net interest cost introduced in these amendments removes the concept of expected return on plan assets that was previously recognized in net earnings.

We calculate the net interest cost for our defined benefit plans by applying the discount rate at the beginning of the reporting period to the net defined benefit liability at the beginning of the reporting period. An expected return on plan assets is no longer calculated and recognized as part of pension expense. The elimination of the corridor method had no impact as we have, since adoption of IFRS, recognized actuarial gains and losses in OCI in the period in which they occurred.

On adoption, we applied the amendments retrospectively. The impacts as at Dec. 31, 2012 and Jan 1, 2012, respectively, were an increase in the cumulative prior periods’ pre-tax pension expense of $17 million and $11 million ($12 million and $8 million after-tax, respectively), as a result of the application of the net interest cost requirements.

For the three and six months ended June 30, 2012, OM&A expense increased by $2 million and $3 million, respectively, as a result of increased pension expense. Net after-tax actuarial losses on defined benefit plans as reported in OCI decreased by $1 million and $2 million, respectively, and basic and diluted net earnings per share attributable to common shareholders decreased by $0.01 and $0.01, respectively.

Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine ("IFRIC 20")*

IFRIC 20 clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods.

We recognize a stripping activity asset for our Highvale mine when all of the following are met: (i) it is probable that the future benefit associated with improved access to the coal reserves associated with the stripping activity will be realized; (ii) the component of the coal reserve to which access has been improved can be identified; and (iii) the costs related to the stripping activity associated with that component can be measured reliably. Costs include those directly incurred to perform the stripping activity as well as an allocation of directly attributable overheads. The resulting stripping activity asset is amortized on a unit-of-production basis over the expected useful life of the identified component that it relates to. The amortization is recognized as a component of the standard cost of coal inventory.

As required by the transitional provision of IFRIC 20, we applied the Interpretation to production stripping costs incurred on or after Jan 1, 2011, which will be the earliest comparative period presented within our annual financial statements for the year ended Dec. 31, 2013. The impacts on the Condensed Consolidated Statements of Financial Position as at Dec. 31, 2012 were to recognize \$9 million in costs as a stripping activity asset, increase coal inventory by \$2 million, both classified within Inventory, increase Deferred income tax liabilities by \$3 million, and decrease Retained deficit by \$8 million. The impacts on the Condensed Consolidated Statements of Financial Position as at Jan. 1, 2012 were to recognize \$9 million in costs as a stripping activity asset, decrease coal inventory by \$2 million, both classified within Inventory, increase Deferred income tax liabilities by \$2 million, and increase Retained earnings by \$5 million.

The impact of this change in accounting policy on the three and six months ended June 30, 2012 was not material.

IFRS 7 *Financial Instruments: Disclosures*

Amendments to IFRS 7 include disclosures about all recognized financial instruments that are set off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set off under IAS 32. The resulting disclosures can be found in Note 14 of our interim consolidated financial statements.

Annual Improvements 2009-2011

In May 2012, the IASB issued a collection of necessary, non-urgent amendments to several IFRS resulting from its annual improvements process. We have applied the amendments, as applicable, on Jan. 1, 2013. None of the amendments, which are generally technical and narrow in scope, had a material financial impact upon the consolidated financial position or results of operations.

FUTURE ACCOUNTING CHANGES

Additional new or amended accounting standards that have been previously issued by the IASB but are not yet effective, and have not yet been applied, are as follows: IFRS 9 *Financial Instruments*, IAS 32 *Financial Instruments: Presentation*, and *Investment Entities* (Amendments to IFRS 10 and 11 and IAS 27). Please refer to the Future Accounting Changes section of our 2012 Annual MD&A for more 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 (loss)" in our Condensed Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2013 and 2012. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

NON-IFRS MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These Non-IFRS measures are not necessarily comparable to a similarly titled measure of another company.

Presenting earnings on a comparable basis, comparable gross margin, comparable operating income, and comparable EBITDA from period to period provides management and investors with supplemental information to evaluate earnings trends in comparison with results from prior periods. In calculating these items, we exclude the impact related to certain hedges that are either de-designated or deemed ineffective for accounting purposes, as management believes that these transactions are not representative of our business operations. As these gains (losses) have already been recognized in earnings in current or prior periods, future reported earnings will be lower; however, the expected cash flows from these contracts will not change. In calculating comparable earnings measures we have also excluded the 2012 coal inventory writedown, as the recognition of the writedown is related to the hedges that were de-designated or deemed ineffective during prior quarters.

Other adjustments to earnings, such as the income tax recovery related to the deferred tax rate adjustment, the income tax recovery related to the resolution of certain outstanding tax matters, the loss on assumption of pension obligations, the gain on sale of assets, the reversal of restructuring charges, the flood recovery costs, asset impairment charges, the impact of the Sundance Units 1 and 2 arbitration, the income tax expense related to the writeoff of deferred income tax assets, the income tax expense related to changes in corporate income tax rates, and the writeoff of Project Pioneer costs have also been excluded 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.

Comparable operating income and EBITDA also include the earnings from the finance lease facilities that we operate. The finance lease income is used as a proxy for the operating income and EBITDA of these facilities.

Net Earnings on a Comparable Basis

Net earnings on a comparable basis are reconciled to net earnings attributable to common shareholders below:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Net earnings (loss) attributable to common shareholders	**15**	(798)	**4**	(710)
Impacts associated with certain de-designated and ineffective hedges, net of tax	**5**	54	**32**	(1)
Asset impairment charges, net of tax	**-**	360	**-**	360
Inventory writedown, net of tax	**-**	(1)	**-**	21
Reversal of restructuring charges, net of tax	**(2)**	-	**(2)**	-
Sundance Units 1 and 2 arbitration, net of tax	**-**	184	**-**	184
Income tax expense related to writeoff of deferred income tax assets	**-**	169	**-**	169
Income tax recovery related to deferred tax rate adjustment	**(1)**	-	**(7)**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	(9)
Income tax expense related to changes in corporate income tax rates	**-**	8	**-**	8
Gain on sale of assets, net of tax	**(9)**	-	**(9)**	(2)
Writeoff of Project Pioneer costs, net of tax	**-**	1	**-**	1
Loss on assumption of pension obligations, net of tax	**-**	-	**22**	-
Flood related maintenance costs, net of tax	**1**	-	**1**	-
Net earnings (loss) on a comparable basis	**9**	(23)	**41**	21
Weighted average number of common shares outstanding in the period	**262**	227	**260**	226
Net earnings (loss) on a comparable basis per share	**0.03**	(0.10)	**0.16**	0.09

Comparable Gross Margin

Comparable gross margin is calculated as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Gross margin	**355**	256	**694**	725
Impacts associated with certain de-designated and ineffective hedges	**8**	83	**49**	(2)
Impacts to revenue associated with Sundance Units 1 and 2[1]	**-**	(10)	**-**	(20)
Comparable gross margin	**363**	329	**743**	703

(1) The results have been adjusted retroactively for the impact of Sundance Units 1 and 2. Comparative figures have also been adjusted in this table only to provide period over period comparability.

Comparable Operating Income

A reconciliation of comparable operating income is as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Operating income (loss)	**83**	(396)	**159**	(225)
Impacts associated with certain de-designated and ineffective hedges	**8**	83	**49**	(2)
Asset impairment charges	**-**	365	**-**	365
Inventory writedown	**-**	(1)	**-**	33
Reversal of restructuring charges	**(2)**	-	**(2)**	-
Finance lease income	**12**	2	**23**	4
Flood related maintenance costs	**1**	-	**1**	-
Writeoff of Project Pioneer costs	**-**	1	**-**	1
Comparable operating income	**102**	54	**230**	176

Comparable EBITDA

Presenting comparable EBITDA from period to period provides management and investors with a proxy for the amount of cash generated from operating activities before net interest expense, non-controlling interests, income taxes, and working capital adjustments.

A reconciliation of comparable EBITDA to operating income is as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Operating income (loss)	**83**	(396)	**159**	(225)
Asset impairment charges	**-**	365	**-**	365
Inventory writedown	**-**	(1)	**-**	33
Reversal of restructuring charges	**(2)**	-	**(2)**	-
Finance lease income	**12**	2	**23**	4
Depreciation and amortization per the Consolidated Statements of Cash Flows(1)	**145**	149	**284**	290
Impacts associated with certain de-designated and ineffective hedges	**8**	83	**49**	(2)
Impacts to revenue associated with Sundance Units 1 and 2	**-**	(10)	**-**	(20)
Flood related maintenance costs	**1**	-	**1**	-
Writeoff of Project Pioneer costs	**-**	1	**-**	1
Comparable EBITDA	**247**	193	**514**	446

(1) To calculate comparable EBITDA, we use depreciation and amortization per the Condensed Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in fuel and purchased power on the Condensed Consolidated Statements of Earnings.

Funds from Operations and Funds from Operations per Share

Presenting funds from operations and funds from operations per share from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Funds from operations per share is calculated as follows using the weighted average number of common shares outstanding during the period:

	3 months ended June 30		**6 months ended June 30**	
	2013	2012	**2013**	2012
Cash flow from operating activities	**92**	78	**348**	261
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	204	**-**	204
Payment of restructuring costs	**-**	-	**4**	-
Timing of payments related to assumption of pension obligations	**(2)**	-	**7**	-
Flood related maintenance costs	**1**	-	**1**	-
Change in non-cash operating working capital balances	**93**	(132)	**16**	(126)
Funds from operations	**184**	150	**376**	339
Weighted average number of common shares outstanding in the period	**262**	227	**260**	226
Funds from operations per share	**0.70**	0.66	**1.45**	1.50

Free Cash Flow (Deficiency)

Free cash flow (deficiency) represents the amount of cash generated from operations by our business, before changes in working capital that is available to invest in growth initiatives, make scheduled principal repayments of debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash flow with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects.

Sustaining capital and productivity expenditures for the three months ended June 30, 2013 represent total additions to property, plant, and equipment and intangibles per the Condensed Consolidated Statements of Cash Flows less $60 million that we have invested in projects and growth. For the same period in 2012, we invested $45 million in projects and growth. For the six months ended June 30, 2013 and 2012, we invested $137 million and $82 million, respectively, in projects and growth.

The reconciliation between cash flow from operating activities and free cash flow is outlined below:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Cash flow from operating activities	**92**	78	**348**	261
Add (deduct):				
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	204	**-**	204
Changes in non-cash operating working capital	**93**	(132)	**16**	(126)
Sustaining capital and productivity expenditures	**(107)**	(141)	**(162)**	(248)
Dividends paid on common shares[1]	**(43)**	(23)	**(63)**	(68)
Dividends paid on preferred shares	**(10)**	(6)	**(19)**	(14)
Distributions paid to subsidiaries' non-controlling interests	**(16)**	(14)	**(35)**	(33)
Free cash flow (deficiency)	**9**	(34)	**85**	(24)

We seek to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to our business.

SELECTED QUARTERLY INFORMATION

	Q3 2012	Q4 2012	Q1 2013	**Q2 2013**
Revenue	522	646	540	**542**
Net earnings (loss) attributable to common shareholders	56	39	(11)	**15**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.24	0.15	(0.04)	**0.06**
Comparable earnings per share	0.18	0.22	0.12	**0.03**

	Q3 2011	Q4 2011	Q1 2012	Q2 2012
Revenue	613	688	644	398
Net earnings (loss) attributable to common shareholders	50	24	88	(798)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.22	0.11	0.39	(3.52)
Comparable earnings (loss) per share	0.27	0.13	0.20	(0.10)

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.

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* (“Exchange Act”) are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without

(1) Net of dividends reinvested under the Plan.

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 June 30, 2013, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD-LOOKING STATEMENTS

This MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "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 the following: expectations relating to the timing and completion of the Offering, the timing and the completion and commissioning of projects under development, including uprates and major projects, and their attendant costs; our estimated spend on matters relating to the recent flood in Alberta, spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the impact of certain hedges on future reported earnings and cash flows; expectations related to future earnings and cash flow from operating and contracting activities; 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; expected impacts of fewer anticipated turnarounds, load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us, as well as the cost of complying with resulting regulations and laws; our trading strategy 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; expectations for the outcome of existing or potential legal and contractual claims; 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 U.S. dollar; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment; our credit practices; the estimated contribution of Energy Trading activities to gross margin; and expectations relating to the establishment of TransAlta Renewables and the successful completion of the Offering.

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; 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 disasters; the threat of domestic terrorism and cyber-attacks; equipment failure; energy trading risks; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal and contractual proceedings involving the Corporation; reliance on key personnel; labour relations matters; development projects and acquisitions; and the satisfactory receipt of applicable regulatory approvals for, and the successful marketing of, the Offering. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2012 Annual MD&A and under the heading “Risk Factors” in our 2013 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.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(in millions of Canadian dollars except per share amounts)

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Unaudited		*(Restated)**		*(Restated)**
Revenues *(Note 6)*	**542**	398	**1,082**	1,042
Fuel and purchased power *(Note 7)*	**187**	142	**388**	317
Gross margin	**355**	256	**694**	725
Operations, maintenance, and administration *(Note 7)*	**133**	133	**248**	261
Depreciation and amortization	**131**	139	**258**	268
Asset impairment charges *(Note 8)*	**-**	365	**-**	365
Inventory writedown *(Note 16)*	**2**	8	**16**	42
Reversal of restructuring charges *(Note 19)*	**(2)**	-	**(2)**	-
Taxes, other than income taxes	**8**	7	**15**	14
Operating income (loss)	**83**	(396)	**159**	(225)
Finance lease income	**12**	2	**23**	4
Equity loss *(Note 9)*	**(3)**	(5)	**(7)**	(5)
Sundance Units 1 and 2 arbitration *(Note 4)*	**-**	(247)	**-**	(247)
Gain on sale of assets *(Note 5)*	**10**	-	**10**	3
Other income	**-**	1	**-**	1
Foreign exchange gain (loss)	**5**	(3)	**4**	(9)
Loss on assumption of pension obligations *(Note 3)*	**-**	-	**(29)**	-
Net interest expense *(Notes 10 and 14)*	**(63)**	(64)	**(125)**	(124)
Earnings (loss) before income taxes	**44**	(712)	**35**	(602)
Income tax expense (recovery) *(Note 11)*	**10**	75	**(7)**	77
Net earnings (loss)	**34**	(787)	**42**	(679)
Net earnings (loss) attributable to:				
TransAlta shareholders	**25**	(792)	**23**	(697)
Non-controlling interests	**9**	5	**19**	18
	34	(787)	**42**	(679)
Net earnings (loss) attributable to TransAlta shareholders	**25**	(792)	**23**	(697)
Preferred share dividends *(Note 23)*	**10**	6	**19**	13
Net earnings (loss) attributable to common shareholders	**15**	(798)	**4**	(710)
Weighted average number of common shares outstanding in the period *(millions)*	**262**	227	**260**	226
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.06**	(3.52)	**0.02**	(3.14)

** See Note 2 for prior period restatements.*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Unaudited		*(Restated)**		*(Restated)**
Net earnings	**34**	(787)	**42**	(679)
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**4**	(13)	**11**	(22)
Losses on derivatives designated as cash flow hedges, net of tax(2)	**-**	(2)	**-**	(2)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(3)	**-**	-	**1**	1
Total items that will not be reclassified subsequently to net earnings	**4**	(15)	**12**	(23)
Gains on translating net assets of foreign operations	**7**	45	**32**	13
Losses on financial instruments designated as hedges of foreign operations, net of tax(4)	**(8)**	(32)	**(29)**	(11)
Gains on derivatives designated as cash flow hedges, net of tax(5)	**13**	20	**27**	11
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(6)	**(20)**	(39)	**(39)**	(48)
Other comprehensive income (loss) of equity investees, net of tax(7)	**2**	-	**-**	-
Total items that may be reclassified subsequently to net earnings	**(6)**	(6)	**(9)**	(35)
Other comprehensive income (loss)	**(2)**	(21)	**3**	(58)
Total comprehensive income (loss)	**32**	(808)	**45**	(737)
Total comprehensive income (loss) attributable to:				
Common shareholders	**22**	(813)	**18**	(748)
Non-controlling interests	**10**	5	**27**	11
	32	(808)	**45**	(737)

** See Note 2 for prior period restatements.*

(1) Net of income tax expense of 2 and 4 for the three and six months ended June 30, 2013 (2012 - 4 and 7 recovery), respectively.

(2) Net of income tax expense of nil for the three and six months ended June 30, 2013 (2012 - nil), respectively.

(3) Net of income tax recovery of 1 for the three and six months ended June 30, 2013 (2012 - nil), respectively.

(4) Net of income tax recovery of 1 and 4 for the three and six months ended June 30, 2013 (2012 - 5 and 2 recovery), respectively.

(5) Net of income tax recovery of 2 and 4 for the three and six months ended June 30, 2013 (2012 - 1 and 2 expense), respectively.

(6) Net of income tax expense of 2 and 5 for the three and six months ended June 30, 2013 (2012 - 6 and 23 expense), respectively.

(7) Net of income tax expense of 1 and nil for the three and six months ended June 30, 2013 (2012 -nil), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**June 30, 2013**	Dec. 31, 2012 *(Restated)**	Jan. 1, 2012 *(Restated)**
Cash and cash equivalents *(Note 15)*	**67**	27	49
Accounts receivable	**449**	597	541
Current portion of finance lease receivable	**3**	2	3
Collateral paid *(Note 14)*	**18**	19	45
Prepaid expenses	**40**	7	8
Risk management assets *(Notes 13 and 14)*	**116**	201	391
Inventory *(Note 16)*	**122**	93	92
Income taxes receivable	**6**	3	2
	821	949	1,131
Investments *(Note 9)*	**185**	172	193
Long-term receivable	**-**	-	18
Long-term portion of finance lease receivable	**372**	357	42
Property, plant, and equipment *(Note 17)*			
Cost	**11,770**	11,481	11,386
Accumulated depreciation	**(4,654)**	(4,437)	(4,115)
	7,116	7,044	7,271
Goodwill	**447**	447	447
Intangible assets	**281**	284	276
Deferred income tax assets	**80**	50	169
Risk management assets *(Notes 13 and 14)*	**54**	69	99
Other assets *(Note 18)*	**100**	90	90
Total assets	**9,456**	9,462	9,736
Accounts payable and accrued liabilities	**374**	495	463
Decommissioning and other provisions *(Note 19)*	**24**	33	99
Collateral received *(Note 14)*	**-**	2	16
Risk management liabilities *(Notes 13 and 14)*	**103**	167	208
Income taxes payable	**12**	6	22
Dividends payable *(Notes 22 and 23)*	**57**	75	67
Current portion of finance lease obligation *(Note 3)*	**8**	-	-
Current portion of long-term debt *(Notes 13, 14, and 20)*	**524**	607	316
	1,102	1,385	1,191
Long-term debt *(Notes 13, 14, and 20)*	**3,936**	3,610	3,721
Finance lease obligation *(Note 3)*	**17**	-	-
Decommissioning and other provisions *(Note 19)*	**302**	279	283
Deferred income tax liabilities	**412**	433	486
Risk management liabilities *(Notes 13 and 14)*	**93**	106	142
Deferred credits and other long-term liabilities *(Note 21)*	**300**	301	281
Equity			
Common shares *(Note 22)*	**2,832**	2,726	2,273
Preferred shares *(Note 23)*	**781**	781	562
Contributed surplus	**9**	9	9
Retained earnings (deficit)	**(509)**	(362)	524
Accumulated other comprehensive loss *(Note 24)*	**(141)**	(136)	(94)
Equity attributable to shareholders	**2,972**	3,018	3,274
Non-controlling interests *(Note 12)*	**322**	330	358
Total equity	**3,294**	3,348	3,632
Total liabilities and equity	**9,456**	9,462	9,736

** See Note 2 for prior period restatements.*

Contingencies *(Note 25)*

Commitments *(Note 26)*

Subsequent events *(Note 30)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

6 months ended June 30, 2013

Unaudited	**Common shares**	**Preferred shares**	**Contributed surplus**	**Retained deficit**	**Accumulated other comprehensive income (loss)(1)**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec. 31, 2012	2,726	781	9	(362)	(136)	3,018	330	3,348
Net earnings (loss)	-	-	-	23	-	23	19	42
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	3	3	-	3
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(19)	(19)	8	(11)
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	11	11	-	11
Other comprehensive loss of equity investees, net of tax	-	-	-	-	-	-	-	-
Total comprehensive income						18	27	45
Common share dividends	-	-	-	(151)	-	(151)	-	(151)
Preferred share dividends	-	-	-	(19)	-	(19)	-	(19)
Distributions to non-controlling interests	-	-	-	-	-	-	(35)	(35)
Common shares issued	106	-	-	-	-	106	-	106
Balance, June 30, 2013	**2,832**	**781**	**9**	**(509)**	**(141)**	**2,972**	**322**	**3,294**

6 months ended June 30, 2012

*(Restated)**

Unaudited	Common shares	Preferred shares	Contributed surplus	Retained earnings (deficit)	Accumulated other comprehensive income (loss)(1)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2011	2,273	562	9	524	(94)	3,274	358	3,632
Net earnings (loss)	-	-	-	(697)	-	(697)	18	(679)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	-	-	-	-
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(29)	(29)	(7)	(36)
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(22)	(22)	-	(22)
Total comprehensive income						(748)	11	(737)
Common share dividends	-	-	-	(131)	-	(131)	-	(131)
Preferred share dividends	-	-	-	(13)	-	(13)	-	(13)
Distributions to non-controlling interests	-	-	-	-	-	-	(33)	(33)
Common shares issued	62	-	-	-	-	62	-	62
Balance, June 30, 2012	2,335	562	9	(317)	(145)	2,444	336	2,780

** See Note 2 for prior period restatements.*

(1) Refer to Note 22 for details on components of, and changes in, Accumulated other comprehensive income (loss).

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Unaudited		*(Restated)**		*(Restated)**
Operating activities				
Net earnings (loss)	**34**	(787)	**42**	(679)
Depreciation and amortization *(Note 27)*	**145**	149	**284**	290
Gain on sale of assets *(Note 5)*	**-**	-	**-**	(3)
Accretion of provisions *(Note 19)*	**5**	5	**9**	9
Decommissioning and restoration costs settled *(Note 19)*	**(8)**	(7)	**(13)**	(13)
Deferred income tax expense (recovery) *(Note 11)*	**(8)**	78	**(33)**	81
Unrealized loss from risk management activities	**18**	94	**59**	25
Unrealized foreign exchange (gain) loss	**(3)**	2	**1**	11
Provisions	**7**	(2)	**-**	(2)
Asset impairment charges *(Note 8)*	**-**	365	**-**	365
Sundance Units 1 and 2 impairment charge *(Notes 4 and 8)*	**-**	43	**-**	43
Equity loss, net of distributions received *(Note 9)*	**3**	5	**7**	5
Other non-cash items	**(8)**	1	**8**	3
Cash flow from (used in) operations before changes in working capital	**185**	(54)	**364**	135
Change in non-cash operating working capital balances *(Note 28)*	**(93)**	132	**(16)**	126
Cash flow from operating activities	**92**	78	**348**	261
Investing activities				
Additions to property, plant, and equipment *(Note 17)*	**(157)**	(175)	**(282)**	(312)
Additions to intangibles	**(6)**	(12)	**(13)**	(18)
Addition to equity investments	**(10)**	-	**(10)**	-
Proceeds on sale of property, plant, and equipment *(Note 17)*	**1**	-	**1**	-
Proceeds on sale of assets *(Note 5)*	**-**	-	**-**	3
Realized gains (losses) on financial instruments	**14**	(8)	**12**	(10)
Net decrease in collateral received from counterparties	**(1)**	(3)	**(2)**	(3)
Net (increase) decrease in collateral paid to counterparties	**(1)**	15	**2**	9
Decrease in finance lease receivable	**-**	-	**1**	1
Other	**2**	(2)	**2**	(7)
Change in non-cash investing working capital balances	**(2)**	10	**(21)**	(2)
Cash flow used in investing activities	**(160)**	(175)	**(310)**	(339)
Financing activities				
Net increase in borrowings under credit facilities *(Note 20)*	**162**	173	**129**	213
Repayment of long-term debt *(Note 20)*	**(3)**	(3)	**(5)**	(5)
Dividends paid on common shares *(Note 22)*	**(43)**	(23)	**(63)**	(68)
Dividends paid on preferred shares *(Note 23)*	**(10)**	(6)	**(19)**	(14)
Net proceeds on issuance of common shares	**-**	1	**-**	1
Distributions paid to subsidiaries' non-controlling interests *(Note 12)*	**(16)**	(14)	**(35)**	(33)
Decrease in finance lease obligation	**(4)**	-	**(4)**	-
Other	**-**	(1)	**(1)**	(4)
Cash flow from financing activities	**86**	127	**2**	90
Cash flow from operating, investing, and financing activities	**18**	30	**40**	12
Effect of translation on foreign currency cash	**(1)**	-	**-**	-
Increase in cash and cash equivalents	**17**	30	**40**	12
Cash and cash equivalents, beginning of period	**50**	31	**27**	49
Cash and cash equivalents, end of period	**67**	61	**67**	61
Cash income taxes paid	**12**	11	**25**	27
Cash interest paid	**91**	68	**120**	114

** See Note 2 for prior period restatements.*

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, these should be read in conjunction with the Corporation's most recent annual consolidated financial statements.

The unaudited interim condensed consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Refer to the discussion on the adoption of International Financial Reporting Standards ("IFRS") 10 *Consolidated Financial Statements*, found in Note 2(A) for information on the impacts of applying the new IFRS definition of control.

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 July 29, 2013.

B. Use of Estimates

The preparation of these condensed consolidated financial statements in accordance with IFRS requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. 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(W) of the 2012 annual consolidated financial statements for a more detailed discussion of the critical accounting judgments and key sources of estimation uncertainty.

2. ACCOUNTING CHANGES

A. Adoption of New or Amended IFRS

On Jan. 1, 2013, the Corporation adopted the following new accounting standards that were previously issued by the International Accounting Standards Board ("IASB"):

I. IFRS 10 *Consolidated Financial Statements*

IFRS 10 replaces the parts of IAS 27 *Consolidated and Separate Financial Statements* that deal with consolidated financial statements and Standing Interpretations Committee ("SIC") Interpretation 12 *Consolidation - Special Purpose Entities*. IFRS 10 defines the principle of control, establishes control as the basis for determining when entities are to be consolidated, and provides guidance on how to apply the principle of control to identify whether an investor controls an investee. Under IFRS 10, an investor controls an investee when it has all of the following: (i) power over the investee; (ii) exposure, or rights, to variable returns from the investee; and (iii) the ability to affect those returns.

IFRS 10 was applied retrospectively by the Corporation by reassessing whether, on Jan. 1, 2013, the Corporation had control of all of its previously consolidated entities. As a result of adopting IFRS 10, no changes arose in the entities controlled and consolidated by the Corporation.

II. IFRS 11 *Joint Arrangements*

IFRS 11 replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities - Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principles-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its involvement in joint arrangements. A joint arrangement is an arrangement in which two or more parties have joint control. Under IFRS 11, joint arrangements are classified as either a joint operation or a joint venture, whereas under IAS 31, they were classified as a jointly controlled asset, jointly controlled operation or a jointly controlled entity. IFRS 11 requires the use of the equity method of accounting for interests in joint ventures, whereas IAS 31 permitted a choice of the equity method or proportionate consolidation for jointly controlled entities. Under IFRS 11, for joint operations, each party recognizes its respective share of the assets, liabilities, revenues, and expenses of the arrangement, generally resulting in proportionate consolidation accounting.

IFRS 11 was applied retrospectively by the Corporation by reassessing the type of, and accounting for, each joint arrangement in existence at Jan. 1, 2013. No significant impacts resulted.

III. IFRS 12 *Disclosure of Interests in Other Entities*

IFRS 12 contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint arrangements, associates, and consolidated and unconsolidated structured entities (special purpose entities). The objective of IFRS 12 is that an entity should disclose information that helps financial statement users evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial statements. Disclosures arising from the adoption of IFRS 12 can be found in Notes 9, 12, and 20.

IV. IFRS 13 *Fair Value Measurement*

IFRS 13 establishes a single source of guidance for all fair value measurements required by other IFRS, clarifies the definition of fair value, and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability, or its own equity instrument at fair value. The Corporation's adoption of IFRS 13, prospectively on Jan. 1, 2013, did not have a material financial impact upon the consolidated financial position or results of operations, however, certain new or enhanced disclosures are required and can be found in Note 13.

V. IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 *Presentation of Financial Statements* issued in June 2011 were intended to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in Other Comprehensive Income (Loss) ("OCI") be grouped on the basis of whether they are subsequently reclassified from OCI to net earnings or not. The Consolidated Statements of Comprehensive Income (Loss) have been reorganized to comply with the required groupings.

VI. IAS 19 *Employee Benefits*

Amendments to IAS 19 *Employee Benefits* are intended to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require the recognition of changes in defined benefit obligations and in fair value of plan assets when they occur, thus eliminating the "corridor approach" previously permitted. All actuarial gains and losses must be recognized immediately through other comprehensive income and the net pension liability or asset recognized at the full amount of the plan deficit or surplus. Additional changes relate to the presentation, into three components, of changes in defined benefit obligations and plan assets: service cost and net interest cost is recognized in net earnings and remeasurements are recognized in other comprehensive income. The net interest cost introduced in these amendments removes the concept of expected return on plan assets that was previously recognized in net earnings.

The Corporation calculates the net interest cost for its defined benefit plans by applying the discount rate at the beginning of the reporting period to the net defined benefit liability at the beginning of the reporting period. An expected return on plan assets is no longer calculated and recognized as part of pension expense. The elimination of the corridor method had no impact as the Corporation has, since adoption of IFRS, recognized actuarial gains and losses in OCI in the period in which they occurred.

On adoption, the Corporation applied the amendments retrospectively. The impacts as at Dec. 31, 2012 and Jan 1, 2012, respectively, were an increase in the cumulative prior periods' pre-tax pension expense of $17 million and $11 million ($12 million and $8 million after-tax, respectively), as a result of the application of the net interest cost requirements.

For the three and six months ended June 30, 2012, Operations, maintenance, and administration expense increased by $2 million and $3 million, respectively, as a result of increased pension expense. Net after-tax actuarial losses on defined benefit plans as reported in OCI decreased by $1 million and $2 million, respectively, and basic and diluted net earnings per share attributable to common shareholders decreased by $0.01 and $0.01, respectively.

VII. Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine ("IFRIC 20")*

IFRIC 20 clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods.

The Corporation recognizes a stripping activity asset for its Highvale mine when all of the following are met: (i) it is probable that the future benefit associated with improved access to the coal reserves associated with the stripping activity will be realized; (ii) the component of the coal reserve to which access has been improved can be identified; and (iii) the costs related to the stripping activity associated with that component can be measured reliably. Costs include those directly incurred to perform the stripping activity as well as an allocation of directly attributable overheads. The resulting stripping activity asset is amortized on a unit-of-production basis over the expected useful life of the identified component that it relates to. The amortization is recognized as a component of the standard cost of coal inventory.

As required by the transitional provision of IFRIC 20, the Interpretation was applied by the Corporation to production stripping costs incurred on or after Jan. 1, 2011, which will be the earliest comparative period presented within the Corporation's annual financial statements for the year ended Dec. 31, 2013. The impacts on the Condensed Consolidated Statements of Financial Position as at Dec. 31, 2012 were to recognize $9 million in costs as a stripping activity asset, increase coal inventory by $2 million, both classified within Inventory, increase Deferred income tax liabilities by $3 million, and decrease Retained deficit by $8 million. The impacts on the Condensed Consolidated Statements of Financial Position as at Jan. 1, 2012 were to recognize $9 million in costs as a stripping activity asset, decrease coal inventory by $2 million, both classified within Inventory, increase Deferred income tax liabilities by $2 million, and increase Retained earnings by $5 million.

The impact of this change in accounting policy on the three and six months ended June 30, 2012 was not material.

VIII. IFRS 7 *Financial Instruments: Disclosures*

Amendments to IFRS 7 include disclosures about all recognized financial instruments that are set off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set off under IAS 32. The resulting disclosures can be found in Note 14.

IX. Annual Improvements 2009-2011

In May 2012, the IASB issued a collection of necessary, non-urgent amendments to several IFRS resulting from its annual improvements process. The amendments, as applicable, have been applied by the Corporation on Jan. 1, 2013. None of the amendments, which are generally technical and narrow in scope, had a material financial impact upon the consolidated financial position or results of operations.

B. Current Accounting Changes

I. Change in Estimates - Useful Lives

During the first quarter, management completed a comprehensive review of the estimated useful lives of the hydro assets, having regard for, among other things, the economic life cycle maintenance program, and existing condition of the assets. As a result, depreciation was reduced by $1 million and $2 million for the three and six months ended June 30, 2013. Pre-tax depreciation expense is expected to be reduced by $5 million for the year ended Dec. 31, 2013 and by $5 million annually thereafter.

II. Leases

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. Property, plant and equipment ("PP&E") under finance leases are initially recognized at their fair value at the inception of the lease, or if lower, at the present value of the minimum lease payments. The corresponding liability is included in the Condensed Consolidated Statements of Financial Position as a finance lease obligation. Lease payments are apportioned between interest expense and reduction of the lease obligation so as to achieve a constant rate of interest on the remaining balance of the liability.

C. Future Accounting Changes

Additional new or amended accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation, are as follows: IFRS 9 *Financial Instruments*, IAS 32 *Financial Instruments: Presentation*, and *Investment Entities* (Amendments to IFRS 10 and 11 and IAS 27). Please refer to Note 3(D) of the Corporation's 2012 annual consolidated financial statements for more information.

3. SUNHILLS MINING LIMITED PARTNERSHIP

Effective Jan. 17, 2013, the Corporation assumed, through its wholly owned SunHills Mining Limited Partnership ("SunHills"), operations and management control of the Highvale Mine from Prairie Mines and Royalty Ltd. ("PMRL"). PMRL employees working at the Highvale Mine were offered employment by SunHills which agreed to assume responsibility for certain pension plan and pension funding obligations, which had been previously funded by the Corporation through the payments made under the PMRL mining contracts. As a result, a pre-tax loss of $29 million was recognized during the first quarter, along with the corresponding liabilities.

The Corporation also entered into finance leases for certain mining equipment that was in use, or committed to, by PMRL for mining operations. As a result, $8 million and $29 million in mining equipment have been capitalized to PP&E and the related finance lease obligations recognized during three and six months ended June 30, 2013. At the end of the lease terms, the Corporation is eligible to purchase the assets, for a nominal amount. The amounts payable under the finance leases are as follows:

As at	**June 30, 2013**	
	Minimum lease payments	**Present value of minimum lease payments**
Within one year	**9**	**8**
Second to fifth years inclusive	**18**	**17**
	27	**25**
Less: interest cost	**2**	**-**
Total finance lease obligation	**25**	**25**

Included in the Condensed Consolidated Statements of Financial Position as:	
Current portion of finance lease obligation	**8**
Non-current finance lease obligation	**17**
	25

4. SUNDANCE UNITS 1 AND 2 ARBITRATION

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of the Corporation's Sundance facility was shut down due to conditions observed in the boilers at both units. On Feb. 8, 2011, the Corporation issued a notice of termination for destruction based on the determination that the units cannot be economically restored to service under the terms of the Power Purchase Arrangement ("PPA"). Due to the uncertainty of the results of the arbitration ruling, the Corporation had been continuing to accrue the capacity payments, net of a provision, and to depreciate the asset.

The matter was heard before an arbitration panel during the second quarter of 2012. On July 20, 2012, the arbitration panel concluded that Unit 1 and Unit 2 were not economically destroyed and the Corporation will restore the facility to service. The panel affirmed that the event met the criteria of force majeure beginning on Nov. 20, 2011 until such time that the units are returned to service.

The pre-tax income statement impact of the ruling that has been recorded under the caption "Sundance Units 1 and 2 arbitration" in Condensed Consolidated Statement of Earnings (loss) is as follows:

Availability incentive penalties	260
Reversal of provision on capacity payments	(64)
Impairment of the units *(Note 8)*	43
Interest	8
Total pre-tax impact (1)	**247**

(1) Related income tax impact is a recovery of $63 million.

5. DISPOSALS

During the three and six months ended June 30, 2013, the Corporation realized a pre-tax gain of $10 million relating to the sale of land.

During the three and six months ended June 30, 2012, the Corporation realized a pre-tax gain of nil and $3 million, respectively, related to the sale of its biomass facility in 2011. The gain resulted from the release of the remaining consideration related to the achievement of the Environmental Attribute Conditions by the purchaser.

6. OPERATING LEASES

Several of the Corporation's PPAs and other long-term contracts meet the criteria of operating leases. Total rental income, including contingent rent, related to these contracts reported in Revenues in the Condensed Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2013, was $54 million (June 30, 2012 - $40 million), and $103 million (June 30, 2012 - $82 million), respectively.

7. EXPENSES BY NATURE

Expenses classified by nature are as follows:

	3 months ended June 30, 2013		3 months ended June 30, 2012 *(Restated)**	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**149**	**-**	125	-
Purchased power	**22**	**-**	6	-
Salaries and benefits	**2**	**66**	1	69
Depreciation	**14**	**-**	10	-
Other operating expenses	**-**	**67**	-	64
Total	**187**	**133**	142	133

	6 months ended June 30, 2013		6 months ended June 30, 2012 *(Restated)**	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**320**	**-**	264	-
Purchased power	**39**	**-**	31	-
Salaries and benefits	**3**	**127**	2	135
Depreciation	**26**	**-**	20	-
Other operating expenses	**-**	**121**	-	126
Total	**388**	**248**	317	261

** See Note 2 for prior period restatements.*

8. ASSET IMPAIRMENT CHARGES

A. Sundance Units 1 and 2

During the three and six months ended June 30, 2012, the Corporation recognized a pre-tax impairment charge of $43 million as a result of the conclusion of the Sundance Units 1 and 2 arbitration. The impairment assessment was based on an estimate of fair value less costs to sell, derived from the cash flows expected to result under the provisions of the PPA, and the estimated costs to return the Units to service (See Note 4).

B. Centralia Thermal

On July 25, 2012, the Corporation signed a long-term agreement for the supply of power from December 2014 until the facility is fully retired in 2025. As a result, the Corporation recognized a pre-tax impairment charge of $347 million included in the Generation Segment during the three and six months ended June 30, 2012. The impairment assessment was based on whether the carrying amount of the Centralia Thermal plant was recoverable based on an estimate of fair value less costs to sell.

In addition to the impairment charge, the Corporation wrote off $169 million of deferred income tax assets as it is no longer probable that sufficient taxable income will be available from the Corporation's U.S. operations, which have been impacted by the Centralia Thermal plant impairment, to allow the benefit associated with the deferred income tax assets to be utilized.

C. Renewables

During the three and six months ended June 30, 2012, the Corporation recognized a pre-tax impairment charge of $18 million related to five assets within the renewables fleet. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs to sell, derived from the long range forecasts and prices evidenced in the market place. The assets were impaired primarily due to expectations regarding lower market prices. The impairment losses were included in the Generation segment.

D. Reversals

The impairment charges and the reduction of the deferred tax asset can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants, and the estimated taxable income to be generated by the Centralia Thermal plant, respectively, improve.

9. INVESTMENTS

The Corporation's investments in joint ventures accounted for using the equity method consist of its investments in CE Generation, LLC ("CE Gen"), Wailuku River Hydroelectric, L.P ("Wailuku"), TAMA Transmission, and CalEnergy, LLC ("CalEnergy").

Summarized financial information on the results of operations and financial position relating to the Corporation's pro-rata interests in CE Gen, Wailuku, TAMA Transmission, and CalEnergy is as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Results of operations				
Revenues	**26**	24	**46**	50
Expenses	**(29)**	(29)	**(53)**	(55)
Proportionate share of net loss	**(3)**	(5)	**(7)**	(5)

Summarized financial information relating to 100 per cent of CE Gen, including adjustments for the application of consistent accounting policies and the Corporation's purchase price adjustments, is as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Revenues	**52**	48	**90**	98
Depreciation and amortization	**20**	22	**43**	43
Interest expense	**5**	6	**10**	12
Income tax recovery	**(4)**	(6)	**(19)**	(16)
Net loss from continuing operations	**(5)**	(9)	**(13)**	(12)
Other comprehensive gain (loss)	**4**	(1)	**-**	(1)
Total comprehensive loss	**(1)**	(10)	**(13)**	(13)
Distributions received	**-**	-	**-**	-

As at	June 30, 2013	Dec. 31, 2012
Current assets	**102**	93
Long-term assets	**677**	675
Current liabilities	**(69)**	(62)
Long-term liabilities	**(392)**	(409)
Net assets	**318**	297
Additional items included above		
Cash and cash equivalents	**17**	27
Current financial liabilities[1]	**(41)**	(35)
Long-term financial liabilities[1]	**(221)**	(233)

(1) Excludes trade and other payables and provisions

A reconciliation of the carrying amount to the Corporation's 50 per cent interest in the CE Gen joint venture is as follows:

As at	June 30, 2013	Dec. 31, 2012
Net assets	**318**	297
Less: minority interest in CE Gen	**(14)**	(14)
Less: 50 per cent of CE Gen's net assets not owned by the Corporation	**(124)**	(116)
Net investment	**180**	167

CE Gen's ability to make distributions to its owners, including the Corporation, is restricted by covenants and conditions, including principal and interest funding deposit requirements, imposed by certain project-related debt agreements.

At June 30, 2013 the carrying amount of the Corporation's net investment in CalEnergy, TAMA Transmission and Wailuku is $5 million (Dec. 31, 2012 - $5 million).

10. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Interest on debt	**58**	58	**118**	114
Capitalized interest	**-**	(1)	**(2)**	(1)
Ineffectiveness on hedges	**-**	2	**-**	2
Interest expense	**58**	59	**116**	115
Accretion of provisions *(Note 19)*	**5**	5	**9**	9
Net interest expense	**63**	64	**125**	124

The Corporation capitalizes interest during the construction phase of growth capital projects. The capitalized interest in 2013 and 2012 related to the New Richmond wind farm.

11. INCOME TAXES

The components of income tax expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Current income tax expense (recovery)	**18**	(5)	**26**	8
Adjustments in respect of current income tax of previous years	**-**	2	**-**	2
Deferred income tax recovery related to the origination and reversal of temporary differences	**(7)**	(98)	**(26)**	(85)
Deferred income tax expense (recovery) resulting from changes in tax rates or laws(1)	**(1)**	7	**(7)**	7
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce current income tax expense	**-**	-	**-**	(14)
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**-**	-	**-**	(10)
Deferred income tax expense arising from the writedown of deferred income tax assets	**-**	169	**-**	169
Income tax expense (recovery)	**10**	75	**(7)**	77

(1) Relates to the impact of adjusting the deferred tax rate to incorporate the Ontario M&P tax credit. Previously, the Corporation had been using the Ontario general corporate tax rate of 11.5 per cent.

Presented in the Condensed Consolidated Statements of Earnings (Loss) as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Current income tax expense (recovery)	**18**	(3)	**26**	(4)
Deferred income tax expense (recovery)	**(8)**	78	**(33)**	81
Income tax expense (recovery)	**10**	75	**(7)**	77

12. NON-CONTROLLING INTERESTS

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest
TransAlta Cogeneration L.P. ("TA Cogen")	49.99% - Stanley Power Inc.
Kent Hills wind farm	17% - Natural Forces Technologies Inc.

Summarized financial information relating to TA Cogen, the subsidiary with a significant non-controlling interest, is as follows:

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Revenues	**76**	63	**157**	147
Net earnings	**16**	8	**35**	33
Total comprehensive income	**19**	10	**47**	20
Amounts attributable to the non-controlling interest:				
Net earnings	**8**	4	**17**	16
Total comprehensive income	**9**	5	**24**	10
Distributions paid to Stanley Power Inc.	**15**	12	**33**	31

As at	June 30, 2013	Dec. 31, 2012
Current assets	**51**	70
Long-term assets	**653**	678
Current liabilities	**(63)**	(75)
Long-term liabilities	**(71)**	(87)
Total equity	**(570)**	(588)
Equity attributable to the non-controlling interest	**(283)**	(290)

13. FINANCIAL INSTRUMENTS

A. Financial Assets and Liabilities - Classification and 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. Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments 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 the Energy Trading and Generation business segments.

The following tables summarize the key factors impacting the fair value of energy trading risk management assets and liabilities by classification level during the six months ended June 30, 2013 and 2012, 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, 2012	-	(63)	3	(1)	79	28	(1)	16	31
Changes attributable to:									
Market price changes on existing contracts	-	(30)	(3)	-	7	6	-	(23)	3
Market price changes on new contracts	-	(1)	-	-	(19)	(15)	-	(20)	(15)
Contracts settled	-	3	-	1	(36)	(7)	1	(33)	(7)
Transfers out of Level III	-	-	-	-	1	(1)	-	1	(1)
Net risk management assets (liabilities) at June 30, 2013	**-**	**(91)**	**-**	**-**	**32**	**11**	**-**	**(59)**	**11**
Additional Level III gain (loss) information:									
Losses recognized in OCI			(3)			-			(3)
Total losses included in earnings before income taxes			-			(9)			(9)
Unrealized losses included in earnings before income taxes relating to net assets held at June 30, 2013			-			(16)			(16)

	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, 2011	-	(90)	(14)	-	287	7	-	197	(7)
Changes attributable to:									
Market price changes on existing contracts	-	10	10	1	20	9	1	30	19
Market price changes on new contracts	-	(1)	-	1	(14)	2	1	(15)	2
Contracts settled	-	8	5	2	(123)	(13)	2	(115)	(8)
Discontinued hedge accounting on certain contracts	-	(28)	-	-	22	6	-	(6)	6
Net risk management assets (liabilities) at June 30, 2012	-	(101)	1	4	192	11	4	91	12
Additional Level III gain (loss) information:									
Gains recognized in OCI			10			-			10
Total gains (losses) included in earnings before income taxes			(5)			11			6
Unrealized losses included in earnings before income taxes relating to net assets held at June 30, 2012			-			(2)			(2)

a. Levels I, II, and III Fair Value Measurements and transfers between Fair Value Levels

i. 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. 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.

ii. 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. Energy Trading includes, in Level II, 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.

iii. Level III

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

Energy Trading 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.

Energy Trading also has various contracts with terms that extend beyond a liquid trading period. As forward price forecasts 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.

Policies and procedures regarding energy trading Level III fair value measurements are determined by the Corporation's Risk Management department, in compliance with the Corporation's 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. Level III fair values are calculated within the Corporation's Energy Trading Risk Management system based on underlying contractual data and 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 Risk Management personnel. 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.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at June 30, 2013 is estimated to be +/- $26 million (Dec. 31, 2012 - $26 million). Fair values are stressed for volumes and prices. The volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Information about the significant unobservable inputs used in determining Level III fair values is as follows:

Description	Fair value as at June 30, 2013	Valuation Technique	Unobservable input	Range
Unit contingent power purchases	8	Historical bootstrap	Price discount	1 - 2 per cent
			Volumetric discount(1)	1 - 8 per cent
Long term power sale	(12)	Historical bootstrap	Illiquid future power prices	$39.80 - $84.51
Coal supply revenue sharing	(8)	Black-scholes	Volumes (MWh)	18 - 24 per cent of capacity
			Illiquid future implied volatilities in MidC power	29 per cent
Unit contingent power sales	25	Black-scholes	Volumetric discount	0 per cent
			Illiquid future implied volatilities in MidC power	40 per cent

(1) A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.

iv. Transfers between Fair Value Levels

Fair value Level transfers can occur where the availability of inputs that are used to determine fair values have changed. A transfer from Level III to Level II occurs where inputs that were not readily observable have become observable during the period. The Corporation's policy is for Level transfers to occur at the end of each period. During the three months ended June 30, 2013, $1 million of fair value was transferred from Level III net risk management assets to Level II net risk management assets. The trade terms of these contracts were originally beyond a liquid trading period where forward price forecasts were not available for the full period of the contract. During the period the contract terms were determined to be within a liquid trading period where observable prices are available.

II. 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 trading transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks.

The following tables summarize the key factors impacting the fair value of other risk management assets and liabilities by classification level during the six months ended June 30, 2013 and 2012, 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, 2012	-	(50)	-	-	1	-	-	(49)	-
Changes attributable to:									
Market price changes on existing contracts	-	68	-	-	1	-	-	69	-
Market price changes on new contracts	-	(1)	-	-	3	-	-	2	-
Contracts settled	-	1	-	-	(1)	-	-	-	-
Net risk management assets at June 30, 2013	**-**	**18**	**-**	**-**	**4**	**-**	**-**	**22**	**-**

	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 liabilities at Dec. 31, 2011	-	(50)	-	-	-	-	-	(50)	-
Changes attributable to:									
Market price changes on existing contracts	-	24	-	-	-	-	-	24	-
Market price changes on new contracts	-	(38)	-	-	-	-	-	(38)	-
Contracts settled	-	34	-	-	-	-	-	34	-
Discontinued hedge accounting on certain contracts	-	1	-	-	(1)	-	-	-	-
Net risk management liabilities at June 30, 2012	-	(29)	-	-	(1)	-	-	(30)	-

a. Level II Fair Value Measurements

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

Level II fair values of other risk management assets and liabilities are determined using valuation techniques, such as discounted cash flow methods. The Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves, credit valuation adjustments, 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.

III. 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] - June 30, 2013	**-**	**4,557**	**-**	**4,557**	**4,460**
Long-term debt[1] - Dec. 31, 2012	-	4,426	-	4,426	4,217

(1) Includes current portion.

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

The book value of other short-term financial assets and liabilities (cash and cash equivalents, 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

An inception gain or loss arises due to differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. The unrealized gain or loss related to Level III financial instruments is deferred in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. At June 30, 2013, the unamortized gain is $5 million (Dec. 31, 2012 - $5 million gain).

14. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	June 30, 2013					Dec. 31, 2012
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	-	-	-	99	99	198
Long-term	-	1	-	42	43	59
Total energy trading risk management assets	-	1	-	141	142	257
Other						
Current	-	13	-	4	17	3
Long-term	-	3	8	-	11	10
Total other risk management assets	-	16	8	4	28	13
Risk management liabilities						
Energy trading						
Current	-	32	-	69	101	141
Long-term	-	60	-	29	89	70
Total energy trading risk management liabilities	-	92	-	98	190	211
Other						
Current	1	1	-	-	2	26
Long-term	-	4	-	-	4	36
Total other risk management liabilities	1	5	-	-	6	62
Net energy trading risk management assets (liabilities)	**-**	**(91)**	**-**	**43**	**(48)**	46
Net other risk management assets (liabilities)	**(1)**	**11**	**8**	**4**	**22**	(49)
Net total risk management assets (liabilities)	**(1)**	**(80)**	**8**	**47**	**(26)**	(3)

Additional information on derivative instruments has been presented on a net basis below.

I. Netting Arrangements

Information about the Corporation's financial management assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at	June 30, 2013				Dec. 31, 2012			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**474**	**73**	**(488)**	**(99)**	522	331	(452)	(317)
Gross amounts set-off	**(194)**	**(7)**	**194**	**7**	(252)	(186)	252	186
Net amounts as presented in the Condensed Consolidated Statements of Financial Position[1]	**280**	**66**	**(294)**	**(92)**	270	145	(200)	(131)

(1) Excludes credit reserves.

II. Hedges

a. Cash Flow Hedges

i. Energy Trading Risk Management

Certain of TransAlta's hedging relationships had previously been de-designated and deemed ineffective for accounting purposes. The hedges were in respect of power production and the associated gains remain in Accumulated Other Comprehensive Income (Loss) ("AOCI") until the underlying production occurs or until such time that the production has been assessed as highly probable not to occur. No gains related to these previously de-designated hedges were reclassified to earnings during the three and six months ended June 30, 2013 (June 30, 2012 - nil and $75 million pre-tax gain, respectively).

As at June 30, 2013, cumulative gains of $4 million, related to these and other cash flow hedges that were de-designated and no longer meet the criteria for hedge accounting, continued to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or if the forecasted transactions are assessed as highly probable not to occur.

ii. Cash Flow Hedge Impacts

Over the next 12 months ended June 30, 2014, the Corporation estimates that $35 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors.

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 17(B) of the 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 Trading Segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

VaR at June 30, 2013 associated with the Corporation's proprietary energy trading activities was $3 million (Dec. 31, 2012 - $2 million).

b. Commodity Price Risk - Generation

The Generation Segment utilizes various commodity contracts and other financial instruments to manage the commodity price risk associated with its electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. VaR at June 30, 2013 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $7 million (Dec. 31, 2012 - $5 million). VaR at June 30, 2013 associated with positions and economic hedges that do not meet hedge accounting requirements was $12 million (Dec. 31, 2012 - $9 million).

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the distribution, by credit rating, of certain financial assets as at June 30, 2013:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	90	10	**100**
Risk management assets	98	2	**100**

The Corporation's maximum exposure to credit risk at June 30, 2013, without taking into account collateral held or right of set-off, is represented by the carrying amounts of accounts receivable and risk management assets as per the Condensed Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one counterparty for commodity trading operations and hedging, excluding the California market receivables (Refer to Note 36 of the 2012 annual consolidated financial statements), and including the fair value of open trading positions, net of any collateral held, at June 30, 2013 was $20 million (Dec. 31, 2012 - $25 million).

At June 30, 2013, TransAlta had two counterparties whose net settlement positions accounted for greater than 10 per cent of the total trade receivables outstanding. The Corporation has evaluated the risk of default related to these counterparties to be minimal.

III. Liquidity Risk

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

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

	2013	2014	2015	2016	2017	2018 and thereafter	Total
Accounts payable and accrued liabilities	374	-	-	-	-	-	374
Debt[1]	320	209	681	29	1,097	2,119	4,455
Energy trading risk management (assets) liabilities	29	(26)	10	16	8	11	48
Other risk management (assets) liabilities	(15)	1	1	(1)	-	(8)	(22)
Interest on long-term debt[2]	112	197	164	158	144	830	1,605
Dividends payable	57	-	-	-	-	-	57
Total	**877**	**381**	**856**	**202**	**1,249**	**2,952**	**6,517**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2014 and 2017.

(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 June 30, 2013, the Corporation had posted collateral of $85 million (Dec. 31, 2012 - $85 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 $51 million of collateral to its counterparties based upon the value of the derivatives at June 30, 2013.

15. RESTRICTED CASH

The Corporation has $7 million of cash and cash equivalents at June 30, 2013 (Dec. 31, 2012 - $2 million) that is not available for general use, all of which relates to Project Pioneer.

16. INVENTORY

Inventory held in the normal course of business includes coal, emission credits, and natural gas, and is valued at the lower of cost and net realizable value. Inventory held for trading, which also includes natural gas and purchased emission credits, is valued at fair value less costs to sell.

The classifications are as follows:

As at	**June 30, 2013**	Dec. 31, 2012 *(Restated)**
Coal	**87**	78
Deferred stripping costs	**24**	9
Natural gas	**4**	2
Purchased emission credits	**7**	4
Total	**122**	93

** See Note 2 for prior period restatements.*

For the three and six months ended June 30, 2013, coal inventory at the Corporation's Centralia plant was written down by $2 million (June 30, 2012 - $8 million) and $16 million (June 30, 2012 - $42 million), respectively, to its net realizable value.

17. PROPERTY, PLANT, AND EQUIPMENT

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

	Land	Thermal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[(1)]	Total
As at Dec. 31, 2012	75	2,874	996	2,004	517	342	236	7,044
Additions	-	-	-	-	-	282	-	282
Additions - finance lease *(Note 3)*	-	-	-	-	29	-	-	29
Depreciation	-	(129)	(50)	(45)	(28)	-	(6)	(258)
Revisions and additions to decommissioning and restoration costs	-	6	(4)	5	5	-	-	12
Retirement of assets	-	(4)	(1)	(2)	(1)	-	-	(8)
Change in foreign exchange rates	1	18	(9)	-	2	1	2	15
Transfers	-	55	23	220	17	(333)	18	-
As at June 30, 2013	76	2,820	955	2,182	541	292	250	7,116

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

During the three and six months ended June 30, 2013, the Corporation capitalized nil and $2 million (June 30, 2012 - $1 million) of interest to PP&E at a weighted average rate of nil and 5.46 per cent (June 30, 2012 - 5.32 and 5.34 per cent), respectively.

18. OTHER ASSETS

The components of other assets are as follows:

As at	June 30, 2013	Dec. 31, 2012
Deferred licence fees	**19**	21
Project development costs	**35**	35
Deferred service costs	**19**	19
Long-term prepaids	**19**	5
Keephills Unit 3 transmission deposit	**6**	7
Other	**2**	3
Total other assets	**100**	90

19. DECOMMISSIONING AND OTHER PROVISIONS

The change in decommissioning and other provision balances is outlined below:

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2012	262	8	42	312
Liabilities incurred in period	2	-	16	18
Liabilities settled in period	(13)	(4)	-	(17)
Accretion *(Note 10)*	9	-	-	9
Revisions in estimated cash flows *(Note 17)*	4	-	1	5
Revisions in discount rates *(Note 17)*	7	-	-	7
Reversals	-	(2)	(11)	(13)
Change in foreign exchange rates	4	-	1	5
	275	2	49	326
Less: current portion	**18**	**2**	**4**	**24**
Balance, June 30, 2013	**257**	**-**	**45**	**302**

The restructuring provision relates to the Corporation's 2012 restructuring of resources as part of its ongoing strategy to continuously improve operational excellence and accelerate growth.

Other provisions include an amount related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2018.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

20. LONG-TERM DEBT

A. Debt and Letters of Credit

The amounts outstanding are as follows:

As at	**June 30, 2013**			Dec. 31, 2012		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**1,096**	**1,096**	**2.4%**	950	950	2.4%
Debentures	**841**	**851**	**6.6%**	839	851	6.6%
Senior notes(3)	**2,116**	**2,096**	**5.6%**	2,017	1,990	5.6%
Non-recourse(4)	**375**	**380**	**5.9%**	375	380	5.9%
Other	**32**	**32**	**6.4%**	36	36	6.5%
	4,460	**4,455**		4,217	4,207	
Less: recourse current portion	**(523)**	**(523)**		(606)	(606)	
Less: non-recourse current portion	**(1)**	**(1)**		(1)	(1)	
Total long-term debt	**3,936**	**3,931**		3,610	3,600	

(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. Includes U.S.$300 million at June 30, 2013 (Dec. 31, 2012 - U.S.$300 million).

(3) U.S. face value at June 30, 2013 - U.S.$2.0 billion (Dec. 31, 2012 - U.S.$2.0 billion).

(4) Includes U.S.$20 million at June 30, 2013 (Dec. 31, 2012 - U.S.$20 million).

TransAlta has a total of $2.1 billion (Dec. 31, 2012 - $2.0 billion) of committed credit facilities, of which $0.7 billion (Dec. 31, 2012 - $0.8 billion) is not drawn, and is available as of June 30, 2013, subject to customary borrowing conditions. In May 2013, the Corporation completed a renewal of its four-year revolving $1.5 billion committed syndicated credit facility and extended its maturity by one year to 2017. In June 2013, the U.S.$300 million bilateral credit facility was renewed for a four-year term to 2017. The Corporation also has $240 million in committed bilateral credit facilities, all of which matures in the fourth quarter of 2014. In addition to the $0.7 billion available under the credit facilities, TransAlta also has $60 million of available cash and cash equivalents.

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at June 30, 2013 was $341 million (Dec. 31, 2012 - $336 million) with no (Dec. 31, 2012 - nil) amounts exercised by third parties under these arrangements.

B. Restrictions

Debt agreements of $11 million related to the Windsor plant, owned by the Corporation’s TA Cogen subsidiary, include principal and interest funding provisions that restrict the Corporation’s ability to access funds generated by the operations of the plant. The Corporation has provided a letter of credit in the amount of the funding requirements, thereby permitting it to access the funds.

Debentures of $340 million issued by the Corporation’s Canadian Hydro Developers, Inc. subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewables assets. Accordingly, the Corporation is not able to use such proceeds for other purposes.

21. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

The components of deferred credits and other long-term liabilities are as follows:

As at	June 30, 2013	Dec. 31, 2012
Deferred coal revenues	**51**	51
Defined benefit obligations	**221**	220
Long-term incentive accruals	**8**	15
Other	**20**	15
Total deferred credits and other long-term liabilities	**300**	301

22. COMMON SHARES

A. Issued and Outstanding

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

A reconciliation of changes in common shares is as follows:

	3 months ended June 30				6 months ended June 30			
	2013		2012		**2013**		2012	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount	**Common shares** *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**258.4**	**2,783**	224.6	2,295	**254.7**	**2,730**	223.6	2,274
Issued under the dividend reinvestment and share purchase plan	**3.7**	**53**	2.4	42	**7.4**	**106**	3.3	62
Issued under the PSOP	**-**	**-**	-	1	**-**	**-**	0.1	2
	262.1	**2,836**	227.0	2,338	**262.1**	**2,836**	227.0	2,338
Amounts receivable under Employee Share Purchase Plan	**-**	**(4)**	-	(3)	**-**	**(4)**	-	(3)
Issued and outstanding, end of period	**262.1**	**2,832**	227.0	2,335	**262.1**	**2,832**	227.0	2,335

B. Dividends

The following table summarizes the common share dividends declared or paid within the six months ended June 30:

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares
2013					
Apr. 22, 2013	July 1, 2013	0.29	76	21(1)	55
Jan. 28, 2013	Apr. 1, 2013	0.29	75	22	53
Oct. 24, 2012	Jan. 1, 2013	0.29	73	20	53
2012					
Apr. 25, 2012	July 1, 2012	0.29	66	18	48
Jan. 25, 2012	Apr. 1, 2012	0.29	65	23	43
Oct. 27, 2011	Jan. 1, 2012	0.29	65	45	20

(1) Dividends were paid out on June 28, 2013.

The Corporation suspended the Premium Dividend™ component of its Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan") following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remain effective in accordance with their current terms, discussed more fully in Note 28(C) of the most recent annual consolidated financial statements.

On July 1, 2013, 4.2 million common shares were issued for dividends reinvested.

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

23. PREFERRED SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

Preferred shares outstanding are as follows:

As at	**June 30, 2013**		Dec. 31, 2012			
Cumulative Redeemable Rate Reset First Preferred Shares	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount	**Dividend rate per share** *($)*	**Redemption price per share** *($)*
Series A	12	293	12	293	1.15	25.00
Series C	11	269	11	269	1.15	25.00
Series E	9	219	9	219	1.25	25.00
Issued and outstanding, end of period	**32**	**781**	32	781		

B. Dividends

The following table summarizes the preferred share dividends declared or paid within the six months ended June 30:

		Series A		**Series C**		**Series E**	
Date declared	**Payment date**	**Dividend per share** *($)*	**Total dividends**	**Dividend per share** *($)*	**Total dividends**	**Dividend per share** *($)*	**Total dividends**
2013							
Apr. 22, 2013	June 30, 2013	0.2875	4	0.2875	3	0.3125	3
Jan. 28, 2013	March 31, 2013	0.2875	3	0.2875	3	0.3125	3
2012							
Apr. 25, 2012	June 30, 2012	0.2875	4	0.2875	3	-	-
Jan. 25, 2012	March 31, 2012	0.2875	3	0.3844(1)	4	-	-

(1) Includes dividends of $0.0969 per share ($1 million in total) for the period from Nov. 29, 2011 to Dec. 31, 2011, which were accrued at Dec. 31, 2011.

24. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of, and changes in, AOCI are presented below:

	2013	2012 (Restated)*
Currency translation adjustment		
Opening balance, Jan. 1	**(38)**	(28)
Gains on translating net assets of foreign operations	**32**	13
Losses on financial instruments designated as hedges of foreign operations, net of tax(1)	**(29)**	(11)
Balance, June 30	**(35)**	(26)
Cash flow hedges		
Opening balance, Jan. 1	**(37)**	(28)
Losses on derivatives designated as cash flow hedges, net of tax(2)	**(19)**	(31)
Balance, June 30	**(56)**	(59)
Employee future benefits		
Opening balance, Jan. 1	**(61)**	(38)
Net actuarial gains (losses) on defined benefit plans, net of tax(3)	**11**	(22)
Balance, June 30	**(50)**	(60)
Accumulated other comprehensive loss	**(141)**	(145)

** See Note 2 for prior period restatements.*

(1) Net of income tax recovery of 4 for the six months ended June 30, 2013 (2012 - 2 recovery).

(2) Net of income tax expense of nil for the six months ended June 30, 2013 (2012 - 25 expense).

(3) Net of income tax expense of 4 for the six months ended June 30, 2013 (2012 - nil).

25. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal 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.

26. COMMITMENTS

During March 2013, the New Richmond wind farm commenced operations and as such, the 15 year long-term service agreement for repairs and maintenance became effective. The future payments over the term of the agreement are approximately $42 million.

27. SEGMENT DISCLOSURES

A. Reported Segment Earnings (Loss)

Each business segment assumes responsibility for its operating results to operating income.

3 months ended June 30, 2013	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**528**	**14**	**-**	**542**
Fuel and purchased power	**187**	**-**	**-**	**187**
Gross margin	**341**	**14**	**-**	**355**
Operations, maintenance, and administration	**111**	**6**	**16**	**133**
Depreciation and amortization	**125**	**-**	**6**	**131**
Inventory writedown	**2**	**-**	**-**	**2**
Reversal of restructuring charges	**(1)**	**-**	**(1)**	**(2)**
Taxes, other than income taxes	**8**	**-**	**-**	**8**
Intersegment cost allocation	**3**	**(3)**	**-**	**-**
Operating income (loss)	**93**	**11**	**(21)**	**83**
Finance lease income	**12**	**-**	**-**	**12**
Equity loss	**(3)**	**-**	**-**	**(3)**
Gain on sale of assets	**-**	**-**	**10**	**10**
Foreign exchange gain				**5**
Net interest expense				**(63)**
Earnings before income taxes				**44**

3 months ended June 30, 2012 *(Restated)**	Generation	Energy Trading	Corporate	Total
Revenues	409	(11)	-	398
Fuel and purchased power	142	-	-	142
Gross margin	267	(11)	-	256
Operations, maintenance, and administration	106	7	20	133
Depreciation and amortization	134	-	5	139
Asset impairment charges	365	-	-	365
Inventory writedown	8	-	-	8
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	4	(4)	-	-
Operating loss	(357)	(14)	(25)	(396)
Finance lease income	2	-	-	2
Equity loss	(5)	-	-	(5)
Sundance Units 1 and 2 arbitration				(247)
Other income				1
Foreign exchange loss				(3)
Net interest expense				(64)
Loss before income taxes				(712)

** See Note 2 for prior period restatements.*

6 months ended June 30, 2013	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,051**	**31**	**-**	**1,082**
Fuel and purchased power	**388**	**-**	**-**	**388**
Gross margin	**663**	**31**	**-**	**694**
Operations, maintenance, and administration	**205**	**14**	**29**	**248**
Depreciation and amortization	**247**	**-**	**11**	**258**
Inventory writedown	**16**	**-**	**-**	**16**
Reversal of restructuring charges	**(1)**	**-**	**(1)**	**(2)**
Taxes, other than income taxes	**15**	**-**	**-**	**15**
Intersegment cost allocation	**7**	**(7)**	**-**	**-**
Operating income (loss)	**174**	**24**	**(39)**	**159**
Finance lease income	**23**	**-**	**-**	**23**
Equity loss	**(7)**	**-**	**-**	**(7)**
Gain on sale of assets	**-**	**-**	**10**	**10**
Foreign exchange gain				**4**
Loss on assumption of pension obligations				**(29)**
Net interest expense				**(125)**
Earnings before income taxes				**35**

6 months ended June 30, 2012 *(Restated)**	Generation	Energy Trading	Corporate	Total
Revenues	1,036	6	-	1,042
Fuel and purchased power	317	-	-	317
Gross margin	719	6	-	725
Operations, maintenance, and administration	205	14	42	261
Depreciation and amortization	258	-	10	268
Asset impairment charges	365	-	-	365
Inventory writedown	42	-	-	42
Taxes, other than income taxes	14	-	-	14
Intersegment cost allocation	7	(7)	-	**-**
Operating loss	(172)	(1)	(52)	(225)
Finance lease income	4	-	-	4
Equity loss	(5)	-	-	(5)
Gain on sale of assets	3	-	-	3
Sundance Units 1 and 2 arbitration				(247)
Other income				1
Foreign exchange loss				(9)
Net interest expense				(124)
Loss before income taxes				(602)

** See Note 2 for prior period restatements.*

Included in the Generation Segment results for the three and six months ended June 30, 2013 are $5 million (June 30, 2012 - $5 million) and $12 million (June 30, 2012 - $13 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

B. Selected Condensed Consolidated Statements of Financial Position Information

Total segment assets	Generation	Energy Trading	Corporate	Total
June 30, 2013	**8,956**	**195**	**305**	**9,456**
Dec. 31, 2012 *(Restated)**	8,994	262	206	9,462

** See Note 2 for prior period restatements.*

C. 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 June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**131**	139	**258**	268
Depreciation included in fuel and purchased power *(Note 7)*	**14**	10	**26**	20
Other	**-**	-	**-**	2
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**145**	149	**284**	290

28. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended June 30		6 months ended June 30	
	2013	2012	**2013**	2012
Source (use) of cash:				
Accounts receivable	**17**	(26)	**159**	78
Prepaid expenses	**(12)**	2	**(34)**	(13)
Income taxes receivable	**-**	-	**(3)**	(14)
Inventory	**(29)**	(13)	**(30)**	(15)
Accounts payable and accrued liabilities	**(75)**	237	**(112)**	147
Decommissioning and other provisions	**-**	(53)	**-**	(41)
Income taxes payable	**6**	(15)	**4**	(16)
Change in non-cash operating working capital	**(93)**	132	**(16)**	126

29. FORMATION OF TRANSALTA RENEWABLES INC.

On June 26, 2013, the Corporation announced the launch and creation of TransAlta Renewables Inc. ("TransAlta Renewables"), an entity which will provide investors with the opportunity to invest directly in a highly contracted portfolio of renewable power generation facilities. The Corporation will be the sponsor and manager of TransAlta Renewables and will provide TransAlta Renewables with its initial asset base. A preliminary prospectus qualifying the initial public offering of TransAlta Renewables common shares to the public (the "Offering") was filed on June 26, 2013.

The Corporation intends to transfer 1,112 net megawatts of highly contracted wind and hydro power generation assets to TransAlta Renewables upon completion of the Offering. The Corporation will be the primary source of growth of TransAlta Renewables' portfolio of renewable power generation assets, by providing TransAlta Renewables with the opportunity to purchase, or participate in the development of, renewable power generation facilities with stable, long-term, contracted cash flows. The creation of TransAlta Renewables provides the Corporation with a focused vehicle for pursuing and funding growth opportunities in the renewable power generation sector. Upon completion of the Offering, the Corporation will retain control of and fully consolidate TransAlta Renewables.

Completion of the Offering is subject to, and conditional upon, the receipt of all necessary approvals, including regulatory approvals. The Offering is expected to close in August 2013.

30. SUBSEQUENT EVENTS

Centralia Thermal

On July 25, 2012, the Corporation announced that it entered into an 11-year agreement to provide electricity from the Centralia Thermal plant to Puget Sound Energy ("PSE"). The agreement was approved, with conditions, by the Washington Utilities and Transportation Commission ("WUTC") on Jan. 9, 2013. On Jan. 23, 2013, it was announced that PSE had filed a petition for reconsideration of certain conditions within the decision issued by the WUTC. On June 25, 2013, regulatory approval was confirmed by the WUTC and as of July 5, 2013, the contract is in effect in accordance with the WUTC's terms and conditions.

SUPPLEMENTAL INFORMATION

		June 30, 2013	Dec. 31, 2012
Closing market price (TSX) ($)		**14.41**	15.12
Price range for the last 12 months (TSX) ($)	High	**16.86**	21.37
	Low	**12.91**	14.11
Debt to invested capital (%)		**57.2**	55.6
Debt to invested capital excluding non-recourse debt (%)(1)		**55.0**	53.3
Debt to invested capital including finance lease obligation and non-recourse debt (%)		**57.3**	55.6
Return on equity attributable to common shareholders (%)		**4.5**	(23.7)
Comparable return on equity attributable to common shareholders(1), (2) (%)		**6.3**	4.5
Return on capital employed(2) (%)		**5.3**	(3.1)
Comparable return on capital employed(1), (2) (%)		**6.2**	5.3
Cash dividends per share(2) ($)		**1.16**	1.16
Price to comparable earnings ratio(2) (times)		**25.3**	30.2
Earnings coverage(2) (times)		**1.6**	(1.2)
Dividend payout ratio based on net earnings(2) (%)		**293.9**	(44.1)
Dividend payout ratio based on comparable earnings(1), (2) (%)		**212.4**	231.6
Dividend payout ratio based on funds from operations(1), (2), (3) (%)		**35.6**	34.7
Dividend yield(2) (%)		**8.0**	7.7
Adjusted cash flow to debt(2), (3) (%)		**18.6**	19.0
Adjusted cash flow to interest coverage(2), (3) (times)		**4.5**	4.4

(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.

(3) The December 2012 ratios have been adjusted for the impact of the Sundance Units 1 and 2 arbitration.

RATIO FORMULAS

Debt to invested capital = long-term debt including current portion - cash and cash equivalents / long-term debt including current portion + non-controlling interests + equity attributable to shareholders - cash and cash equivalents

Return on equity attributable to common shareholders = net earnings attributable to common shareholders or earnings on a comparable basis / average 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 / average invested capital excluding AOCI

Price to comparable earnings ratio = current period's closing market price / comparable earnings per share

Earnings coverage = net earnings attributable to common shareholders + income taxes + net interest expense / interest on debt - interest income

Dividend payout ratio = common share dividends / net earnings attributable to common shareholders or earnings on a comparable basis or funds from operations

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

Adjusted cash flow to debt = cash flow from operating activities before changes in working capital / average total debt - average cash and cash equivalents

Adjusted cash flow to interest coverage = cash flow from operating activities before changes in working capital + interest on debt - interest income - capitalized interest / interest on debt - 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.

British Thermal Units (Btu) - A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

Capacity - The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Derate - To lower the rated electrical capability of a power generating facility or unit.

Force Majeure - Literally means “major 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.

Geothermal Plant - A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

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.

Heat Rate - A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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.

Net Maximum Capacity - The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Power Purchase Arrangement (PPA) - A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA Buyers.

Renewable Power - Power generated from renewable terrestrial mechanisms including wind, geothermal, and solar with regeneration.

Spark Spread - A measure of gross margin per MW (sales price less cost of natural gas).

Supercritical Combustion Technology: The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Turbine - A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround: Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

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

Uprate - To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR) - A measure to manage earnings exposure from energy trading activities.

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