TRANSALTA CORPORATION
FIRST QUARTER REPORT FOR 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three months ended March 31, 2014 and 2013, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2013 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation', and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. Certain financial measures included in this MD&A do not have a standardized meaning as prescribed by IFRS. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. See the Non-IFRS Measures section of this MD&A for additional information. This MD&A is dated April 28, 2014. 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. For this MD&A, we have further split what is reported as our Generation business segment into the various fuel types to provide additional information to our readers. 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

First Quarter Highlights

Consolidated Highlights

	3 months ended March 31	
	2014	2013
Revenues	**775**	540
Comparable EBITDA[1]	**310**	268
Net earnings (loss) attributable to common shareholders	**49**	(11)
Comparable net earnings attributable to common shareholders[1]	**47**	32
Funds from operations[1]	**238**	193
Cash flow from operating activities	**279**	256
Free cash flow[1]	**139**	114
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.04)
Comparable net earnings per share[1]	**0.17**	0.12
Funds from operations per share[1]	**0.88**	0.75
Free cash flow per share[1]	**0.51**	0.44
Dividends paid per common share	**0.18**	0.29

As at	**March 31, 2014**	Dec. 31, 2013[2]
Total assets	**9,565**	9,624
Total long-term liabilities	**4,735**	5,348

- Comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA") for 2014 increased $42 million to $310 million due primarily to higher power and gas prices in the northeast driving strong results from our Energy Trading Segment, steady operational performance across the Generation Segment, and a full quarter's contribution from wind units commissioned or acquired in 2013. As a result, funds from operations ("FFO") increased $45 million compared to the prior year to $238 million.
- Comparable net earnings were $47 million ($0.17 net earnings per share), up from $32 million ($0.12 net earnings per share) in 2013. Higher depreciation and amortization, net interest expense, income tax expense, and income attributable to non-controlling interests partially offset the increase in EBITDA.
- Reported net earnings attributable to common shareholders were $49 million ($0.18 net earnings per share), up $60 million from a net loss of $11 million ($0.04 net loss per share) in 2013. The change is driven by the increase in comparable EBITDA of $42 million and the one time after-tax loss on assumption of pension obligations of $22 million in the prior year.

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(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.

Strategic Highlights

- Named preferred bidder for the South Hedland Power Project to build, own, and operate a 150 megawatt ("MW") combined cycle gas power station in Western Australia.
- Secondary offering of TransAlta Renewables Inc. ("TransAlta Renewables") shares for gross proceeds of $136.2 million.
- Entered into an agreement to sell our 50 per cent ownership of CE Generation LLC ("CE Gen") and Wailuku Holding Company, LLC ("Wailuku") for proceeds of U.S.$193.5 million. We expect the sale of CE Gen to close in the second quarter.
- Started construction with our joint venture partner of a $178 million natural gas pipeline to our Solomon power station. We hold a 43 per cent interest in the joint venture.

Operational Financial Results

Comparable EBITDA is as follows:

	3 months ended March 31	
	2014	2013
Availability (%)[1]	**91.5**	91.5
Production (GWh)[1]	**12,067**	10,644
Comparable EBITDA		
Generation Segment		
Canadian Coal	**94**	99
U.S. Coal	**17**	12
Gas	**82**	85
Wind	**62**	50
Hydro	**19**	24
Total Generation Segment	**274**	270
Energy Trading Segment	**49**	14
Corporate Segment	**(13)**	(16)
Total comparable EBITDA	**310**	268

- Canadian Coal: In 2014, comparable EBITDA was $94 million compared to $99 million in 2013. The decrease in comparable EBITDA is primarily due to higher gas consumption as a result of opacity issues at certain facilities and the derating of Keephills Unit 3.
- U.S. Coal: Comparable EBITDA increased to $17 million in 2014 compared to $12 million in 2013. The increase in comparable EBITDA is primarily due to higher market prices in the Pacific Northwest.
- Gas: Comparable EBITDA decreased by $3 million to $82 million, primarily due contract curtailments and unrealized mark-to-market losses on certain forward contracts.
- Wind: Comparable EBITDA for wind improved by $12 million in 2014 to $62 million, primarily due to the acquisition of Wyoming Wind, a full quarter operations at New Richmond, and higher wind volumes in Eastern Canada.
- Hydro: Comparable EBITDA decreased by $5 million to $19 million, primarily as a result of lower prices in Alberta for power and ancillary services.

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

- Energy Trading Segment: Our Energy Trading business showed an improvement in comparable EBITDA of $35 million to $49 million in 2014 by capitalizing on high power and gas prices through our ability to optimize our energy marketing assets, capitalize on arbitrage opportunities, and serve customer demands during extraordinarily volatile market conditions caused by extreme weather events during the quarter in the northeast.
- Corporate Segment: The Corporate Segment incurred operations, maintenance, and administration ("OM&A") expenses of $13 million in 2014 compared to $16 million in 2013. The reduction in OM&A is primarily due a change in the way in which certain overhead cost allocations are made within the organization, partially offset by an increase in compensation costs.

AVAILABILITY & PRODUCTION

Availability for the three months ended March 31, 2014 was comparable to the same period in 2013.

Production for the three months ended March 31, 2014 increased 1,423 gigawatt hours ("GWh") compared to the same period in 2013, primarily due to Sundance Units 1 and 2 returning to service, lower economic dispatching at Centralia Thermal, the acquisition of Wyoming Wind, and a full quarter of operations at New Richmond, partially offset by an unplanned outage at our Mississauga facility and derating of Keephills Unit 3.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

FFO for the three months ended March 31, 2014 increased $45 million compared to the same period in 2013 to $238 million, primarily due to the increase in comparable EBITDA.

Free cash flow for the three months ended March 31, 2014 increased $25 million compared to the same period in 2013 to $139 million due to an increase in FFO, partially offset by increased sustaining capital expenditures and distributions paid to subsidiaries' non-controlling interests.

SIGNIFICANT EVENTS

Australia Natural Gas Pipeline

On Jan. 15, 2014, we announced the formation of an unincorporated joint venture named Fortescue River Gas Pipeline Joint Venture. The first project of this new joint venture will be to build, own, and operate a $178 million natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station. We hold a 43 per cent interest in the joint venture through a wholly owned subsidiary. In addition to our portion of the pipeline cost, an additional $10 million in plant retrofitting costs will also be incurred as part of the project, which will be recoverable over time through increased lease payments.

Executive Leadership Team Appointments

On March 18, 2014, we announced three senior leadership appointments that will enhance our objectives of operational excellence from the base business and growth. Brett Gellner was appointed to the role of Chief Investment Officer, responsible for leading all growth aspects of the Corporation. Donald Tremblay joined TransAlta as Chief Financial Officer, effective March 31, 2014, and Wayne Collins has accepted a role taking on the leadership accountabilities of our Coal and Mining Operations.

Fort McMurray Transmission Project

On Jan. 17, 2014, we announced that our strategic partnership with MidAmerican Transmission, TAMA Transmission LP ("TAMA Transmission"), which was formed on May 9, 2013, successfully qualified to participate as a proponent in the Fort McMurray West 500 kilovolt Transmission Project. The Alberta Electric System Operator ("AESO") announced its selection of a short-list of companies, identifying that TAMA Transmission will participate in the next stage of its competitive process for the project.

Sale of CE Gen, the Blackrock Development Project, CalEnergy, LLC, and Wailuku

On Feb. 20, 2014, we announced an agreement to sell our 50 per cent ownership of CE Gen, the Blackrock Development Project ("Blackrock"), CalEnergy, LLC ("CalEnergy"), and Wailuku to MidAmerican Renewables for proceeds of U.S.$193.5 million. MidAmerican Renewables holds the other 50 per cent interest in CE Gen, CalEnergy, Blackrock, and Wailuku. With the exception of Wailuku, we expect to complete the transaction during the second quarter.

Sundance Unit 6 Agreement

On Feb. 19, 2014, we reached an agreement with the Power Purchase Arrangement ("PPA") Buyer related to the dispute on Sundance Unit 6. There are no material impacts to the financial statements as a result of the agreement.

Settlement of California Proceedings

On March 18, 2014, TransAlta entered into a settlement to resolve outstanding claims related to the 2000 – 2001 power crisis in the State of California. The settlement, which is subject to approval by the U.S. Federal Energy Regulatory Commission ("FERC"), provides for the payment by TransAlta of U.S.$52 million in two equal payments over a 12-month period and the transfer of approximately U.S.$97 million of accounts receivable owed to TransAlta from the California Independent System Operator and now-defunct California Power Exchange. The impact of the settlement is consistent with the accrual we made for the year ended Dec. 31, 2013.

Proceedings Before the Alberta Utilities Commission

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the Alberta Utilities Commission (the "AUC") alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. TransAlta has denied the MSA's allegations in their entirety. In a separate, but related matter, on Feb. 21, 2014, TransAlta filed a complaint with the AUC concerning the conduct of the MSA in relation to its investigation of TransAlta and its failure to consult with market participants prior to making certain decisions on permitted offer behaviour. The MSA's application and TransAlta's complaint are presently before the AUC.

SUBSEQUENT EVENTS

South Hedland Power Project

On April 15, 2014, we announced that we had been named the preferred bidder for the South Hedland Power Project in Western Australia. Subject to the finalization of necessary contracts and approvals that will take place during the second quarter, the project would see TransAlta build, own, and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The investment is estimated at approximately AUD$550 million. The power station is expected to be delivering power in 2016, with full commissioning in 2017. The development will be fully contracted under 25 year agreements with Horizon Power, a state utility company and Fortescue Metals Group Ltd., a mining company. The project may be expanded to accommodate additional customers at later dates.

Secondary Offering of TransAlta Renewables Inc. Shares

In April 2014, we completed the previously announced secondary offering of 10,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. In addition, the over-allotment option granted to the syndicate of underwriters, led by CIBC and RBC Capital Markets, was partially exercised for an additional 1,000,000 common shares, also at a price of $11.40 per common share.

The offering resulted in gross proceeds to TransAlta of $136.2 million. We will use the net proceeds from the offering to reduce indebtedness, to fund growth, and for general corporate purposes. Following completion of the offering, TransAlta owns approximately 70.3 per cent of the common shares of TransAlta Renewables.

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 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 2013 Annual MD&A.

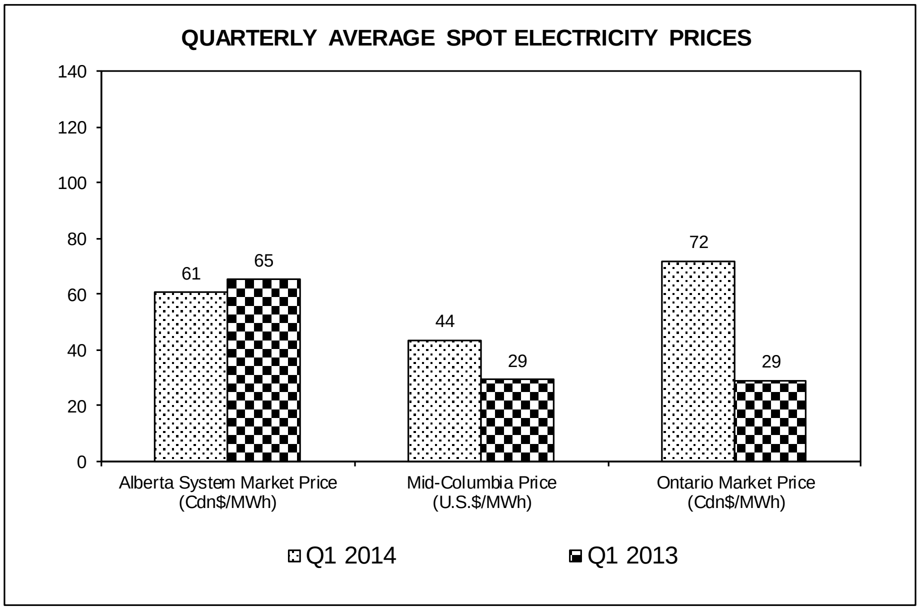
Contracted Cash Flows

During the first quarter of 2014, approximately 88 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 2014 are approximately $55 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 2013 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 months ended March 31, 2014 and 2013 in our three major markets are shown in the following graph.



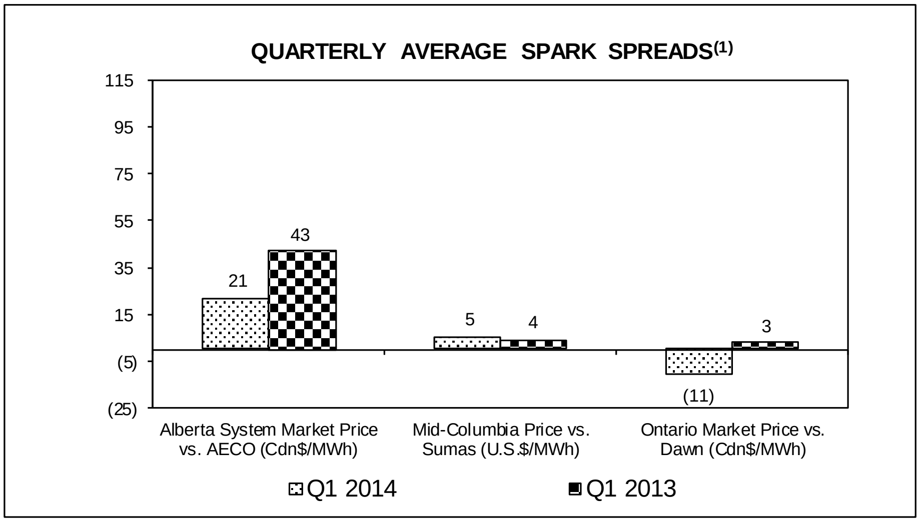
For the three months ended March 31, 2014, average spot prices in Alberta decreased compared to the same period in 2013, primarily due to an increase in supply as a result of Sundance Units 1 and 2 returning to service. In the Pacific Northwest, average spot prices increased due to higher natural gas prices, particularly in February. Average spot prices in Ontario for the three months ended March 31, 2014 increased compared to the same period in 2013 due to extreme cold weather across the entire northeast, which led to higher natural gas prices and increased demand.

In 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation and fewer planned maintenance outages across the market. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle higher than in 2013 due to marginally higher natural gas prices. In Ontario, prices for the balance of the year are expected to be higher than 2013 due to higher natural gas prices.

Spark Spreads

Please refer to the Business Environment section of our 2013 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 months ended March 31, 2014 and 2013 in our three major markets are shown in the following graph.



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

For the three months ended March 31, 2014, average spark spreads decreased in Alberta compared to the same period in 2013 due to lower prices resulting from an increase in supply as a result of Sundance Units 1 and 2 returning to service and higher natural gas prices. In the Pacific Northwest, average spark spreads were comparable to the same period in 2013. Average spark spreads decreased in Ontario compared to the same period in 2013. High natural gas prices throughout the first quarter of 2014 reduced spark spreads in the market. High gas prices can reduce calculated average spark spreads because many of the hourly prices are not set by natural gas generators. During these low-priced hours, the high natural gas price makes natural gas generators unprofitable.

DISCUSSION OF SEGMENTED RESULTS

We have three business segments: Generation, Energy Trading, and Corporate.

Generation: *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. Electricity sales generated by our Commercial and Industrial group are assumed to be sourced from TransAlta's production and have been included in the Generation Segment on a net basis.*

The full capacity of the facilities in which we have a share of ownership is 10,144 MW[(1)]. At March 31, 2014, our generating assets had 9,092 MW of gross generating capacity[(1)] in operation (8,497 MW[(1)] net ownership interest). The following information excludes assets that are accounted for using the equity method, which are discussed separately within this discussion of the Generation Segment.

The results of the Generation Segment are as follows:

	3 months ended March 31, 2014			3 months ended March 31, 2013		
	Reported	**Comparable adjustments[(2)]**	**Comparable total**	Reported	Comparable adjustments	Comparable total
Availability (%)[(3)]	**91.4**	**-**	**91.4**	91.7	-	91.7
Production (GWh)[(3)]	**11,753**	**-**	**11,753**	10,250	-	10,250
Gross installed capacity (MW)[(1), (3)]	**9,092**	**-**	**9,092**	8,388	-	8,388
Net installed capacity (MW)[(1), (3)]	**8,497**	**-**	**8,497**	8,007	-	8,007
Revenues	**710**	**(7)**	**703**	523	41	564
Fuel and purchased power	**335**	**-**	**335**	201	-	201
Gross margin	**375**	**(7)**	**368**	322	41	363
Operations, maintenance, and administration	**112**	**(4)**	**108**	92	-	92
Inventory writedown	**4**	**-**	**4**	14	-	14
Taxes, other than income taxes	**7**	**-**	**7**	7	-	7
Finance lease income	**(12)**	**(1)**	**(13)**	(11)	(1)	(12)
Intersegment cost allocation	**3**	**-**	**3**	4	-	4
Gain on sale of property, plant, and equipment	**-**	**-**	**-**	-	(1)	(1)
Mine depreciation	**-**	**(15)**	**(15)**	-	(11)	(11)
EBITDA	**261**	**13**	**274**	216	54	270
Depreciation and amortization	**129**	**15**	**144**	122	12	134
Other	**-**	**1**	**1**	-	1	1
Operating income	**132**	**(3)**	**129**	94	41	135

(1) We measure capacity as net maximum capacity (see Glossary of Key Terms 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. Gross capacity reflects the basis of consolidation of underlying assets, while net capacity deducts capacity attributable to non-controlling interests in these assets.

(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) Availability, production, and installed capacity include assets under generation operations and finance leases.

Coal: *TransAlta owns and operates coal-fired facilities and related mining operations in Canada and the U.S. Coal revenues and overall profitability are derived from the availability and production of electricity. 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 2013 Annual MD&A.*

Canadian Coal

	3 months ended March 31	
	2014	2013
Availability (%)	**87.1**	85.4
Production (GWh)	**6,249**	5,275
Gross installed capacity (MW)	**3,771**	3,211
Net installed capacity (MW)	**3,576**	3,016
Revenues	**254**	228
Fuel and purchased power	**122**	94
Comparable gross margin(1)	**132**	134
Operations, maintenance, and administration	**49**	43
Taxes, other than income taxes	**3**	3
Intersegment cost allocation	**1**	1
Gain on sale of property, plant, and equipment	**-**	(1)
Mine depreciation	**(15)**	(11)
Comparable EBITDA(1)	**94**	99
Depreciation and amortization	**76**	69
Comparable operating income(1)	**18**	30
Sustaining capital expenditures:		
Routine capital	**10**	6
Mining equipment and land purchases	**5**	8
Finance leases	**2**	-
Planned major maintenance(2)	**28**	23
Total	**45**	37

Production for the three months ended March 31, 2014 increased 974 GWh compared to the same period in 2013 primarily due to Sundance Units 1 and 2 returning to service. The return to service of Sundance Units 1 and 2 impacted our revenue, fuel and purchased power, and OM&A expenses.

For the three months ended March 31, 2014, comparable EBITDA decreased by $5 million compared to the same period in 2013, due to higher gas consumption as a result of opacity issues at certain coal facilities, derating of the higher margin Keephills Unit 3, and an increase in OM&A as a result of the way in which certain overhead cost allocations are made within the organization, partially offset by lower coal costs and favourable contract pricing.

Depreciation and amortization for the three months ended March 31, 2014 increased by $7 million compared to the same period in 2013 due to an increased asset base, primarily related to Sundance Units 1 and 2 returning to service.

(1) 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.

(2) Consists of three planned outages in 2014 and one planned outage in 2013.

For the three months ended March 31, 2014, the increase in sustaining capital expenditures compared to 2013 is mainly due to an increase in planned outages. These results include the effects of the Keephills Unit 2 force majeure outage that commenced on Jan. 31, 2014. The Unit returned to service on March 13, 2014.

U.S. Coal

	3 months ended March 31	
	2014	2013
Availability (%)	**94.9**	98.3
Production (GWh)	**2,116**	1,678
Gross and net installed capacity (MW)	**1,340**	1,340
Revenues	**106**	71
Fuel and purchased power	**71**	31
Comparable gross margin	**35**	40
Operations, maintenance, and administration	**13**	11
Inventory writedown	**4**	14
Taxes, other than income taxes	**-**	1
Intersegment cost allocation	**1**	2
Comparable EBITDA	**17**	12
Depreciation and amortization	**14**	13
Comparable operating income (loss)	**3**	(1)
Sustaining capital expenditures:		
Routine capital	**-**	2
Planned major maintenance	**1**	1
Total	**1**	3

Production for the three months ended March 31, 2014 increased 438 GWh compared to the same period in 2013 due to higher pricing resulting in lower economic dispatching, partially offset by higher unplanned outages.

For the three months ended March 31, 2014, comparable EBITDA increased by $5 million compared to the same period in 2013, primarily due to higher market prices.

Gas: *TransAlta owns and operates natural gas-fired facilities in Canada, the U.S., and Australia. Gas revenues and overall profitability are derived from the availability and production of electricity and steam. 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 2013 Annual MD&A.*

	3 months ended March 31	
	2014	2013
Availability (%)	**96.1**	97.7
Production (GWh)(1)	**2,008**	2,133
Gross installed capacity (MW)(1), (2)	**1,779**	1,779
Net installed capacity (MW)(1), (2)	**1,618**	1,618
Revenues	**232**	167
Fuel and purchased power	**136**	71
Comparable gross margin	**96**	96
Operations, maintenance, and administration	**25**	21
Taxes, other than income taxes	**1**	1
Intersegment cost allocation	**1**	1
Finance lease income	**(13)**	(12)
Comparable EBITDA	**82**	85
Depreciation and amortization	**27**	27
Other	**1**	1
Comparable operating income	**54**	57
Sustaining capital expenditures:		
Routine capital	**3**	2
Planned major maintenance	**4**	4
Total	**7**	6

Production for the three months ended March 31, 2014 decreased 125 GWh compared to the same period in 2013 primarily due to contract curtailments and an unplanned outage at our Mississauga facility. The economic impact of the unplanned outage was largely mitigated by the resale of gas in the market.

For the three months ended March 31, 2014, comparable EBITDA decreased by $3 million compared to the same period in 2013, due to contract curtailments and unrealized mark-to-market losses on certain forward contracts.

(1) Includes production capacity for Fort Saskatchewan and Solomon power stations, which have been accounted for as finance leases.

(2) The Centralia gas plant is currently not in operation. We are currently assessing the generation needs of the region and the financial feasibility of bringing the plant back into operation.

Renewables: *TransAlta owns and operates hydro and wind facilities in Canada and the U.S. Renewable revenues and overall profitability are derived from the availability of water and wind resources and the production of electricity, 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 2013 Annual MD&A.*

Wind

	3 months ended March 31	
	2014	2013
Availability (%)	**94.2**	93.9
Production (GWh)	**1,012**	788
Gross installed capacity (MW)	**1,289**	1,145
Net installed capacity (MW)	**1,070**	1,120
Revenues	**80**	64
Fuel and purchased power	**4**	4
Comparable gross margin	**76**	60
Operations, maintenance, and administration	**12**	9
Taxes, other than income taxes	**2**	1
Comparable EBITDA	**62**	50
Depreciation and amortization	**21**	19
Comparable operating income	**41**	31
Sustaining capital expenditures:		
Routine capital	**-**	1
Planned major maintenance	**1**	1
Total	**1**	2

Production for the three months ended March 31, 2014 increased 224 GWh compared to the same period in 2013 due to the acquisition of Wyoming Wind, a full quarter of operations at New Richmond, and higher wind volumes in Eastern Canada.

For the three months ended March 31, 2014, comparable EBITDA increased by $12 million compared to the same period in 2013, due to the new wind farms and higher wind volumes in Eastern Canada.

Depreciation and amortization for the three months ended March 31, 2014 increased by $2 million compared to the same period in 2013 due to a full quarter of operations at New Richmond and the acquisition of Wyoming Wind.

Hydro

	3 months ended March 31	
	2014	2013
Production (GWh)	**368**	376
Gross installed capacity (MW)	**913**	913
Net installed capacity (MW)	**893**	913
Revenues	**31**	34
Fuel and purchased power	**2**	1
Comparable gross margin	**29**	33
Operations, maintenance, and administration	**9**	8
Taxes, other than income taxes	**1**	1
Comparable EBITDA	**19**	24
Depreciation and amortization	**6**	6
Comparable operating income	**13**	18
Sustaining capital expenditures:		
Routine capital	**3**	1
Total	**3**	1

Production for the three months ended March 31, 2014 decreased by 8 GWh compared to the same period in 2013 due to unfavourable market conditions.

Comparable EBITDA decreased by $5 million for the three months ended March 31, 2014 compared to the same period in 2013 primarily as a result of lower market pricing in Alberta for power and ancillary services.

Equity Investments

Our interests in the CE Gen and Wailuku joint ventures are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 852 MW of gross generating capacity (396 MW net ownership interest).

As outlined in the Significant Events section of this MD&A, we have entered into agreements to sell our interests in CE Gen and Wailuku. Our interest in CalEnergy is also being sold with CE Gen. While we continue to be the beneficial owner of our 50 per cent interests in CE Gen, CalEnergy, and Wailuku until the proposed sales close, these investments are no longer accounted for using the equity method effective March 1, 2014. The equity method was used to account for the results of these joint ventures for the months of January and February 2014, but ceased with classification of these investments as assets held for sale in compliance with IFRS requirements.

The table below summarizes key operational information adjusted to reflect our interest in these investments:

	2 months ended Feb. 28, 2014	3 months ended March 31, 2013
Availability (%)	**97.1**	86.9
Production (GWh):		
Gas	**127**	140
Renewables	**187**	254
Total production	**314**	394

Availability for the two months ended Feb. 28, 2014 increased compared to the three months ended March 31, 2013 due to lower planned outages.

Production for the two months ended Feb. 28, 2014 decreased by 80 GWh compared to the three months ended March 31, 2013. After the removal of the March 2013 portion of production, the production for the two months ended Feb. 28, 2014 increased by 26 GWh compared to the same period in 2013. The increase was as a result of lower planned outages, partially offset by higher market curtailments.

Equity loss for the two months ended Feb. 28, 2014 was nil compared to $4 million for the three months ended March 31, 2013. The reduction of the loss is primarily due to lower planned outages in the two months ended Feb. 28, 2014 compared to the same period in 2013.

Our investment in TAMA Transmission continues to be accounted for using the equity method.

Energy Trading: *Derives revenue and earnings from the wholesale marketing and 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 2013 Annual MD&A for further discussion on VaR.*

Energy Trading markets our production through short-term and long-term contracts, ensures cost effective and reliable fuel supply, and seeks to capture margin upside within dynamic market conditions. We leverage our core marketing capabilities by also serving third party customers' energy supply and marketing needs.

Our marketing commitments are backed by our own supply and through the acquisition of third party supply and proprietary marketing assets, such as transmission, transportation, and storage rights. In the course of managing our portfolio, we actively seek to take advantage of our knowledge of physical power and fuel markets to capture incremental arbitrage margins.

All activities are managed within our core markets and within our low to moderate risk profile. Direct marketing of our own generation is reported in the Generation Segment results. All activities indirectly related to our assets and all other marketing activities are reported in the Energy Trading Segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2013 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 March 31	
	2014	2013
Revenues and comparable gross margin	**65**	17
Operations, maintenance, and administration	**19**	7
Intersegment cost allocation	**(3)**	(4)
Comparable EBITDA and comparable operating income	**49**	14

Extreme weather events caused unprecedented gas and power commodity price volatility in eastern markets during the quarter. Natural gas prices in New England and power prices in NEPool averaged more than double those for the comparative period last year. These conditions positively impacted our ability to optimize our portfolio of generation, transportation, transmission, and storage assets. We also capitalized on low risk arbitrage opportunities brought about by extreme market volatility. We expect the Energy Trading gross margin to return to more normal levels in the $10 to $15 million range per quarter for the balance of year.

For the three months ended March 31, 2014, Energy Trading comparable EBITDA increased by $35 million to $49 million. The increase in comparable gross margin was partially offset by higher OM&A expense due to higher compensation costs driven by the strong results.

Corporate: *Our Generation and Energy Trading segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, procurement, 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 March 31	
	2014	2013
Operations, maintenance, and administration and comparable EBITDA	**13**	16
Depreciation and amortization	**6**	5
Comparable operating loss	**(19)**	(21)
Sustaining capital expenditures:		
Routine capital	**7**	2
Total	**7**	2

For the three months ended March 31, 2014, OM&A expense decreased by $3 million compared to 2013, primarily due to a change in the way in which certain overhead cost allocations are made within the organization, partially offset by an increase in compensation costs.

Routine capital expenditures for the three months ended March 31, 2014 increased compared to 2013 primarily, as a result of an increase in corporate information technology costs.

NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended March 31	
	2014	2013
Interest on debt	**61**	60
Capitalized interest	**-**	(2)
Interest expense	**61**	58
Accretion of provisions	**5**	4
Net interest expense	**66**	62

The increase in net interest expense for the three months ended March 31, 2014, compared to the same period in 2013, is primarily due to lower capitalized interest and unfavourable foreign exchange impacts.

INCOME TAXES

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

	3 months ended March 31	
	2014	2013
Earnings (loss) before income taxes	**91**	(9)
Income attributable to non-controlling interests	**(15)**	(10)
Equity loss	**-**	4
Impacts associated with certain de-designated and ineffective hedges	**(7)**	41
Loss on assumption of pension obligations	**-**	29
Other non-comparable items	**4**	-
Earnings attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**73**	55
Income tax expense (recovery)	**18**	(17)
Income tax (expense) recovery related to impacts associated with certain de-designated and ineffective hedges	**(2)**	14
Income tax recovery related to changes in corporate income tax rates	**-**	6
Income tax recovery related to loss on assumption of pension obligations	**-**	7
Income tax recovery related to other non-comparable items	**1**	-
Income tax expense excluding non-comparable items	**17**	10
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items (%)	**23**	18

The income tax expense excluding non-comparable items for the three months ended March 31, 2014 increased compared to the same period in 2013 due to higher comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The effective tax rate on earnings attributable to TransAlta shareholders, excluding non-comparable items for the three months ended March 31, 2014, increased compared to the same period in 2013 due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three months ended March 31, 2014 increased $5 million compared to the same period in 2013, primarily due to earnings at TransAlta Renewables, which was formed as a separate public entity in August 2013. As at March 31, 2014, public shareholders owned 19.3 per cent of TransAlta Renewables.

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 months ended March 31, 2014 and 2013. 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 and that these are still effective economic hedges. 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.

Other adjustments to earnings, such as those included in the earnings on a comparable basis calculation, 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.

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.

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.

A reconciliation of comparable results to reported results is as follows:

	3 months ended March 31, 2014			3 months ended March 31, 2013		
	Reported	**Comparable adjustments**	**Comparable total**	Reported	Comparable adjustments	Comparable total
Revenues	**775**	**(7)** [(1)]	**768**	540	41 [(1)]	581
Fuel and purchased power	**335**	**-**	**335**	201	-	201
Gross margin	**440**	**(7)**	**433**	339	41	380
Operations, maintenance, and administration	**144**	**(4)** [(2)]	**140**	115	-	115
Inventory writedown	**4**	**-**	**4**	14	-	14
Taxes, other than income taxes	**7**	**-**	**7**	7	-	7
Finance lease income reclass	**(12)**	**(1)** [(3)]	**(13)**	(11)	(1) [(3)]	(12)
Gain on sale of property, plant, and equipment	**-**	**-**	**-**	-	(1) [(6)]	(1)
Mine depreciation reclass	**-**	**(15)** [(4)]	**(15)**	-	(11) [(4)]	(11)
EBITDA	**297**	**13**	**310**	214	54	268
Depreciation and amortization	**135**	**15** [(4)]	**150**	127	12 [(7)]	139
Finance lease income reclass	**-**	**1** [(3)]	**1**	-	1 [(3)]	1
Operating income	**162**	**(3)**	**159**	87	41	128
Equity loss	**-**	**-**	**-**	(4)	-	(4)
Foreign exchange loss	**(5)**	**-**	**(5)**	(1)	-	(1)
Loss on assumption of pension obligations	**-**	**-**	**-**	(29)	29 [(8)]	-
Earnings before interest and taxes	**157**	**(3)**	**154**	53	70	123
Net interest expense	**66**	**-**	**66**	62	-	62
Income tax expense (recovery)	**18**	**(1)** [(5)]	**17**	(17)	27 [(5)]	10
Net earnings (loss)	**73**	**(2)**	**71**	8	43	51
Non-controlling interests	**15**	**-**	**15**	10	-	10
Net earnings (loss) attributable to TransAlta shareholders	**58**	**(2)**	**56**	(2)	43	41
Preferred share dividends	**9**	**-**	**9**	9	-	9
Net earnings (loss) attributable to common shareholders	**49**	**(2)**	**47**	(11)	43	32
Weighted average number of common shares outstanding in the period	**270**		**270**	258		258
Net earnings (loss) per share attributable to common shareholders	**0.18**		**0.17**	(0.04)		0.12

(1) Impacts associated with certain de-designated and ineffective hedges.

(2) Flood-related maintenance costs.

(3) Decrease in finance lease receivable.

(4) Mine depreciation that is included in fuel and purchased power for presentation purposes.

(5) Net tax effect of all non-comparable items.

(6) Gain on sale of PP&E that is included in depreciation and amortization for presentation purposes.

(7) Total adjustments for gain on sale of PP&E and mine depreciation.

(8) Non-comparable item.

Funds from Operations, Free Cash Flow, Funds from Operations per Share, and Free Cash Flow per Share

Presenting these items 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. During the fourth quarter of 2013, we adjusted the calculation of free cash flow to be calculated as FFO less sustaining capital expenditures, dividends paid on preferred shares, and distributions paid to subsidiaries' non-controlling interests. FFO per share and free cash flow per share are calculated as follows using the weighted average number of common shares outstanding during the period:

	3 months ended March 31	
	2014	2013
Cash flow from operating activities	**279**	256
Payment of restructuring costs	**-**	4
Timing of payments related to assumption of pension obligations	**-**	9
Decrease in finance lease receivable	**1**	1
Change in non-cash operating working capital balances	**(42)**	(77)
FFO	**238**	193
Deduct:		
Sustaining capital expenditures	**(64)**	(51)
Dividends paid on preferred shares	**(9)**	(9)
Distributions paid to subsidiaries' non-controlling interests	**(26)**	(19)
Free cash flow	**139**	114
Weighted average number of common shares outstanding in the period	**270**	258
FFO per share	**0.88**	0.75
Free cash flow per share	**0.51**	0.44

A reconciliation of comparable EBITDA to FFO is as follows:

	3 months ended March 31	
	2014	2013
Comparable EBITDA	**310**	268
Realized gain from risk management activities	**5**	-
Interest expense	**(61)**	(58)
Provisions	**(2)**	(7)
Current income tax expense	**(8)**	(8)
Realized foreign exchange gain	**4**	3
Decommissioning and restoration costs settled	**(3)**	(5)
Payment of restructuring costs	**-**	4
Timing of payments related to assumption of pension obligations	**-**	9
Other non-cash items	**(7)**	(13)
FFO	**238**	193

FINANCIAL POSITION

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2013 to March 31, 2014:

	Increase/ (Decrease)	Primary factors explaining change
Accounts receivable	(81)	Timing of customer receipts
Prepaid expenses	27	Prepayment of annual insurance premiums, royalties, and service agreements
Assets held for sale	211	Transfer of CE Gen, Wailuku, and Blackrock from investments and other long-term assets
Investments	(192)	Transfer of CE Gen and Wailuku under equity investments to assets held for sale
Finance lease receivable (current and long-term)	12	Favourable changes in foreign exchange rates
Property, plant, and equipment, net	(22)	Depreciation for the period partially offset by additions and favourable changes in foreign exchange rates
Deferred income tax assets	(10)	Net deferred income tax expense
Risk management assets (current and long-term)[1]	(11)	Price movements and changes in underlying positions and settlements
Dividends payable	(32)	Reduction of quarterly dividend
Long-term debt (including current portion)	(33)	Reduction of borrowings under credit facility partially offset by unfavourable changes in foreign exchange rates
Decommissioning and other provisions (current and long-term)	11	Fluctuations in period end discount rates
Risk management liabilities (current and long-term)[1]	(14)	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	16	Net earnings for the period partially offset by declared dividends

FINANCIAL INSTRUMENTS

Refer to *Note 19* of the notes to the audited consolidated financial statements within our 2013 Annual Report and *Note 7* of our interim condensed consolidated financial statements as at and for the three months ended March 31, 2014 for details on Financial Instruments. Refer to the Risk Management section of our 2013 Annual Report and *Note 8* 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, 2013.

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.

(1) After giving effect to the $160 million reduction in risk management assets and liabilities as at Dec. 31, 2013, as described in the Current Accounting Changes section of this MD&A.

We also have various contracts with terms that extend beyond five years. As forward market prices are not available for the full period of these contracts, the value of these contracts must be derived by reference to a forecast that is based on a combination of external and internal fundamental modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for specified prices with counterparties that we believe to be creditworthy.

At March 31, 2014, total Level III financial instruments had a net asset carrying value of $33 million (Dec. 31, 2013 - $66 million net asset).

As at March 31, 2014, cumulative gains of $4 million related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2014 compared to the same period in 2013:

3 months ended March 31	**2014**	2013	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**42**	27	
Provided by (used in):			
Operating activities	**279**	256	Increase in cash earnings of $58 million, partially offset by a decrease in the change in working capital of $35 million
Investing activities	**(105)**	(150)	Decrease in additions to PP&E and intangibles of $55 million and an increase in investing non-cash working capital balances of $10 million, partially offset by an increase in realized losses on financial instruments of $14 million and a negative impact of $6 million related to changes in collateral received from or paid to counterparties
Financing activities	**(180)**	(84)	An increase in repayments of borrowings under credit facilities of $83 million, an increase in common share cash dividends of $30 million, and an increase in distributions paid to subsidiaries' non-controlling interests of $7 million, partially offset by realized gains on financial instruments of $25 million
Translation of foreign currency cash	**1**	1	
Cash and cash equivalents, end of period	**37**	50	

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, availability under our long-term credit facilities, and long-term debt or equity issued under our Canadian and U.S. shelf registrations. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling interests partners, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.3 billion as at March 31, 2014 compared to $4.3 billion as at Dec. 31, 2013.

Credit Facilities

At March 31, 2014, we had a total of $2.1 billion (Dec. 31, 2013 - $2.1 billion) of committed credit facilities, of which $0.9 billion (Dec. 31, 2013 - $0.9 billion) is not drawn and is available, subject to customary borrowing conditions. At March 31, 2014, the $1.2 billion (Dec. 31, 2013 - $1.2 billion) of credit utilized under these facilities was comprised of actual drawings of $0.8 billion (Dec. 31, 2013 - $0.8 billion) and letters of credit of $0.4 billion (Dec. 31, 2013 - $0.4 billion).

In addition to the $0.9 billion available under the credit facilities, we have $37 million of available cash.

Share Capital

On April 28, 2014, we had 271.8 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 March 31, 2014, we had 270.4 million (March 31, 2013 - 258.4 million) common shares issued and outstanding. At March 31, 2014, we had 32.0 million (Dec. 31, 2013 - 32.0 million) first preferred shares issued and outstanding.

We issue common shares for the reinvestment of dividends, for cash proceeds, or upon exercise of stock options and other share-based payment plans.

During the three months ended March 31, 2014, 2.1 million (March 31, 2013 - 3.7 million) common shares were issued under the Dividend Reinvestment and Optional Common Share Purchase Plan (the “Plan”) for $28 million (March 31, 2013 - $53 million).

Letters of Credit and Cash Collateral

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At March 31, 2014, we provided letters of credit totalling $427 million (Dec. 31, 2013 - $370 million) and cash collateral of $26 million (Dec. 31, 2013 - $20 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.

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”) and sulphur dioxide (“SO_2”) 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 in an effort 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. Subsequently, on Sept. 20, 2013, the EPA issued draft regulations for new coal-fired plants that, if adopted, would require new coal plants to achieve GHG emissions of no more than 1,100 pounds per MWh of carbon dioxide (significantly below current average emissions for coal-fired plants) in order to be approved. These regulations are expected to be finalized by mid-2014. These proposed regulations do not currently have an impact on our operations. Standards for existing units are under development and will be issued in draft form by June 1, 2014 for finalization by mid-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. Furthermore, the U.S. Supreme Court has agreed to review a challenge to the EPA’s right to regulate GHG emissions from stationary sources like power plants, so the future of this regulation is uncertain.

2014 OUTLOOK

Business Environment

Power Prices

In 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation and fewer planned maintenance outages across the market. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle higher than in 2013 due to marginally higher natural gas prices. In Ontario, prices for the balance of the year are expected to be higher than 2013 due to higher natural gas prices.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. We are in discussions with the Alberta government in an effort 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 such regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of our 2013 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.

Effective January 2013, direct deliveries of power to the California Independent System Operator were subject to Cap and Trade Regulations established by the California Air Resource Board. We continue to monitor our GHG inventory into California.

In Australia, the carbon tax implemented in July 2012 remains in place. However, on Nov. 13, 2013, the then elected Liberal government introduced legislation to repeal the carbon tax by July 2014, and replace it with a Direct Action plan that would fund industry for actions to reduce emissions. The legislation has not yet been passed. While TransAlta's gas-fired operations are subject to the tax, all related costs are passed on to contracted customers.

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

Economic Environment

In 2014, we expect slow to moderate growth in all 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 first quarter of 2014. 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 primarily due to the commencement of operations at our Solomon power station in Australia. Prior to the effect of any economic dispatching, overall production is expected to increase in 2014 compared to 2013 due to Sundance Units 1 and 2 returning to service, lower planned and unplanned outages, the commencement of commercial operations at our Solomon power station, and the acquisition of Wyoming Wind. Overall availability is expected to be in the range of 88 to 90 per cent in 2014.

Contracted Cash Flows

As a result of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the 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 first quarter of 2014, approximately 88 per cent of our 2014 capacity was contracted. The average prices of our short-term physical and financial contracts for 2014 are approximately $55 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. Coal costs for 2014, on a standard cost per tonne basis, are expected to be seven to nine per cent lower than 2013 due to Sundance Units 1 and 2 operating for a full year and the benefits realized from insourcing operational accountability from Prairie Mines and Royalty Ltd. at the Highvale Mine during 2013.

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 2014 is expected to increase between one to three 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 are recognized in net earnings.

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

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

Energy 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 2014 objective is for Energy Trading to contribute between $80 million and $100 million in gross margin for the year as markets return to more normal volatility for the remainder of the year.

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 foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2014 is expected to be higher than in 2013 due to a higher proportion of fixed-rate debt, which has a higher interest rate than variable rate debt, 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 2013 Annual MD&A, are based on the current economic environment and outlook. Under 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 2014, 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

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

	Total Project		**2014**			
	Estimated spend	**Spent to date[1]**	**Estimated spend**	**Spent to date[1]**	**Target completion date**	**Details**
Project						
Australia natural gas pipeline[2]	86	11	86	11	Q1 2015	270 kilometer pipeline to supply natural gas to our Solomon power station in Western Australia
Transmission	10	-	10	-	Q4 2014	Regulated transmission that receives a return on investment
Hydro life extension	15 - 20	2	15 - 20	2	Q4 2014	Generator replacement and turbine runner improvements to extend the life of selected plants
Total	**111 - 116**	**13**	**111 - 116**	**13**		

(1) Represents amounts spent as of March 31, 2014.

(2) Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable.

Sustaining and Productivity Expenditures

For 2014, our estimate for total sustaining 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	110 - 115	23
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	45 - 50	5
Finance leases	Payments related to mining equipment under finance leases	5 - 10	2
Planned major maintenance	Regularly scheduled major maintenance	175 - 190	34
Total sustaining expenditures		**335 - 365**	**64**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	10 - 15	2
Total sustaining and productivity expenditures		**345 - 380**	**66**

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 2014 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2014	Spent to date(1)
Capitalized	120 - 130	55 - 60	175 - 190	34
Expensed	-	0 - 5	0 - 5	-
	120 - 130	55 - 65	175 - 195	34

	Coal	Gas and Renewables	Total	Lost to date(1)
GWh lost	2,200 - 2,210	400 - 410	2,600 - 2,620	10

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, dividends reinvested 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) As of March 31, 2014.

CURRENT ACCOUNTING CHANGES

Inception Gains and Losses

We restated the Condensed Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Condensed Consolidated Statement of Financial Position were immaterial. Refer to *Note 7(C)* in our interim condensed consolidated financial statements as at and for the three months ended March 31, 2014 for further information on inception gains and losses.

IAS 32 Financial Instruments: Presentation

On Jan. 1, 2014, we adopted the amendments to IAS 32 *Financial Instruments: Presentation*. There was no impact of adopting the IAS 32 amendments on the condensed consolidated financial statements.

IAS 36 Impairment of Assets

On Jan. 1, 2014, we adopted the amendments to the disclosure requirements of IAS 36 *Impairment of Assets*. The amended disclosure requirements did not have an impact on the condensed consolidated financial statements.

Comparative Figures

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

FUTURE ACCOUNTING CHANGES

Accounting standards that have been previously issued by the International Accounting Standards Board ("IASB") but are not yet effective, and have not been applied include: IFRS 9 *Financial Instruments*. In February 2014, the IASB indicated that IFRS 9 will be effective for annual periods beginning on or after Jan. 1, 2018. We continue to assess the impact of adopting this standard. Please refer to the Future Accounting Changes section of our 2013 Annual MD&A for more information.

SELECTED QUARTERLY INFORMATION

	Q2 2013	Q3 2013	Q4 2013	**Q1 2014**
Revenue	542	623	587	**775**
Net earnings (loss) attributable to common shareholders	15	(9)	(66)	**49**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.06	(0.03)	(0.25)	**0.18**
Comparable net earnings per share	0.03	0.15	0.00	**0.17**

	Q2 2012	Q3 2012	Q4 2012	Q1 2013
Revenue	398	522	646	540
Net earnings (loss) attributable to common shareholders	(798)	56	39	(11)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(3.52)	0.24	0.15	(0.04)
Comparable net earnings (loss) per share	(0.10)	0.18	0.22	0.12

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,* as amended ("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 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 March 31, 2014, 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 or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management’s experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “anticipate”, “intend”, “plan”, “project”, “foresee”, “potential”, “enable”, “continue”, or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to our business and anticipated future financial performance including, for example: the timing and the completion and commissioning of projects under development, including major projects, and their attendant costs; expectations regarding the AESO’s plans for resolving regional constraints on Alberta’s transmission system; 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; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our expectations relating to the FERC’s approval of our California settlement and the outcome of proceedings before the AUC; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; expectations for the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewals of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; the estimated contribution of Energy Trading activities to gross margin; and expectations relating to the performance of TransAlta Renewables’ assets.

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 and our ability to carry out the repairs in a cost-effective manner or timely manner; 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, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions; the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives; and the satisfactory closing of CE Gen, Blackrock, CalEnergy, and Wailuku. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2013 Annual MD&A and under the heading “Risk Factors” in our 2014 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 March 31	
Unaudited	**2014**	2013
Revenues	**775**	540
Fuel and purchased power	**335**	201
Gross margin	**440**	339
Operations, maintenance, and administration	**144**	115
Depreciation and amortization	**135**	127
Inventory writedown	**4**	14
Taxes, other than income taxes	**7**	7
Operating income	**150**	76
Finance lease income	**12**	11
Equity loss *(Note 3)*	**-**	(4)
Net interest expense *(Note 4)*	**(66)**	(62)
Foreign exchange loss	**(5)**	(1)
Loss on assumption of pension obligations	**-**	(29)
Earnings (loss) before income taxes	**91**	(9)
Income tax expense (recovery) *(Note 5)*	**18**	(17)
Net earnings	**73**	8
Net earnings (loss) attributable to:		
TransAlta shareholders	**58**	(2)
Non-controlling interests	**15**	10
	73	8
Net earnings (loss) attributable to TransAlta shareholders	**58**	(2)
Preferred share dividends *(Note 12)*	**9**	9
Net earnings (loss) attributable to common shareholders	**49**	(11)
Weighted average number of common shares outstanding in the period *(millions)*	**270**	258
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.04)

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2014**	2013
Net earnings	**73**	8
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**(5)**	7
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax[2]	**-**	1
Total items that will not be reclassified subsequently to net earnings	**(5)**	8
Gains on translating net assets of foreign operations	**53**	25
Losses on financial instruments designated as hedges of foreign operations, net of tax[3]	**(47)**	(21)
Gains on derivatives designated as cash flow hedges, net of tax[4]	**13**	14
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[5]	**(20)**	(19)
Other comprehensive loss of equity investees, net of tax[6]	**(1)**	(2)
Total items that will be reclassified subsequently to net earnings	**(2)**	(3)
Other comprehensive income (loss)	**(7)**	5
Total comprehensive income	**66**	13
Total comprehensive income (loss) attributable to:		
Common shareholders	**45**	(4)
Non-controlling interests	**21**	17
	66	13

(1) Net of income tax recovery of 1 for the three months ended March 31, 2014 (2013 - 2 expense).

(2) Net of income tax of nil for the three months ended March 31, 2014 (2013 - nil).

(3) Net of income tax recovery of 7 for the three months ended March 31, 2014 (2013 - 3 recovery).

(4) Net of income tax expense of 2 for the three months ended March 31, 2014 (2013 - 2 recovery).

(5) Net of income tax expense of 1 for the three months ended March 31, 2014 (2013 - 3 expense).

(6) Net of income tax of nil for the three months ended March 31, 2014 (2013 - 1 recovery).

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**March 31, 2014**	Dec. 31, 2013 *(Restated)**
Cash and cash equivalents	**37**	42
Accounts receivable *(Note 8)*	**392**	473
Current portion of finance lease receivable	**3**	3
Collateral paid *(Note 8)*	**26**	20
Prepaid expenses	**39**	12
Risk management assets *(Notes 7 and 8)*	**116**	113
Inventory	**85**	77
Income taxes receivable	**13**	8
Assets held for sale *(Note 3)*	**211**	-
	922	748
Investments *(Note 3)*	-	192
Long-term portion of finance lease receivable	**389**	377
Property, plant, and equipment *(Note 9)*		
Cost	**12,143**	12,024
Accumulated depreciation	**(4,972)**	(4,831)
	7,171	7,193
Goodwill	**461**	460
Intangible assets	**323**	323
Deferred income tax assets	**108**	118
Risk management assets *(Notes 7 and 8)*	**102**	116
Other assets	**89**	97
Total assets	**9,565**	9,624
Accounts payable and accrued liabilities	**450**	447
Current portion of decommissioning and other provisions	**18**	16
Risk management liabilities *(Notes 7 and 8)*	**69**	85
Income taxes payable	**1**	3
Dividends payable *(Note 11)*	**53**	85
Current portion of finance lease obligation	**7**	8
Current portion of long-term debt *(Notes 7 and 10)*	**796**	209
	1,394	853
Long-term debt *(Notes 7 and 10)*	**3,493**	4,113
Long-term portion of finance lease obligation	**16**	17
Decommissioning and other provisions	**325**	316
Deferred income tax liabilities	**454**	459
Risk management liabilities *(Notes 7 and 8)*	**105**	103
Defined benefit obligation and other long-term liabilities	**342**	340
Equity		
Common shares *(Note 11)*	**2,941**	2,913
Preferred shares *(Note 12)*	**781**	781
Contributed surplus	**9**	9
Deficit	**(734)**	(735)
Accumulated other comprehensive loss	**(75)**	(62)
Equity attributable to shareholders	**2,922**	2,906
Non-controlling interests *(Note 6)*	**514**	517
Total equity	**3,436**	3,423
Total liabilities and equity	**9,565**	9,624

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

Commitments *(Note 13)*

Contingencies *(Note 14)*

Subsequent events *(Note 16)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

3 months ended March 31, 2014

Unaudited	**Common shares**	**Preferred shares**	**Contributed surplus**	**Deficit**	**Accumulated other comprehensive loss**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec. 31, 2013	2,913	781	9	(735)	(62)	2,906	517	3,423
Net earnings	-	-	-	58	-	58	15	73
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	6	6	-	6
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(13)	(13)	6	(7)
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(5)	(5)	-	(5)
Other comprehensive loss of equity investees, net of tax	-	-	-	-	(1)	(1)	-	(1)
Total comprehensive income (loss)				58	(13)	45	21	66
Common share dividends	-	-	-	(48)	-	(48)	-	(48)
Preferred share dividends	-	-	-	(9)	-	(9)	-	(9)
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(24)	(24)
Common shares issued	28	-	-	-	-	28	-	28
Balance, March 31, 2014	**2,941**	**781**	**9**	**(734)**	**(75)**	**2,922**	**514**	**3,436**

See accompanying notes.

3 months ended March 31, 2013

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive loss	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)	-	-	-	(2)	-	(2)	10	8
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	4	4	-	4
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(11)	(11)	7	(4)
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	7	7	-	7
Other comprehensive loss of equity investees, net of tax	-	-	-	-	(2)	(2)	-	(2)
Total comprehensive income (loss)				(2)	(2)	(4)	17	13
Common share dividends	-	-	-	(75)	-	(75)	-	(75)
Preferred share dividends	-	-	-	(9)	-	(9)	-	(9)
Distributions to non-controlling interests	-	-	-	-	-	-	(19)	(19)
Common shares issued	54	-	-	-	-	54	-	54
Balance, March 31, 2013	2,780	781	9	(448)	(138)	2,984	328	3,312

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2014**	2013
Operating activities		
Net earnings	**73**	8
Depreciation and amortization	**150**	139
Accretion of provisions	**5**	4
Decommissioning and restoration costs settled	**(3)**	(5)
Deferred income tax expense (recovery) *(Note 5)*	**10**	(25)
Unrealized (gain) loss from risk management activities	**(2)**	41
Unrealized foreign exchange gain	**9**	4
Provisions	**(2)**	(7)
Equity loss *(Note 3)*	**-**	4
Other non-cash items	**(3)**	16
Cash flow from operations before changes in working capital	**237**	179
Change in non-cash operating working capital balances	**42**	77
Cash flow from operating activities	**279**	256
Investing activities		
Additions to property, plant, and equipment *(Note 9)*	**(71)**	(125)
Additions to intangibles	**(6)**	(7)
Realized losses on financial instruments	**(16)**	(2)
Net decrease in collateral received from counterparties	**-**	(1)
Net (increase) decrease in collateral paid to counterparties	**(4)**	3
Decrease in finance lease receivable	**1**	1
Change in non-cash investing working capital balances	**(9)**	(19)
Cash flow used in investing activities	**(105)**	(150)
Financing activities		
Net decrease in borrowings under credit facilities *(Note 10)*	**(116)**	(33)
Repayment of long-term debt *(Note 10)*	**(2)**	(2)
Dividends paid on common shares *(Note 11)*	**(50)**	(20)
Dividends paid on preferred shares *(Note 12)*	**(9)**	(9)
Realized gains on financial instruments	**25**	-
Distributions paid to subsidiaries' non-controlling interests *(Note 6)*	**(26)**	(19)
Decrease in finance lease obligation	**(2)**	-
Other	**-**	(1)
Cash flow used in financing activities	**(180)**	(84)
Cash flow from (used) in operating, investing, and financing activities	**(6)**	22
Effect of translation on foreign currency cash	**1**	1
Increase (decrease) in cash and cash equivalents	**(5)**	23
Cash and cash equivalents, beginning of period	**42**	27
Cash and cash equivalents, end of period	**37**	50
Cash income taxes paid	**16**	12
Cash interest paid	**39**	39

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 which are available on SEDAR at www.sedar.com.

The unaudited interim condensed consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls.

The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis, except for certain financial assets and liabilities, which are stated at fair value.

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Board of Directors on April 28, 2014.

B. Use of Estimates

The preparation of these condensed consolidated financial statements in accordance with International Financial Reporting Standards ("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 2013 annual consolidated financial statements for a more detailed discussion of the critical accounting judgments and key sources of estimation uncertainty.

C. Significant Judgments

Management has assessed it is highly probable the transactions described in Note 3 will close within a one-year time frame, thereby meeting the conditions of IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations* for presenting the assets as held for sale within current assets. The net earnings for the three months ended March 31, 2014 includes the equity loss from these investments up to the date of this reclassification.

2. ACCOUNTING CHANGES

A. Current Accounting Policy Changes

I. Inception Gains and Losses

The Corporation restated the Condensed Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Condensed Consolidated Statement of Financial Position were immaterial. Refer to Note 7(C) for further information on inception gains and losses.

II. IAS 32 *Financial Instruments: Presentation*

On Jan. 1, 2014, the Corporation adopted the amendments to IAS 32 *Financial Instruments: Presentation*. There was no impact of adopting the IAS 32 amendments on the condensed consolidated financial statements.

III. IAS 36 *Impairment of Assets*

On Jan. 1, 2014, the Corporation adopted the amendments to the disclosure requirements of IAS 36 *Impairment of Assets*. The amended disclosure requirements did not have an impact on the condensed consolidated financial statements.

B. Future Accounting Changes

Accounting standards that have been previously issued by the International Accounting Standards Board ("IASB") but are not yet effective, and have not been applied by the Corporation include: IFRS 9 *Financial Instruments*. In February 2014, the IASB indicated that IFRS 9 will be effective for annual periods beginning on or after Jan. 1, 2018. The Corporation continues to assess the impact of adopting this standard.

C. Comparative Figures

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

3. ASSETS HELD FOR SALE

On Feb. 20, 2014, TransAlta announced it had entered into agreements to sell the Corporation's 50 per cent ownership of CE Generation, LLC ("CE Gen"), CalEnergy LLC, the Blackrock development project, and Wailuku Holding Company, LLC ("Wailuku") to MidAmerican Renewables for total proceeds of U.S.$193.5 million. While certain regulatory approvals are required, the Corporation anticipates that the sale of CE Gen, CalEnergy LLC, and the Blackrock development project will close in the second quarter of 2014 and that the sale of Wailuku will close in the fourth quarter of 2014. The assets held for sale are included in the Generation Segment. No loss was recognized on initial classification of the assets as held for sale as the assets continue to be measured at carrying amount. Coincident with the classification as held for sale, the Corporation no longer uses the equity method of accounting for CE Gen and Wailuku, and has also reclassified Blackrock project development costs from other assets.

4. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended March 31	
	2014	2013
Interest on debt	**61**	60
Capitalized interest	**-**	(2)
Interest expense	**61**	58
Accretion of provisions	**5**	4
Net interest expense	**66**	62

5. INCOME TAXES

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

	3 months ended March 31	
	2014	2013
Current income tax expense	**8**	8
Adjustments in respect of deferred income tax of a prior period	**1**	-
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**11**	(19)
Deferred income tax recovery resulting from changes in tax rates or laws (1)	**-**	(6)
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**(1)**	-
Deferred income tax recovery arising from the reversal of a previous writedown of deferred income tax assets	**(1)**	-
Income tax expense (recovery)	**18**	(17)

(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 March 31	
	2014	2013
Current income tax expense	**8**	8
Deferred income tax expense (recovery)	**10**	(25)
Income tax expense (recovery)	**18**	(17)

6. NON-CONTROLLING INTERESTS

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

I. TransAlta Cogeneration L.P.

	3 months ended March 31	
	2014	2013
Revenues	**82**	80
Net earnings	**20**	18
Total comprehensive income	**32**	32
Amounts attributable to the non-controlling interest:		
Net earnings	**10**	9
Total comprehensive income	**16**	16
Distributions to the non-controlling interest	**21**	18

As at	March 31, 2014	Dec. 31, 2013
Current assets	**56**	56
Long-term assets	**617**	632
Current liabilities	**(55)**	(56)
Long-term liabilities	**(65)**	(68)
Total equity	**(553)**	(564)
Equity attributable to the non-controlling interest	**(275)**	(280)
Non-controlling interest share (per cent)	**49.99**	49.99

II. TransAlta Renewables

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

3 months ended March 31	2014
Revenues	**68**
Net earnings and total comprehensive income	**22**
Amounts attributable to the non-controlling interests:	
Net earnings and total comprehensive income	**5**
Distributions to the non-controlling interests	**3**

As at	March 31, 2014	Dec. 31, 2013
Current assets	**51**	59
Long-term assets	**1,944**	1,954
Current liabilities	**(101)**	(100)
Long-term liabilities	**(813)**	(846)
Total equity	**(1,081)**	(1,067)
Equity attributable to non-controlling interests	**(239)**	(237)
Non-controlling interests share (per cent)(1)	**19.30**	19.30

(1) See Note 16 for details of subsequent change in the non-controlling interests.

7. FINANCIAL INSTRUMENTS

A. Financial Assets and Liabilities - Measurement

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

B. Fair Value of Financial Instruments

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

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

a. Level I

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

b. Level II

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

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

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.

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

c. Level III

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

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

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

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

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

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 March 31, 2014 is estimated to be a +/- $121 million (Dec. 31, 2013 - $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/-$94 million (Dec. 31, 2013 - $87 million) in the stress value stems from a long dated power sale contract that is designated as a cash flow hedge, while the remaining +/-$27 million (Dec. 31, 2013 - $18 million) accounts for the rest of the portfolio. 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 effects on fair values of significant unobservable inputs used in determining Level III fair values is as follows:

Description	Effects on fair values as at March 31, 2014	Valuation Technique	Unobservable input	Range
Unit contingent power purchases	26	Historical analysis	Price discount	0.4 - 1.5 per cent
			Volumetric discount[1]	0 - 11 per cent
Long-term power sales	211	Long-term price forecast	Illiquid future power prices (per MW)	U.S.$32 - U.S.$79 and $71 - $116
Coal supply revenue sharing	(9)	Vanilla and exotic option valuation techniques	Volumes (MWh)	18 - 25 per cent of available generation
			Illiquid commodity forward price volatilities	6 - 27 per cent
			Illiquid future power prices (per MWh)	U.S.$32 - U.S.$79
			Illiquid future coal prices (per Tonne)	U.S.$13 - U.S.$15
Unit contingent power sales	(3)	Black-Scholes	Illiquid commodity forward price volatilities	40 per cent
Transmission and financial transmission rights	1	Historical bootstrap	Illiquid forward power price spreads (per MWh)	$(8) - $9

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

Description	Effects on fair values as at Dec. 31, 2013	Valuation Technique	Unobservable input	Range
Unit contingent power purchases	43	Historical bootstrap	Price discount Volumetric discount[1]	0 - 2 per cent 0 - 14 per cent
Long-term power sale	225	Long-term price forecast	Illiquid future power prices (per MW)	$34.40 - $90.83
Coal supply revenue sharing	(12)	Black-Scholes	Volumes (MWh) Illiquid future implied volatilities in MidC power	18 - 25 per cent of available generation 35 per cent
Unit contingent power sales	(5)	Black-Scholes	Illiquid commodity forward price volatilities	55 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.

The effects on fair values of significant unobservable inputs exclude the effects of observable inputs such as liquidity and credit discounts, as well as unamortized inception gains and losses associated with these instruments.

II. 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 three months ended March 31, 2014 and 2013, 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, 2013	-	(66)	55	-	14	11	-	(52)	66
Changes attributable to:									
Market price changes on existing contracts	**-**	**(7)**	**(13)**	**-**	**(10)**	**8**	**-**	**(17)**	**(5)**
Market price changes on new contracts	**-**	**1**	**-**	**-**	**-**	**4**	**-**	**1**	**4**
Contracts settled	**-**	**8**	**(1)**	**-**	**30**	**(31)**	**-**	**38**	**(32)**
Net risk management assets (liabilities) March 31, 2014	**-**	**(64)**	**41**	**-**	**34**	**(8)**	**-**	**(30)**	**33**
Additional Level III information:									
Losses recognized in OCI			(13)			-			(13)
Total gains included in earnings before income taxes			1			12			13
Unrealized losses included in earnings before income taxes relating to net liabilities held at March 31, 2014			-			(19)			(19)

	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	-	(10)	(3)	-	(19)	10	-	(29)	7
Market price changes on new contracts	-	(2)	-	-	(10)	(17)	-	(12)	(17)
Contracts settled	-	2	-	1	(5)	(4)	1	(3)	(4)
Net risk management assets (liabilities) at March 31, 2013	-	(73)	-	-	45	17	-	(28)	17
Additional Level III information:									
Losses recognized in OCI			(3)			-			(3)
Total losses included in earnings before income taxes			-			(7)			(7)
Unrealized losses included in earnings before income taxes relating to net assets held at March 31, 2013			-			(11)			(11)

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy 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 three months ended March 31, 2014 and 2013, 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 at Dec. 31, 2013	-	26	-	-	1	-	-	27	-
Changes attributable to:									
Market price changes on existing contracts	**-**	**29**	**-**	**-**	**-**	**-**	**-**	**29**	**-**
Market price changes on new contracts	**-**	**(1)**	**-**	**-**	**(3)**	**-**	**-**	**(4)**	**-**
Contracts settled	**-**	**(11)**	**-**	**-**	**-**	**-**	**-**	**(11)**	**-**
Net risk management assets (liabilities) at March 31, 2014	**-**	**43**	**-**	**-**	**(2)**	**-**	**-**	**41**	**-**

	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	-	28	-	-	-	-	-	28	-
Market price changes on new contracts	-	(3)	-	-	1	-	-	(2)	-
Contracts settled	-	(1)	-	-	(1)	-	-	(2)	-
Net risk management assets (liabilities) at March 31, 2013	-	(26)	-	-	1	-	-	(25)	-

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value				Total carrying value
	Level I	Level II	Level III	Total	
Long-term debt[1] - March 31, 2014	**-**	**4,401**	**-**	**4,401**	**4,227**
Long-term debt[1] - Dec. 31, 2013	-	4,367	-	4,367	4,262

(1) Includes current portion and excludes $62 million (Dec. 31, 2013 - $60 million) of debt measured and carried at fair value.

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

The 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

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to Note 7(B) for Level III fair value valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss), and a reconciliation of changes during the period is as follows:

Three months ended March 31	**2014**	2013
Unamortized net gain at beginning of period	**160**	5
New inception gains	**5**	-
Amortization recorded in net earnings during the period	**4**	(2)
Unamortized net gain at end of period	**169**	3

8. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	March 31, 2014					Dec. 31, 2013 *(Restated)**
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	-	2	-	77	79	99
Long-term	-	71	-	17	88	101
Total energy trading risk management assets	-	73	-	94	167	200
Other						
Current	-	35	-	2	37	14
Long-term	-	7	7	-	14	15
Total other risk management assets	-	42	7	2	51	29
Risk management liabilities						
Energy trading						
Current	-	19	-	40	59	84
Long-term	-	77	-	28	105	102
Total energy trading risk management liabilities	-	96	-	68	164	186
Other						
Current	1	5	-	4	10	1
Long-term	-	-	-	-	-	1
Total other risk management liabilities	1	5	-	4	10	2
Net energy trading risk management assets (liabilities)	-	(23)	-	26	3	14
Net other risk management assets (liabilities)	(1)	37	7	(2)	41	27
Net total risk management assets (liabilities)	(1)	14	7	24	44	41

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

Hedges

a. Cash Flow Hedges

i. Energy Trading Risk Management

As at March 31, 2014, cumulative gains of $4 million related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in accumulated other comprehensive income (loss) (“AOCI”) and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Cash Flow Hedge Impacts

Over the next 12 months ended March 31, 2015, the Corporation estimates that $16 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 may 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 20(B) of the Corporation's most recent annual consolidated financial statements.

I. Commodity Price Risk

Value at Risk ("VaR") is the most commonly used metric employed to track and manage the market risk associated with commodity and other derivatives. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance - covariance approach.

a. Commodity Price Risk - Proprietary Trading

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

VaR at March 31, 2014 associated with the Corporation's proprietary energy trading activities was $2 million (Dec. 31, 2013 - $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 March 31, 2014 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $30 million (Dec. 31, 2013 - $42 million). VaR at March 31, 2014 associated with positions and economic hedges that do not meet hedge accounting requirements was $9 million (Dec. 31, 2013 - $11 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 March 31, 2014:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	85	15	**100**
Risk management assets	100	-	**100**

The Corporation's maximum exposure to credit risk at March 31, 2014, 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 5 of the 2013 annual consolidated financial statements), and including the fair value of open trading positions, net of any collateral held, at March 31, 2014 was $27 million (Dec. 31, 2013 - $23 million).

III. Liquidity Risk

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

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

	2014	2015	2016	2017	2018	2019 and thereafter	Total
Accounts payable and accrued liabilities	450	-	-	-	-	-	450
Debt[1]	206	710	29	751	754	1,837	4,287
Energy trading risk management (assets) liabilities	(11)	10	10	-	(6)	(6)	(3)
Other risk management (assets) liabilities	-	(30)	(3)	(1)	(7)	-	(41)
Interest on long-term debt[2]	160	182	175	165	125	801	1,608
Dividends payable	53	-	-	-	-	-	53
Total	**858**	**872**	**211**	**915**	**866**	**2,632**	**6,354**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2015 and 2017.
(2) Not recognized as a financial liability on the 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 March 31, 2014, the Corporation had posted collateral of $121 million (Dec. 31, 2013 - $94 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 $103 million of collateral to its counterparties based upon the value of the derivatives at March 31, 2014.

9. 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, 2013	77	2,952	912	2,242	578	153	279	7,193
Additions	**-**	**1**	**-**	**-**	**-**	**68**	**2**	**71**
Depreciation	**-**	**(69)**	**(25)**	**(24)**	**(14)**	**-**	**(3)**	**(135)**
Revisions and additions to decommissioning and restoration costs	**-**	**8**	**2**	**4**	**2**	**-**	**-**	**16**
Retirement of assets	**-**	**(4)**	**(1)**	**(1)**	**(1)**	**-**	**-**	**(7)**
Change in foreign exchange rates	**1**	**14**	**12**	**3**	**1**	**1**	**1**	**33**
Transfers	**1**	**51**	**5**	**6**	**3**	**(73)**	**7**	**-**
As at March 31, 2014	**79**	**2,953**	**905**	**2,230**	**569**	**149**	**286**	**7,171**

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

10. LONG-TERM DEBT

A. Debt and Letters of Credit

The amounts outstanding are as follows:

As at	**March 31, 2014**			Dec. 31, 2013		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**749**	**749**	**2.5%**	852	852	2.6%
Debentures	**1,242**	**1,251**	**6.1%**	1,269	1,251	6.1%
Senior notes[3]	**1,896**	**1,881**	**5.6%**	1,797	1,809	5.6%
Non-recourse[4]	**377**	**381**	**5.9%**	376	380	5.9%
Other	**25**	**25**	**6.2%**	28	28	6.3%
	4,289	**4,287**		4,322	4,320	
Less: recourse current portion	**(761)**	**(761)**		(209)	(209)	
Less: non-recourse current portion	**(35)**	**(35)**		-	-	
Total long-term debt	**3,493**	**3,491**		4,113	4,111	

(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 March 31, 2014 (Dec. 31, 2013 - U.S.$300 million).

(3) U.S. face value at March 31, 2014 - U.S.$1.7 billion (Dec. 31, 2013 - U.S.$1.7 billion).

(4) Includes U.S.$20 million at March 31, 2014 (Dec. 31, 2013 - U.S.$20 million).

As at March 31, 2014, TransAlta had a total of $2.1 billion (Dec. 31, 2013 - $2.1 billion) of committed credit facilities and bilateral credit facilities, of which $0.9 billion (Dec. 31, 2013 - $0.9 billion) was not drawn, and was available, subject to customary borrowing conditions.

The total outstanding letters of credit as at March 31, 2014 was $427 million (Dec. 31, 2013 - $370 million) with no (Dec. 31, 2013 - nil) amounts exercised by third parties under these arrangements. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business.

B. Restrictions

Debt agreements of $5 million related to the Windsor plant, owned by the Corporation's TransAlta Cogeneration L.P. 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 $342 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.

11. COMMON SHARES

A. Issued and Outstanding

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

	3 months ended March 31			
	2014		2013	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**268.2**	**2,916**	254.7	2,730
Issued under the dividend reinvestment and optional common share purchase plan	**2.1**	**28**	3.7	53
	270.3	**2,944**	258.4	2,783
Amounts receivable under Employee Share Purchase Plan	**-**	**(3)**	-	(4)
Issued and outstanding, end of period	**270.3**	**2,941**	258.4	2,779

B. Dividends

The following table summarizes the common share dividends declared or paid within the three months ended March 31:

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares
2014					
Feb. 20, 2014	Apr. 1, 2014	0.18	48	30	18
Oct. 30, 2013	Jan. 1, 2014	0.29	78	50	28
2013					
Jan. 28, 2013	Apr. 1, 2013	0.29	75	22	53
Oct. 24, 2012	Jan. 1, 2013	0.29	73	20	53

On April 1, 2014, 1.5 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.

12. 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.

At March 31, 2014 and Dec. 31, 2013, the Corporation had 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E Cumulative Redeemable Rate Reset First Preferred shares, issued and outstanding.

B. Dividends

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

		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
2014							
Feb. 20, 2014	March 31, 2014	0.2875	3	0.2875	3	0.3125	3
2013							
Jan. 28, 2013	March 31, 2013	0.2875	3	0.2875	3	0.3125	3

13. COMMITMENTS

At March 31, 2014, the Corporation has remaining commitments for $75 million related to construction of a new natural gas pipeline in Australia. This amount is expected to be spent within the next twelve months.

14. CONTINGENCIES

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

15. SEGMENT DISCLOSURES

A. Reported Segment Earnings (Loss)

3 months ended March 31, 2014	Generation	Energy Trading	Corporate	Total
Revenues	710	65	-	775
Fuel and purchased pow er	335	-	-	335
Gross margin	375	65	-	440
Operations, maintenance, and administration	112	19	13	144
Depreciation and amortization	129	-	6	135
Inventory w ritedow n	4	-	-	4
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	3	(3)	-	-
Operating income (loss)	120	49	(19)	150
Finance lease income	12	-	-	12
Net interest expense				(66)
Foreign exchange loss				(5)
Earnings before income taxes				91

3 months ended March 31, 2013	Generation	Energy Trading	Corporate	Total
Revenues	523	17	-	540
Fuel and purchased pow er	201	-	-	201
Gross margin	322	17	-	339
Operations, maintenance, and administration	92	7	16	115
Depreciation and amortization	122	-	5	127
Inventory w ritedow n	14	-	-	14
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	4	(4)	-	-
Operating income (loss)	83	14	(21)	76
Finance lease income	11	-	-	11
Equity loss	(4)	-	-	(4)
Net interest expense				(62)
Foreign exchange loss				(1)
Loss on assumption of pension obligations				(29)
Loss before income taxes				(9)

Included in the Generation Segment results for the three months ended March 31, 2014 is $7 million (March 31, 2013 - $7 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
March 31, 2014	**9,029**	**216**	**320**	**9,565**
Dec. 31, 2013 *(Restated)**	9,093	244	287	9,624

** See Note 2(A) 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 March 31	
	2014	2013
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**135**	127
Depreciation included in fuel and purchased power	**15**	11
Other	**-**	1
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**150**	139

16. SUBSEQUENT EVENTS

A. South Hedland Power Project

On April 15, 2014, the Corporation announced that it had been named the preferred bidder for the South Hedland Power Project in Western Australia. Subject to the finalization of necessary contracts and approvals, the project would see TransAlta build, own and operate a 150MW combined cycle gas power station in South Hedland, Western Australia. The investment is estimated at approximately AUD$550 million. The power station is expected to be delivering power in 2016, with full commissioning in 2017. The development will be fully contracted under 25 year agreements with Horizon Power, a state utility company and Fortescue Metals Group Ltd., a mining company. The project may be expanded to accommodate additional customers at later dates.

B. Secondary Offering of TransAlta Renewables Shares

In April, 2014, the Corporation completed the previously announced secondary offering of 10,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. In addition, the over-allotment option granted to the syndicate of underwriters, led by CIBC and RBC Capital Markets, was partially exercised for an additional 1,000,000 common shares, also at a price of $11.40 per common share.

The offering resulted in gross proceeds to the Corporation of $136.2 million. The Corporation will use the net proceeds from the offering to reduce indebtedness, to fund growth, and for general corporate purposes. Following completion of the offering, TransAlta owns approximately 70.3 per cent of the common shares of TransAlta Renewables.

SUPPLEMENTAL INFORMATION

		March 31, 2014	Dec. 31, 2013
Closing market price (TSX) ($)		**12.84**	13.48
Price range for the last 12 months (TSX) ($)	High	**15.55**	16.86
	Low	**12.60**	12.91
Debt to invested capital (%)		**55.3**	55.6
Debt to invested capital excluding non-recourse debt(1) (%)		**52.8**	53.3
Debt to invested capital including finance lease obligation and non-recourse debt (%)		**55.4**	55.7
Debt to comparable EBITDA(2) (times)		**4.0**	4.2
Return on equity attributable to common shareholders(2) (%)		**(0.5)**	(3.1)
Comparable return on equity attributable to common shareholders(1), (2) (%)		**4.2**	3.6
Return on capital employed(2) (%)		**4.1**	2.8
Comparable return on capital employed(1), (2) (%)		**5.5**	5.2
Cash dividends per share(2) ($)		**1.05**	1.16
Price to comparable earnings ratio(1), (2) (times)		**35.7**	43.5
Earnings coverage(2) (times)		**1.3**	0.9
Dividend payout ratio based on net earnings(2) (%)		**(2,536.4)**	(431.0)
Dividend payout ratio based on comparable earnings(1), (2) (%)		**290.6**	377.8
Dividend payout ratio based on funds from operations(1), (2), (3) (%)		**36.0**	42.0
Dividend yield(2) (%)		**8.2**	8.6
Adjusted cash flow to debt(2), (3) (%)		**18.4**	16.9
Adjusted cash flow to interest coverage(2), (3) (times)		**4.2**	4.0

(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 2013 ratios have been adjusted for the impact of the California claim.

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

Debt to comparable EBITDA = long-term debt including current portion - cash and cash equivalents / comparable EBITDA

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 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.

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 Power – Power derived from 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.

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

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.

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

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

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