TRANSALTA CORPORATION
THIRD QUARTER REPORT FOR 2009

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 page 29 for additional information.

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements of TransAlta Corporation as at and for the nine months ended Sept. 30, 2009 and 2008, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in our 2008 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 26, 2009. 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 two business segments: Generation and Commercial Operations & Development ("COD"). Our segments are supported by a corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to self-sustaining foreign operations is reflected in the equity section of the consolidated balance sheets.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Availability (%)	**83.9**	86.0	**84.4**	85.7
Production (GWh)	**11,610**	12,357	**33,439**	36,235
Revenue	**666**	791	**2,007**	2,302
Gross margin(1)	**380**	398	**1,107**	1,207
Operating income(1)	**120**	124	**219**	406
Net earnings	**66**	61	**102**	141
Net earnings per share, basic and diluted	**0.34**	0.31	**0.52**	0.71
Comparable earnings per share(1)	**0.34**	0.32	**0.49**	1.06
Cash flow from operating activities	**194**	202	**334**	610
Free cash flow (deficiency)(1)	**12**	20	**(196)**	(33)
Cash dividends declared per share	**0.29**	0.27	**0.87**	0.81

	As at Sept. 30, 2009	As at Dec. 31, 2008
Total assets	**7,870**	7,824
Total long-term financial liabilities	**3,889**	3,636

AVAILABILITY & PRODUCTION

Availability for the three months ended Sept. 30, 2009 decreased to 83.9 per cent from 86.0 per cent compared to the same period in 2008 due to higher unplanned outages at the Centralia Thermal plant (“Centralia Thermal”), and higher planned outages at the Alberta Thermal plants (“Alberta Thermal”), Windsor, and Mississauga.

Availability for the nine months ended Sept. 30, 2009 decreased to 84.4 per cent from 85.7 per cent compared to the same period in 2008 due to higher planned and unplanned outages at Alberta Thermal, and higher planned outages at Windsor and Mississauga, partially offset by lower planned and unplanned outages at Centralia Thermal, and no planned maintenance in 2009 at Genesee 3.

Production for the three months ended Sept. 30, 2009 decreased 747 gigawatt hours (“GWh”) compared to the same period in 2008 due to lower Power Purchase Agreement (“PPA”) customer demand, the expiration of the long-term contract at Saranac, higher unplanned outages at Centralia Thermal, and lower hydro volumes, partially offset by higher production at the Centralia gas-fired facility (“Centralia Gas”).

Production for the nine months ended Sept. 30, 2009 decreased 2,796 GWh compared to the same period in 2008 due to higher planned and unplanned outages at Alberta Thermal, higher economic dispatching at Centralia Thermal, lower PPA customer demand, lower hydro volumes, and the expiration of the long-term contract at Saranac, partially offset by lower planned and unplanned outages at Centralia Thermal, and no planned maintenance in 2009 at Genesee 3.

(1) Gross margin, Operating income, Comparable earnings, and Free cash flow are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 27 of this MD&A for further discussion of these items, including a reconciliation to net earnings and cash flow from operating activities.

NET EARNINGS

A reconciliation of net earnings is presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net earnings, 2008	61	141
Increase (decrease) in Generation gross margins	4	(69)
Mark-to-market movements - Generation	(8)	13
Decrease in COD gross margins	(14)	(44)
Decrease (increase) in operations, maintenance, and administration cost	17	(51)
Increase in depreciation expense	(3)	(34)
Increase in net interest expense	(3)	(1)
Decrease in equity loss	-	97
Decrease in non-controlling interest	12	11
(Increase) decrease in income tax expense	(5)	29
Other	5	10
Net earnings, 2009	**66**	**102**

Generation gross margins, net of mark-to-market movements, were comparable for the three months ended Sept. 30, 2009 to the same period in 2008 as a result of favourable contractual pricing, lower penalties due to lower spot pricing, and favourable foreign exchange rates, largely offset by lower hydro volumes, the expiration of the long-term contract at Saranac, and lower production at Centralia Thermal.

For the nine months ended Sept. 30, 2009, Generation gross margins, net of mark-to-market movements, decreased due to higher planned and unplanned outages at Alberta Thermal, lower hydro volumes, and the expiration of the long-term contract at Saranac, partially offset by favourable foreign exchange rates, favourable contractual pricing, and no planned maintenance in 2009 at Genesee 3.

For the three months and nine months ended Sept. 30, 2009, COD gross margins decreased relative to the same period in 2008 due to the effect of reduced industrial demand, gas price uncertainty, and market structure changes in the Western region.

Operations, maintenance, and administration ("OM&A") costs for the three months ended Sept. 30, 2009 decreased primarily due to targeted cost savings throughout the company and lower compensation costs.

For the nine months ended Sept. 30, 2009, OM&A costs increased compared to the same period in 2008 primarily due to higher planned outages and unfavourable foreign exchange rates, partially offset by targeted cost savings throughout the company and lower compensation costs.

Depreciation expense for the three months ended Sept. 30, 2009 is comparable with the prior period as a result of an increased asset base and unfavourable foreign exchange being partially offset by lower production at Saranac, which is depreciated on a unit of production basis.

For the nine months ended Sept. 30, 2009, depreciation expense increased compared to the same period in 2008 due to unfavourable foreign exchange rates, an increased asset base, and the retirement of certain assets during planned maintenance activities, partially offset by reduced production at Saranac and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal in 2008.

In the first quarter of 2008, an equity loss of $97 million was recorded to reflect the writedown of our Mexican investment that was sold in the fourth quarter of the same year.

For the three and nine months ended Sept. 30, 2009, non-controlling interest decreased primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac.

Income tax expense increased for the three months ended Sept. 30, 2009 compared to the same period in 2008 due to higher pre-tax earnings.

For the nine months ended Sept. 30, 2009, income tax expense decreased compared to the same period in 2008 due to lower pre-tax earnings, partially offset by the tax recovery on the writedown of our Mexican investment in 2008.

CASH FLOW

Cash flow from operating activities for the three months ended Sept. 30, 2009 decreased $8 million due to unfavourable changes in working capital, partially offset by higher cash earnings.

Cash flow from operating activities for the nine months ended Sept. 30, 2009 decreased $276 million due to lower cash earnings, the receipt of an additional PPA payment in 2008, and higher inventory balances in 2009.

Free cash flow for the three months ended Sept. 30, 2009 decreased $8 million primarily due to lower cash earnings.

The free cash flow deficiency for the nine months ended Sept. 30, 2009 increased $163 million compared to the same period in 2008 due to lower cash earnings and the receipt of an additional PPA payment in 2008.

SIGNIFICANT EVENTS

Three months ended Sept. 30, 2009

Sarnia Contract

On Sept. 30, 2009, we entered into a new agreement with the Ontario Power Authority (“OPA”) for our Sarnia regional cogeneration power plant. The contract is capacity based and the term of the new agreement is from July 1, 2009 through to the end of 2025. While the specific terms and conditions of the new agreement are confidential, the OPA has indicated that the agreement is in line with other similar agreements issued by the OPA.

Offer to Acquire Canadian Hydro Developers, Inc.

On July 20, 2009 we announced an all-cash offer to acquire Canadian Hydro Developers, Inc. ("Canadian Hydro") at an initial price of $4.55 per share. On Oct. 5, 2009, we increased our all-cash offer to $5.25 per share. As of October 23, 2009 we have completed the acquisition and payment for approximately 87 percent of the outstanding common shares of Canadian Hydro. Refer to the Subsequent Events section of this MD&A for further details.

Nine months ended Sept. 30, 2009

Carbon Capture and Storage

On June 30, 2009 the Alberta Government announced that our Project Pioneer was not selected as part of the first carbon capture and storage (“CCS”) projects to receive funding under its $2 billion CCS initiative. Refer to the Subsequent Events section of this MD&A for further details.

Senior Notes Offering

On May 26, 2009, we announced an offering of $200 million senior notes maturing in 2014 and bearing an interest rate of 6.45 per cent. The net proceeds from the offering will be used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

Major Maintenance Plans

On May 20, 2009, we announced the advancement of a major maintenance outage on Unit 3 of our Sundance facility from the second quarter of 2010 into the second and third quarters of 2009. The advancement of the maintenance outage takes advantage of current low power prices, optimizes preventative maintenance in the short-term, and is expected to provide an economic cash benefit over the two-year period, and improves the unit’s availability. As a result of the change in schedule, 2009 lost GWh increased by 396 GWh and net income declined by $24 million ($0.12 per share).

Normal Course Issuer Bid (“NCIB”) Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval to purchase, for cancellation, up to 9.9 million of our common shares representing 5 per cent of our 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. No purchases were made under the NCIB program through Sept. 30, 2009.

Chief Operating Officer

On April 28, 2009 we announced the appointment of Dawn Farrell to the position of Chief Operating Officer. In this new role, Ms. Farrell will lead our operations, commercial, engineering, technology, and procurement activities. Prior to this appointment, Ms. Farrell was Executive Vice President of Commercial Operations and Development.

Additionally, Richard Langhammer, Executive Vice President of Generation Operations, took on a new assignment as Chief Productivity Officer for the remainder of 2009 with the responsibility for identifying strategies to create sustainable costs savings across the company. Mr. Langhammer announced his retirement earlier this year; he will formally retire at the end of 2009 after 23 years of service.

Ardenville Wind Power Project

On April 28, 2009, we announced plans to design, build, and operate Ardenville, a 69 megawatt (“MW”) wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the capital cost of the project is the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the remainder of the Ardenville wind project is expected to commence in the first quarter of 2011.

Sundance Unit 4 Derate

On Feb. 10, 2009, we reported the first quarter financial impact of an extended derate on Unit 4 of our Sundance facility ("Unit 4"). The facility experienced an unplanned outage in December 2008 related to the failure of an induced draft fan. At that time, Unit 4, which has a capacity of 406 MW, had been derated to approximately 205 MW. The repair of the induced draft fan components by the original equipment manufacturer took longer than planned, and therefore, Unit 4 did not return to full service until Feb. 23, 2009. As a result of the extended derate, first quarter production and net earnings were reduced by 328 GWh and $10 million, respectively representing both lost merchant revenue and penalties.

In response to this event, as required by the appropriate PPA legislation, we gave notice of a High Impact Low Probability Force Majeure Event to the PPA Buyer and the Balancing Pool. On April 27, 2009, the Balancing Pool rejected our assertion that this outage should be regarded as a High Impact Low Probability Force Majeure Event. As required by the PPA legislation, we were required to pay the penalties related to the derate. As a result, accounting standards required that we also record an additional charge in the second quarter of $7 million after-tax related to this event. We settled the issue in the third quarter and the terms of the settlement are confidential.

Keephills Units 1 and 2 Uprates

On Jan. 29, 2009, we announced a 46 MW (23 MW per unit) efficiency uprate at Unit 1 and Unit 2 of our Keephills facility. The total capital cost of the project is estimated at $68 million with commercial operations of Unit 2 expected by the end of 2011 and Unit 1 by the end of 2012.

Dividend Increase

On Jan. 28, 2009, our Board of Directors declared a quarterly dividend of $0.29 per share on common shares, an increase of $0.02 per share, which on an annual basis will yield $1.16 per share versus $1.08 per share in 2008.

SUBSEQUENT EVENTS

Keephills 3

On Oct. 26, 2009, the Board of Directors approved an increase in the construction cost of Keephills 3 to $988 million due to a change in our original expectations of the labour required to complete the project, and a change to the commencement of commercial operations from the first quarter of 2011 to the second quarter of 2011. The increase in construction cost is due to a change in our original expectations of the labour required to complete the project. Even with the delay of operations and increased cost, Keephills 3 is still expected to meet our investment hurdles.

Carbon Capture and Storage

On Oct. 14, 2009, the federal and provincial governments announced that our CCS project, Project Pioneer, has received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a Front End Engineering and Design ("FEED") study to determine if the project is viable. The FEED study is expected to cost $20 million; $10 million will come from the federal government, $5 million will come from the provincial government, and $5 million will come from TransAlta and from industry partners Alstom Canada and Capital Power Corporation. The FEED study is expected to be complete in 2010 and if we proceed with construction, the prototype plant has a targeted start-up date of 2015.

Offer to Acquire Canadian Hydro

On Oct. 5, 2009, we entered into a definitive pre-acquisition agreement with Canadian Hydro to acquire all of their issued and outstanding common shares for $5.25 per share in cash. The transaction has a total value of approximately $1.7 billion, and has the unanimous support of the Board of Directors of both companies. The amended offer is subject to certain conditions, including acceptance of the amended offer by holders of at least 66⅔ per cent of Canadian Hydro's common shares calculated on a fully-diluted basis.

On Oct. 23, 2009, we completed the acquisition and payment for approximately 87 percent of the outstanding common shares of Canadian Hydro. We have extended our amended offer for common shares of Canadian Hydro to 3:00 p.m. (Calgary time) on Nov. 3, 2009 to allow additional time for Canadian Hydro shareholders to tender their shares.

Canadian Hydro operates 694 MW of wind, hydro, and biomass facilities in Alberta, Ontario, Quebec, and British Columbia. Canadian Hydro's assets are highly contracted with counterparties of recognized financial standing. On a combined basis, we will have 9,144 MW of gross generating capacity [(1)] in operation (8,657 MW net ownership interest). The renewables portfolio will include 1,900 MW in operation, or 22 per cent of the combined portfolio. In addition, there would be 543 MW net under construction and over 500 MW in advanced-stage development.

The transaction will be initially funded with new committed credit facilities that are fully underwritten by a Canadian chartered bank, which, along with existing credit facilities and internally generated cash will provide ample funding to take up and pay for all of the outstanding Canadian Hydro shares. The transaction is not expected to impact our dividend policy.

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 Pacific Northwest, 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 2008 Annual Report. The key characteristics of these markets are described below.

Electricity Prices

Please refer to page 21 of the 2008 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the third quarter of 2009 and 2008 in our three main markets are shown in the following graphs.

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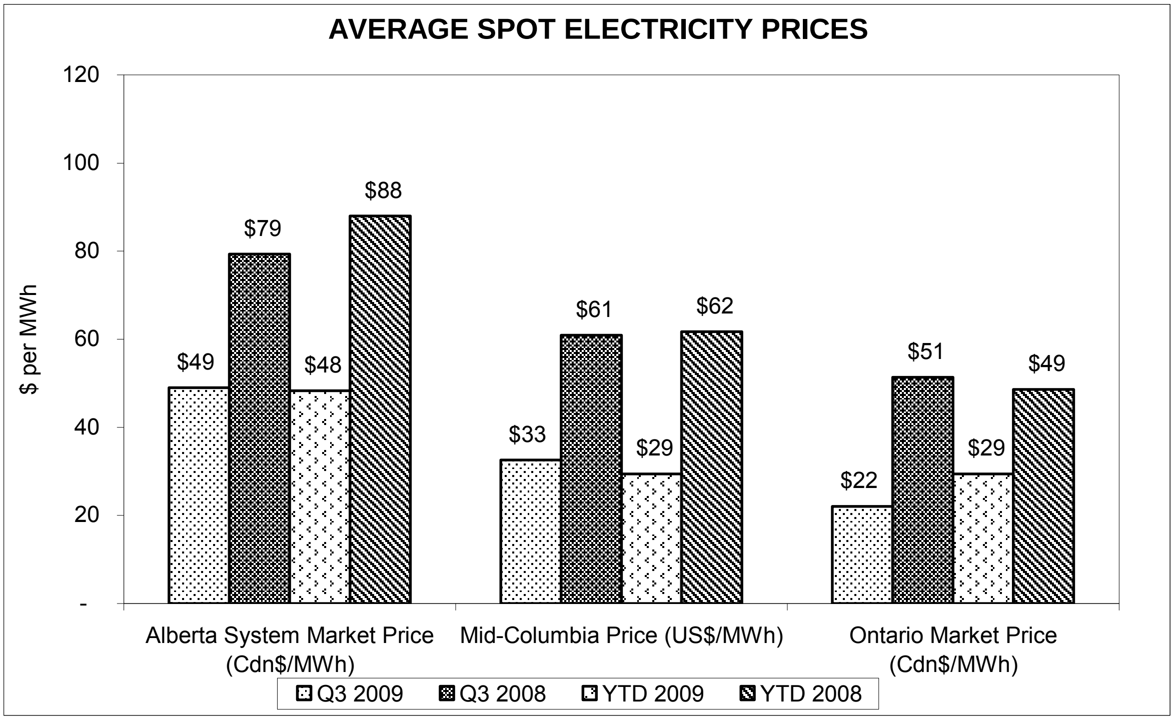
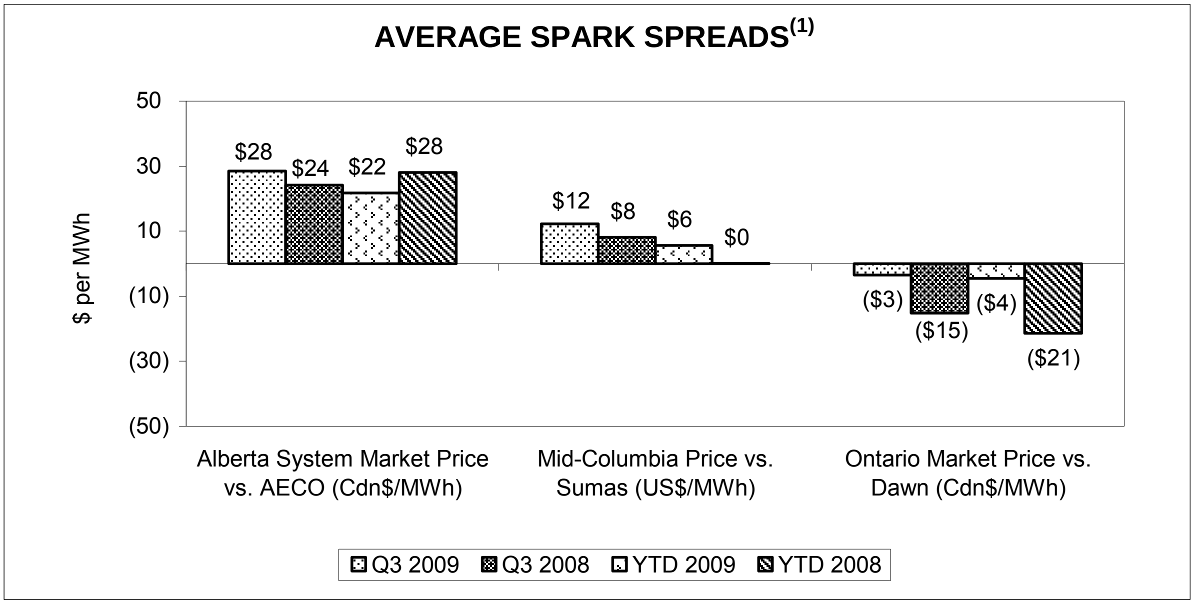
(1) We measure capacity as net maximum capacity (see glossary for definition of this and other key items) which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.



For the third quarter of 2009, average spot prices decreased in Alberta, the Pacific Northwest, and in Ontario compared to the same period in 2008 due to lower natural gas prices and weaker demand for electricity.

For the nine months ended Sept. 30, 2009, average electricity prices in all three markets were lower than the same period in 2008. These lower prices were primarily due to lower natural gas prices and lower demand for electricity. Details on how our contracted assets and hedging activities help reduce the impact of price changes upon our current results are discussed below. Discussion of our longer-term plans for helping to reduce the impact of price changes to our results are discussed in further detail on page 21 of this MD&A.



(1) For a 7,000 Btu/KWh heat rate plant.

For the three months ended Sept. 30, 2009, average spark spreads increased in Alberta, the Pacific Northwest and Ontario compared to the same period in 2008 due to power prices decreasing less than natural gas prices.

For the nine months ended Sept. 30, 2009, average spark spreads decreased in Alberta relative to the same period in 2008 due to power prices decreasing more than natural gas prices. Spark spreads in the Pacific Northwest and Ontario increased relative to 2008 as power prices have decreased less than natural gas prices.

During the third quarter, our consolidated power portfolio was over 95 per cent hedged at an average price ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and an average price ranging from U.S.$50-$55/MWh in the Pacific Northwest. The use of these hedges reduced the impact of lower prices upon our consolidated financial results.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: *Comprised of hydro, wind, geothermal, natural gas- and coal-fired plants, and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support (see the detailed discussion of the four revenue streams in our 2008 Annual Report). At Sept. 30, 2009, Generation had 8,386 MW of gross generating capacity[(1)] in operation (7,963 MW net ownership interest) and 525 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 18 of our 2008 Annual Report.*

The results of the Generation segment are as follows:

3 months ended Sept. 30	**2009 Total**	**2009 Per installed MWh[(1)]**	2008 Total	2008 Per installed MWh[(1)]
Revenues	**659**	**35.59**	770	41.60
Fuel and purchased power	**(286)**	**(15.45)**	(393)	(21.23)
Gross margin	**373**	**20.14**	377	20.37
Operations, maintenance and administration	**116**	**6.27**	129	6.97
Depreciation and amortization	**106**	**5.72**	102	5.51
Taxes, other than income taxes	**5**	**0.27**	5	0.27
Intersegment cost allocation	**8**	**0.43**	7	0.38
Operating expenses	**235**	**12.69**	243	13.13
Operating income	**138**	**7.45**	134	7.24
Installed capacity (GWh)	**18,516**		18,511	
Production (GWh)	**11,610**		12,357	
Availability (%)	**83.9**		86.0	

9 months ended Sept. 30	**2009 Total**	**2009 Per installed MWh[(1)]**	2008 Total	2008 Per installed MWh[(1)]
Revenues	**1,970**	**35.86**	2,221	40.21
Fuel and purchased power	**(900)**	**(16.38)**	(1,095)	(19.82)
Gross margin	**1,070**	**19.48**	1,126	20.38
Operations, maintenance and administration	**434**	**7.90**	368	6.66
Depreciation and amortization	**330**	**6.01**	298	5.39
Taxes, other than income taxes	**17**	**0.31**	15	0.27
Intersegment cost allocation	**24**	**0.44**	22	0.40
Operating expenses	**805**	**14.66**	703	12.73
Operating income	**265**	**4.82**	423	7.66
Installed capacity (GWh)	**54,938**		55,240	
Production (GWh)	**33,439**		36,235	
Availability (%)	**84.4**		85.7	

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

Production and Gross Margins

Generation's production volumes, electricity and steam production revenues, and fuel and purchased power costs based on geographical regions are presented below.

3 months ended Sept. 30, 2009	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & purchased power**	**Gross margin**	**Revenue per installed MWh(1)**	**Fuel & purchased power per installed MWh(1)**	**Gross margin per installed MWh(1)**
Western Canada	**7,311**	**11,538**	**295**	**106**	**189**	**25.57**	**9.19**	**16.38**
Eastern Canada	**818**	**1,868**	**83**	**44**	**39**	**44.43**	**23.55**	**20.88**
International	**3,481**	**5,110**	**281**	**136**	**145**	**54.99**	**26.61**	**28.38**
	11,610	**18,516**	**659**	**286**	**373**	**35.59**	**15.45**	**20.14**

3 months ended Sept. 30, 2008	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh(1)	Fuel & purchased power per installed MWh(1)	Gross margin per installed MWh(1)
Western Canada	7,839	11,531	316	132	184	27.40	11.45	15.96
Eastern Canada	801	1,808	117	84	33	64.71	46.46	18.25
International	3,717	5,172	337	177	160	65.16	34.22	30.94
	12,357	18,511	770	393	377	41.60	21.23	20.37

9 months ended Sept. 30, 2009	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & purchased power**	**Gross margin**	**Revenue per installed MWh(1)**	**Fuel & purchased power per installed MWh(1)**	**Gross margin per installed MWh(1)**
Western Canada	**22,227**	**34,230**	**841**	**316**	**525**	**24.57**	**9.23**	**15.34**
Eastern Canada	**2,701**	**5,543**	**294**	**171**	**123**	**53.04**	**30.85**	**22.19**
International	**8,511**	**15,165**	**835**	**413**	**422**	**55.06**	**27.23**	**27.83**
	33,439	**54,938**	**1,970**	**900**	**1,070**	**35.86**	**16.38**	**19.48**

9 months ended Sept. 30, 2008	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh(1)	Fuel & purchased power per installed MWh(1)	Gross margin per installed MWh(1)
Western Canada	24,522	34,347	1,012	391	621	29.46	11.38	18.08
Eastern Canada	2,416	5,386	381	274	107	70.74	50.87	19.87
International	9,297	15,507	828	430	398	53.40	27.73	25.67
	36,235	55,240	2,221	1,095	1,126	40.21	19.82	20.38

Western Canada

Our Western Canada assets consist of coal and natural gas-fired plants, hydro facilities, and wind farms. Refer to page 36 of our 2008 Annual Report for further details on our Western operations.

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

The change in production for the three and nine months ended Sept. 30, 2009 is reconciled below:

	3 months ended Sept. 30	9 months ended Sept. 30
	(GWh)	(GWh)
Production, 2008	7,839	24,522
Lower hydro volumes	(156)	(348)
Higher planned outages at Alberta Thermal	(78)	(1,278)
Lower (higher) unplanned outages at Alberta Thermal	35	(259)
No planned outage at Genesee 3 in 2009	-	145
Lower PPA customer demand	(292)	(536)
Other	(37)	(19)
Production, 2009	**7,311**	**22,227**

The change in gross margin for the three and nine months ended Sept. 30, 2009 is reconciled below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2008	184	621
Higher planned outages at Alberta Thermal	(5)	(99)
Lower hydro volumes and prices	(14)	(32)
Lower (higher) unplanned outages at Alberta Thermal	2	(11)
No planned outage at Genesee 3 in 2009	-	12
Adjustment to prior period indices	14	14
Mark-to-market movements	(2)	3
Higher coal costs	-	(8)
Lower penalties due to lower spot prices	11	11
Other	(1)	14
Gross margin, 2009	**189**	**525**

Indices, based upon changes in regional costs, are used in determining several components of revenue earned under the Alberta PPAs. In 2009, the indices used in these calculations during 2002 through to 2008 were revised, resulting in an increase in the revenue earned under the PPAs.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities and one wind farm. Refer to page 37 of our 2008 Annual Report for further details on our Eastern operations.

Production for the three months ended Sept. 30, 2009 increased 17 GWh primarily due to the commissioning of Kent Hills and higher market heat rates at Sarnia, partially offset by higher planned outages at the Mississauga and Windsor facilities.

Production for the nine months ended Sept. 30, 2009 increased 285 GWh primarily due to the commissioning of Kent Hills and higher market heat rates at Sarnia.

For the three months ended Sept. 30, 2009, gross margin increased $6 million due to the commissioning of Kent Hills and the new agreement with the OPA at our Sarnia regional cogeneration power plant, partially offset by higher planned outages at the Mississauga and Windsor facilities.

Gross margin for the nine months ended Sept. 30, 2009 increased $16 million due to the commissioning of Kent Hills and the new agreements with the OPA at our Sarnia regional cogeneration power plant.

International

Our International assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States and natural gas assets in Australia. Refer to page 37 of our 2008 Annual Report for further details on our International operations.

The change in production for the three and nine months ended Sept. 30, 2009 is reconciled below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2008	3,717	9,297
Lower planned outages at Centralia Thermal	-	613
(Higher) lower unplanned outages at Centralia Thermal	(165)	107
Economic dispatching at Centralia Thermal	(24)	(1,331)
Expiration of Saranac contract	(199)	(199)
Higher production at Centralia Gas	130	2
Other	22	22
Production, 2009	**3,481**	**8,511**

The change in gross margin for the three and nine months ended Sept. 30, 2009 is reconciled below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2008	160	398
Lower production at Centralia Thermal	(6)	(5)
Favourable pricing	8	30
Favourable foreign exchange	7	49
Higher coal costs	(4)	(17)
Mark-to-market movements	(3)	11
Favourable commercial settlements in 2008	-	(14)
Expiration of Saranac contract	(17)	(17)
Other	-	(13)
Gross margin, 2009	**145**	**422**

The mark-to-market movements primarily relate to contracts that did not qualify for hedge accounting in 2008 due to the expected reduced production at Centralia Thermal during the boiler modification work planned for 2009.

The PPA between our Saranac facility and New York State Electric and Gas expired in June 2009. The facility now operates under a combined capacity and merchant dispatch contract. As the facility is depreciated on a unit of production basis, there is a corresponding $5 million decrease in depreciation expense from this lower level of production. Further, as a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. Therefore, the net pre-tax earnings impact of this event is approximately $4 million.

Operations, Maintenance and Administration Expense

OM&A costs for the three months ended Sept. 30, 2009 decreased primarily due to targeted cost savings.

For the nine months ended Sept. 30, 2009, OM&A costs increased compared to the same period in 2008 primarily due to higher planned outages and unfavourable foreign exchange rates, partially offset by targeted cost savings.

Depreciation Expense

The change in depreciation expense for the three and nine months ended Sept. 30, 2009 is reconciled below:

	3 months ended Sept. 30	9 months ended Sept. 30
Depreciation and amortization expense, 2008	102	298
Increased asset base	5	9
Unfavourable foreign exchange	2	15
Asset retirements	3	9
Expiration of Saranac PPA	(5)	(5)
Acceleration depreciation at Centralia Thermal in 2008	(1)	(11)
Other	-	15
Depreciation and amortization expense, 2009	**106**	**330**

COMMERCIAL OPERATIONS & DEVELOPMENT ("COD"): *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving gross margins while remaining within Value at Risk ("VaR") limits is a key measure of COD's trading activities.*

COD is responsible for the management of commercial activities for our current generating assets. COD also manages available generating capacity as well as the fuel and transmission needs of the Generation business by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas, coal, and transmission capacity. Further, COD is responsible for developing or acquiring new cogeneration, wind, geothermal, and hydro generating assets and recommending portfolio optimization opportunities. The results of all of these activities are included in the Generation segment.

For a more in-depth discussion of our Energy Trading activities, refer to page 38 of our 2008 Annual Report.

The results of the COD segment are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Gross margin	**7**	21	**37**	81
Operations, maintenance and administration	**9**	17	**25**	37
Depreciation and amortization	**1**	1	**2**	2
Intersegment cost allocation	**(8)**	(7)	**(24)**	(22)
Operating expenses	**2**	11	**3**	17
Operating income	**5**	10	**34**	64

For the three months and nine months ended Sept. 30, 2009, COD gross margins decreased relative to the same period in 2008 due to the effect of reduced industrial demand, gas price uncertainty, and market structure changes in the Western region.

OM&A costs for the three months and nine months ended Sept. 30, 2009 decreased compared to the same period in 2008 due to a reduction in both discretionary expenditures and staff compensation costs.

The inter-segment cost allocations are comparable with prior periods.

NET INTEREST EXPENSE

The components of interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Interest on long-term debt	**46**	45	**132**	129
Interest income	**(3)**	(6)	**(6)**	(15)
Capitalized interest	**(10)**	(6)	**(27)**	(13)
Other	**3**	-	**3**	-
Net interest expense	**36**	33	**102**	101

The change in net interest expense for the three months and nine months ended Sept. 30, 2009, compared to the same period in 2008 is shown below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net interest expense, 2008	33	101
Higher long-term debt levels	4	8
Lower interest rates	(4)	(12)
Lower interest income	3	9
Higher capitalized interest	(4)	(14)
Unfavourable foreign exchange and other	4	10
Net interest expense, 2009	**36**	**102**

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2009 decreased $12 million and $11 million, respectively, due to lower earnings at CE Generation, LLC (“CE Gen”) as a result of the expiration of the Saranac contract and lower earnings at TransAlta Cogeneration, L.P. (“TA Cogen”).

INCOME TAXES

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Earnings before income taxes	**82**	72	**102**	170
Equity loss	**-**	-	**-**	97
Other income	**-**	-	**(7)**	(5)
Earnings before income taxes, equity loss, and other income	**82**	72	**95**	262
Income tax expense	**16**	11	**-**	29
Income tax expense on other income	**-**	-	**(1)**	(1)
Income tax expense on writedown of equity investment	**-**	-	**-**	28
Income tax expense excluding equity loss and other income	**16**	11	**(1)**	56
Effective tax rate on earnings before income taxes, equity loss, and other income (%)	**20**	15	**(1)**	21

Income tax expense increased for the three months ended Sept. 30, 2009 compared to the same period in 2008 due to higher pre-tax earnings. For the nine months ended Sept. 30, 2009 income tax expense decreased compared to the same period in 2008 due to lower pre-tax earnings, partially offset by the tax recovery on the writedown of our Mexican investment in 2008.

The effective tax rate increased for the three months ended Sept. 30, 2009 and decreased for the nine months ended Sept. 30, 2009 compared to the same periods in 2008 primarily due to a change in pre-tax earnings and certain deductions that do not fluctuate with earnings.

FINANCIAL POSITION

The following chart highlights significant changes in the Consolidated Balance Sheets from Dec. 31, 2008 to Sept. 30, 2009:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	36	Timing of operational payments primarily at CE Gen
Accounts receivable	(140)	Timing of customer receipts and lower revenues
Collateral paid	(11)	Collateral paid to counterparties associated with our obligations as a result of a change in forward prices
Inventory	40	Lower production and economic dispatching
Risk management assets (current and long-term)	(45)	Price movements
Property, plant, and equipment, net	217	Capital additions, partially offset by depreciation expense
Intangible assets	(52)	Amortization expense and strengthening of the Canadian dollar compared to the U.S. dollar
Other assets	28	Growth and productivity initiatives
Accounts payable and accrued liabilities	(209)	Timing of payments and lower operational and construction expenditures
Collateral received	83	Collateral collected from counterparties associated with their obligations as a result of a change in forward prices
Long-term debt (including current portion)	292	Issuance of long-term debt and increased draws on credit facilities, partially offset by foreign exchange and maturities
Risk management liabilities (current and long-term)	(150)	Price movements
Asset retirement obligation (including current portion)	(18)	Strengthening of the Canadian dollar compared to the U.S. dollar and costs settled
Deferred credits and other long-term liabilities	10	Timing of accrued benefits and deferred revenues
Net future income tax liabilities (including current portions)	50	Tax effect on the increase in net risk management assets
Non-controlling interests	15	Sale of portion of Kent Hills, partially offset by distributions in excess of earnings attributable to non-controlling interests

FINANCIAL INSTRUMENTS

Refer to *Note 7* on page 84 of the 2008 Annual Report and the interim consolidated financial statements as at and for the nine months ended Sept. 30, 2009 for details on Financial Instruments. During the quarter, the net risk management asset position decreased as a result of decreases in future prices on contracts in our Generation segment. Refer to the 'Risk Management' section in the MD&A of our 2008 Annual Report outlining our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2008.

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under GAAP 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 or upon internally developed assumptions or inputs. Our Level III fair values are determined using valuation techniques with inputs that are based on historical 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. At Sept. 30, 2009, Level III financial instruments had a net carrying value of $4 million (Dec. 31, 2008 – nil).

STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the three months ended Sept. 30, 2009 and 2008:

3 months ended Sept. 30	**2009**	2008	Primary factors explaining change
Cash and cash equivalents, beginning of period	**54**	50	
Provided by (used in):			
Operating activities	**194**	202	Unfavourable changes in working capital of $11 million, partially offset by higher cash earnings of $3 million.
Investing activities	**(270)**	(292)	Decrease in capital spending of $37 million, partially offset by a decrease in collateral held of $15 million.
Financing activities	**110**	109	Decreased debt maturities of $108 million and decreased distributions to non-controlling interests of $18 million, partially offset by lower draws on credit facilities of $126 million.
Translation of foreign currency cash	**(2)**	(3)	
Cash and cash equivalents, end of period	**86**	66	

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the nine months ended Sept. 30, 2009 and 2008:

9 months ended Sept. 30	**2009**	2008	Primary factors explaining change
Cash and cash equivalents, beginning of period	**50**	51	
Provided by (used in):			
Operating activities	**334**	610	Decrease in cash earnings of $116 million and unfavourable changes in working capital of $160 million.
Investing activities	**(562)**	(626)	Collateral received from counterparties of $105 million, partially offset by a decrease in realized gains on financial instruments of $53 million.
Financing activities	**266**	31	Increased draws on credit facilities of $193 million, decreased long-term debt maturities of $220 million, and decreased share repurchases of $130 million, partially offset by lower debt issuances of $302 million.
Translation of foreign currency cash	**(2)**	-	
Cash and cash equivalents, end of period	**86**	66	

LIQUIDITY AND CAPITAL RESOURCES

Details on our liquidity needs and capital resources can be found on page 46 of our 2008 Annual Report.

Our ability to generate adequate cash flow from operations, maintain our financial capacity and flexibility, and to provide for planned growth remains substantially unchanged since Dec. 31, 2008.

Debt

Recourse and non-recourse debt totalled $3.1 billion at Sept. 30, 2009 compared to $2.8 billion at Dec. 31, 2008. Amounts drawn on credit facilities increased in 2009 as a result of lower cash earnings and higher capital expenditures, partially offset by an increase in collateral received in 2009, which was used to repay credit facility balances. Total long-term debt increased from Dec. 31, 2008 primarily due to debt issued during the second quarter of 2009.

Credit Facilities

We have a total of $2.1 billion of committed credit facilities of which $1.1 billion is not drawn and is available as of Sept. 30, 2009, subject to customary borrowing conditions. At Sept. 30, 2009, credit utilized under these facilities is $1.0 billion, which is comprised of actual drawings of $744 million and of letters of credit of $296 million.

Beyond the cash flow generated by our business, our primary source for short-term liquidity requirements is from our $2.1 billion of committed credit facilities. These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2012, with the remainder comprised of bilateral credit facilities which mature between 2010 and 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Share Capital

On Oct. 26, 2009, we had approximately 198 million common shares outstanding.

At Sept. 30, 2009, we had 1.5 million outstanding employee stock options with a weighted average exercise price of $26.45. For the three and nine months ended Sept. 30, 2009, no options were exercised.

Normal Course Issuer Bid Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval from the Toronto Stock Exchange to purchase, for cancellation, up to 9.9 million of our common shares representing five per cent of our 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition.

For the three and nine months ended Sept. 30, 2009, no shares were purchased under the NCIB program.

Credit Risk Exposure

Credit risk exposure is the risk to our business associated with changes in creditworthiness of entities with which we have commercial exposures. Refer to page 55 of our 2008 Annual Report for further details on our credit risk management profile and practices.

While we had no counterparty losses in the third quarter of 2009, we continue to keep a close watch on changes and trends in the market and the impact these changes could have on our trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

We are exposed to minimal credit risk from our Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. Our credit risk management profile and practices have not changed materially since Dec. 31, 2008.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At Sept. 30, 2009, we provided letters of credit totalling $296 million (Dec. 31, 2008 – $430 million) and cash collateral of $26 million (Dec. 31, 2008 – $37 million). The decrease in letters of credit and cash collateral is due primarily to lower forward electricity prices in the Pacific Northwest and reduced trading activity with exchanges. These letters of credit and cash collateral secure certain amounts included on our balance sheet under “Risk Management Liabilities” and “Asset Retirement Obligations”.

CLIMATE CHANGE AND THE ENVIRONMENT

In the third quarter of 2009, there were no significant changes to environmental legislation affecting power generation in Canada. The federal government continues to develop its greenhouse gas (“GHG”) regulatory framework with the goal of having regulations in place by 2010 for implementation in 2012. However, announcement of the details have been delayed pending, in part, developments of the parallel U.S. framework.

Development of new Canadian air pollutant requirements for sulphur dioxide, nitrogen oxide (“NOx”) and mercury continues through a stakeholder consultation process involving industry, provincial and federal governments, and environmental organizations. There is currently no defined date for the finalization and implementation of any recommendations.

On Oct. 14, 2009, the federal and provincial governments announced that Project Pioneer, our CCS project, has received committed funding of more than $750 million. This funding is provided as part of the Government of Canada’s $1 billion Clean Energy Fund and the Government of Alberta’s $2 billion CCS initiative. The funding will support the undertaking of a Front End Engineering and Design (“FEED”) study that is expected to be complete in 2010.

Recent changes to environmental regulations may materially adversely affect us. As indicated under ‘‘Risk Factors’’ in the Annual Information Form, many of our activities and properties are subject to environmental requirements and changes in, or liabilities under, these requirements may materially adversely affect us. Since the date of the Annual Information Form, the state government of Washington has determined a target for our facilities in Centralia to reduce their GHG emissions by 50 per cent by 2025. Accomplishing this reduction will require some substantive change to generation technology, fuel or operation at those facilities prior to 2025. On Sept. 30, 2009, the United States Environmental Protection Agency proposed new regulations that would require additional permitting and possible controls or other reductions in GHGs from large industrial sources of carbon dioxide and other GHGs, including our facilities in Centralia. Due to the early stage of these regulatory programs, we cannot yet determine the impact from these programs if and when they become effective.

In September 2009, after the conclusion of a mediation process, we agreed to enter into a voluntary agreement with the Washington State Department of Ecology that will result in lower limits of oxides or nitrogen emissions and installation of mercury controls in 2012 in advance of enforceable U.S. federal or state requirements at our facilities in Centralia. We do not believe the costs of these programs will be material. The draft settlement agreement has been circulated for public comment.

OUTLOOK

For 2009, we now anticipate comparable earnings per share to be below last year's comparable earnings per share due to the move of the Sundance 3 major maintenance outage to 2009, higher OM&A due to our accelerated major maintenance program, lower availability, and poor hydro conditions. The other significant factors that influence our results are discussed below and exclude the impact of acquiring Canadian Hydro unless otherwise specified.

Business Environment

Economic Environment

As a result of the ongoing economic environment, commodity prices continue to be low, and could result in lower input costs for us in the future. Although we have contracted the price of the majority of our inputs in the short-term, in the longer-term we may see the benefit of lower operating costs.

A number of financial and industrial counterparties have experienced credit rating downgrades and we expect the balance of 2009 will continue to be challenging for some of our counterparties. While we had no counterparty losses in the first three quarters of 2009, we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Our strong financial position, available committed lines of credit, and relatively low debt maturity profile allows us to be selective about when we go to the market for financing. We also see continued support in capital markets for other projects that meet our return requirements.

While we do expect our results from operations in 2009 to be impacted by the current economic environment, this impact is somewhat mitigated by the contracted production and prices through our PPAs and other long-term contracts.

Spot Power Prices

For the remainder of 2009, spot power prices are expected to remain lower than 2008 due to lower natural gas prices and continued weakened demand for electricity.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has expressed its plan to coordinate its regulatory framework in time and stringency with the U.S. In the U.S., it is not clear if climate change legislation will prevail or if instead regulation will be applied by the EPA. Each of these outcomes could create widely different results for the energy industry in the U.S., and indirectly for Canada's regulatory approach.

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

Operations

Canadian Hydro Acquisition

As noted in the Subsequent Events section of this MD&A, we completed the acquisition and payment for approximately 87 percent of the outstanding common shares of Canadian Hydro. Planning of integration activities has commenced and we expect that we will be able to fully integrate Canadian Hydro's operations within a reasonable period of time.

Production, Availability, and Capacity

Generating capacity is expected to increase due to the uprate at Sundance Unit 5 in late 2009 and the completion of Blue Trail. Production and availability are expected to be higher in the fourth quarter due to lower planned and unplanned outages. Overall fleet availability for 2009 is expected to be between 86 and 87 per cent. The decrease in availability from the second quarter outlook is mainly due to the level of unplanned outages during the third quarter.

Commodity Hedging

Through the Alberta PPAs and our other long-term contracts, approximately 70 per cent of our capacity is contracted over the next 10 years. To provide further stability to future earnings, we enter into physical and financial contracts for periods of up to four years. Under this strategy, we target being up to 90 per cent contracted for the upcoming year, stepping down to 70 per cent in the fourth year. As at the end of the third quarter, more than 95 per cent of our 2009 remaining capacity and approximately 85 per cent of our 2010 capacity is contracted with the average contracted price in 2009 of $60-$65/MWh in Alberta and U.S.$50-$55/MWh in the Pacific Northwest.

We continue to closely monitor the risks associated with commodity price changes on our future operations and, where we consider appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Fuel Costs

Coal costs in Alberta are subject to increases related to mining such as increased overburden removal, inflation, and increases in commodity prices. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Although the risk of cost increases due to commodity prices is much lower, coal costs for the remainder of 2009, on a standard cost basis, are expected to remain flat compared to the prior year due to increased capital expenditures in 2008 being offset by cost savings and productivity initiatives in 2009.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for the remainder of 2009 is expected to increase between 10 and 15 per cent from the prior year due to rail and transportation contract escalations.

Our natural gas-fired facilities have minimal exposure to market fluctuations in energy commodity prices. Exposure to natural gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term natural gas purchase contracts. Merchant natural gas facilities are exposed to the changes in spark spreads because the majority of the natural gas is purchased and power is sold on a spot basis. The input costs that are purchased on a spot basis benefited from lower prices seen throughout the third quarter. We expect lower natural gas prices to continue for the remainder of 2009.

Operations, Maintenance, and Administration Costs

OM&A costs per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per installed MWh for the remainder of 2009 are expected to decrease as a result of lower planned maintenance activities, cost savings, and productivity initiatives. OM&A costs for the full year are expected to be $30-$40 million higher than last year due exclusively to higher major maintenance.

Energy Trading

Earnings from our COD segment are affected by prices in the market, the positions taken, and duration of those positions. We continuously monitor both the market and our exposure with the view to maximize earnings while still maintaining an acceptable risk profile. Our 2009 objective for Energy Trading is to contribute between $50 million and $70 million in gross margin.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar and Australian dollar by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign-denominated currency expenses, including interest charges, which serve as a natural hedge for a portion of our foreign currency revenues. Any residual foreign exchange exposure in the current year is hedged with foreign exchange contracts.

Net Interest Expense

Net interest expense for the remainder of 2009 is expected to be higher compared to the prior year mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar will 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, there may be the need for additional liquidity. To mitigate this liquidity risk, we maintain and monitor $2.1 billion of committed credit facilities as well as monitor exposures to determine expected liquidity requirements.

Accounting Estimates

Although we do not expect significant changes in our accounting estimates as a result of the current economic environment, some fluctuation could be seen on the fair valuation of our risk management assets and liabilities due to large variation in future commodity prices and foreign exchange and interest rate forward curves. Any significant changes in forward prices and rates could result in material differences in the amount of unrealized gains or losses and risk management assets and liabilities recorded at each reporting date due to the fair valuation performed at that time. However, any such change in fair value will not impact cash flow as we will continue to receive our contracted prices associated with Generation asset contracts.

Capital Expenditures

Projects and Growth

Our major projects are comprised of spending to sustain our current operations and for growth activities. Seven significant growth capital projects are currently in progress as outlined in the table below:

	Total Project		2009		Target	
Project	**Estimated spend**	**Incurred to date**	**Estimated spend**	**Incurred to date**	**completion date**	**Details**
Keephills 3	988	648	235 - 255	172	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power Corporation
Blue Trail	115	102	85 - 90	76	Q4 2009	A 66 MW wind farm in southern Alberta
Sundance Unit 5 uprate	80	60	55 - 65	43	Q4 2009	A 53 MW efficiency uprate at our Sundance facility
Summerview 2	123	84	80 - 90	59	Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	1	5 - 10	1	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	1	5 - 10	1	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	26	25 - 35	26	Q1 2011	A 69 MW wind farm in southern Alberta
Total growth	**1,509**	**922**	**490 - 555**	**378**		

Our estimate of total costs for Keephills 3 has increased by $100 million due to a change in our original expectations of the labour required to complete the project.

Our estimate for the total cost of the Sundance Unit 5 uprate has increased by $5 million due to the reclassification of some costs out of planned maintenance to more accurately reflect the type of work being done.

Sustaining Expenditures

For 2009, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Incurred to date
Routine capital	Expenditures to maintain our existing generating capacity	130 - 150	99
Productivity capital	Projects to improve power production efficiency	40 - 45	37
Mining equipment and land purchases	Expenditures related to mining equipment and land	35 - 45	28
Centralia modifications	Capital project to allow for usage of third party supplied coal	20 - 25	19
Planned maintenance	Regularly scheduled major maintenance	115 - 125	99
Total sustaining expenditures		**340 - 390**	**282**

The expected cost for routine capital has increased and the expected cost for planned maintenance has decreased due to the reclassification of some costs to more accurately reflect the type of work that has been completed to date and expectations for the remainder of the year, as well as the overall savings in our capital programs.

Details of the 2009 planned maintenance program are outlined as follows:

	Coal	Gas and hydro	Expected cost	Incurred to date
Capitalized	80 - 85	35 - 40	**115 - 125**	**99**
Expensed	115 - 125	0 - 5	**115 - 130**	**111**
	195 - 210	35 - 45	**230 - 255**	**210**

	Coal lost	Gas and hydro lost	Total lost	Lost to date
GWh lost	3,250 - 3,300	200 - 250	**3,450 - 3,550**	**3,375**

The expected GWh to be lost have increased compared to previous estimates to more accurately reflect the actual results to date and expectations for the remainder of the year.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity. The funds required for committed growth and sustaining projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flows and amount of committed credit available at Sept. 30, 2009.

RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Sept. 30, 2009, TAGP had received $48 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The total value of these contracts are U.S.$3 million per year for the years ending Dec. 31, 2009 and 2010.

For the period November 2002 to November 2012, one of our subsidiaries, TA Cogen, entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. We entered into an offsetting contract and therefore have no risk other than counterparty risk.

CURRENT ACCOUNTING CHANGES

Financial Instruments – Recognition and Measurement

On June 17, 2009, the Accounting Standards Board of Canada ("AcSB") released *Embedded Derivatives on Reclassification of Financial Assets*, amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendment indicates that contracts with embedded derivatives cannot be reclassified out of the held for trading category if the embedded derivative cannot be fair valued. The implementation of this standard did not have a material impact upon our consolidated financial statements.

Credit Risk

On Jan. 1, 2009, we adopted the Emerging Issues Committee ("EIC") Abstract 173 *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC–173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The implementation of this standard did not have a material impact upon our consolidated financial statements.

Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, we adopted Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 further defines that an internally developed intangible asset must demonstrate technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset in order to be able to capitalize associated costs. The implementation of this standard did not have a material impact upon our consolidated financial statements.

Mining Exploration Costs

On Jan. 1, 2009, we adopted EIC–174, *Mining Exploration Costs*. EIC–174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have a material impact upon our consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Financial Instruments Disclosures

On July 29, 2009, the AcSB released *Impairment of Financial Assets* amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendments changed the categories into which debt instruments could be classified and the impairment requirements for certain financial assets. Consequential amendments to Section 3025, *Impaired Loans,* were made to incorporate these changes. This standard will be effective for us for the annual period ending Dec. 31, 2009 and its adoption is not anticipated to have a material impact upon the consolidated financial statements.

In June 2009, the AcSB amended Section 3862*, Financial Instruments – Disclosures*, to converge with *Improving Disclosures about Financial Instruments (Amendments to International Financial Reporting Standard (IFRS 7*). The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. This standard will be effective for us for the annual period ending Dec. 31, 2009. It is not anticipated that the impacts of adopting this standard will be significant, as many of the expanded disclosure requirements are already provided as part of our existing financial instrument disclosures.

International Financial Reporting Standards ("IFRS") Convergence

On May 8, 2009, the AcSB re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. The project to convert to IFRS consists of four phases: diagnostic, design and planning, solution development, and implementation. The design and planning stage consists of cross-functional, issue-specific teams analyzing further the key areas of convergence, and along with Information Technology and Internal Control resources, determining process, system, and financial reporting controls changes required to effect dual reporting in 2010 and full convergence in 2011. The design and planning stage is essentially complete and the cross-functional teams are focusing on solution development activities. Staff training programs are underway and an internal communication plan is in place and is being carried out.

A steering committee monitors the progress and critical decisions in the transition to IFRS and continues to meet regularly. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources, and Operations. Quarterly updates are provided to the Audit and Risk Committee.

Based on work to-date, our view is that while IFRS uses a conceptual framework similar to Canadian GAAP and that while there are many similarities between Canadian GAAP and IFRS, there are several significant differences in accounting policies that must be addressed. The major differences for us will likely arise in respect of property, plant, and equipment, the impairment of long-lived assets, accounting for joint ventures, and accounting for long-term contracts. In addition, there is significantly more disclosure required, which is not anticipated to have a material impact upon our consolidated financial statements. We continue to carefully evaluate the transitional options available under IFRS at the adoption date, the most appropriate long-term accounting policies, and the impacts of the differences identified.

The International Accounting Standards Board ("IASB") is currently undertaking several IFRS projects which will likely result in significant changes to existing IFRS standards in areas such as financial statement presentation, leases, revenue recognition, post-employment benefits, taxes, and financial instruments. At this time, it is not anticipated that any material new standards or amendments relating to these projects will be effective on convergence in 2011. However, the progress and recommendations of these IASB projects are being monitored closely to ensure that any potential adverse impacts to the convergence project can be minimized. Accordingly, the full impact of adopting IFRS on our future financial position and future results cannot reasonably be determined at this time.

NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under GAAP and therefore should not be considered in isolation or as an alternative to or more meaningful than net income or cash flow from operating activities, as determined in accordance with GAAP, as an indicator of our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

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

Net Earnings Reconciliation

Gross margin and operating income are reconciled to net earnings below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Revenues	**666**	791	**2,007**	2,302
Fuel and purchased power	**(286)**	(393)	**(900)**	(1,095)
Gross margin	**380**	398	**1,107**	1,207
Operations, maintenance, and administration	**144**	161	**525**	474
Depreciation and amortization	**111**	108	**346**	312
Taxes, other than income taxes	**5**	5	**17**	15
Operating expenses	**260**	274	**888**	801
Operating income	**120**	124	**219**	406
Foreign exchange gain (loss)	**1**	(4)	**4**	(5)
Net interest expense	**(36)**	(33)	**(102)**	(101)
Equity loss	**-**	-	**-**	(97)
Other income	**-**	-	**8**	5
Earnings before non-controlling interests and income taxes	**85**	87	**129**	208
Non-controlling interests	**3**	15	**27**	38
Earnings before income taxes	**82**	72	**102**	170
Income tax expense	**16**	11	**-**	29
Net earnings	**66**	61	**102**	141

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Earnings on a comparable basis are based on earnings per share and are additive quarter over quarter.

In calculating comparable earnings for 2009, we have excluded the settlement of an outstanding commercial issue that has been recorded in other income as this was related to our previously held Mexican investment.

The change in life of certain component parts at Centralia Thermal was excluded from the calculation of comparable earnings in 2009 and 2008 as it relates to the cessation of mining activities at the Centralia coal mine and conversion to consuming solely third party supplied coal.

In calculating comparable earnings for 2008, we have also excluded the writedown of our Mexican investment. We also excluded the gains recorded on the sale of assets at the previously operated Centralia coal mine as we do not normally dispose of large quantities of fixed assets.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Net earnings	**66**	61	**102**	141
Sale of assets at Centralia, net of tax	**-**	-	**-**	(4)
Change in life of Centralia parts, net of tax	**-**	1	**1**	8
Settlement of commercial issue, net of tax	**-**	-	**(6)**	-
Writedown of Mexican investment, net of tax	**-**	-	**-**	65
Earnings on a comparable basis	**66**	62	**97**	210
Weighted average common shares outstanding in the period	**198**	198	**198**	199
Earnings on a comparable basis per share	**0.34**	0.32	**0.49**	1.06

Free Cash Flow (Deficiency)

Free cash flow is intended to demonstrate the amount of cash we have available to invest in capital growth initiatives, repay recourse debt, pay common share dividends, or repurchase common shares.

Sustaining capital expenditures for the three months ended Sept. 30, 2009, represents total additions to property, plant, and equipment per the Consolidated Statements of Cash Flow less $154 million ($153 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2008, we invested $213 million ($209 million net of joint venture contributions) in growth projects. For the nine months ended Sept. 30, 2009 and 2008, we invested $387 million ($378 million net of joint venture contributions) and $416 million ($401 million net of joint venture contributions), respectively, in growth projects.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Cash flow from operating activities	**194**	202	**334**	610
Add (Deduct):				
Sustaining capital expenditures	**(116)**	(97)	**(294)**	(294)
Dividends on common shares	**(58)**	(58)	**(169)**	(163)
Distribution to subsidiaries' non-controlling interest	**(7)**	(25)	**(40)**	(69)
Non-recourse debt repayments	**(1)**	(1)	**(19)**	(3)
Timing of contractually scheduled PPA payments	**-**	-	**-**	(116)
Other income	**-**	-	**(8)**	-
Cash flows from equity investments	**-**	(1)	**-**	2
Free cash flow (deficiency)	**12**	20	**(196)**	(33)

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

SELECTED QUARTERLY INFORMATION

	Q4 2008	Q1 2009	Q2 2009	**Q3 2009**
Revenue	808	756	585	**666**
Net earnings (loss)	94	42	(6)	**66**
Basic and diluted earnings (loss) per common share	0.47	0.21	(0.03)	**0.34**
Comparable earnings (loss) per share	0.40	0.18	(0.03)	**0.34**

	Q4 2007	Q1 2008	Q2 2008	Q3 2008
Revenue	783	803	708	791
Net earnings	130	33	47	61
Basic and diluted earnings per common share	0.64	0.17	0.24	0.31
Comparable earnings (loss) per share	0.51	0.50	0.25	0.32

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934 ("Exchange Act"), 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 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 are 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 was 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, the Corporation's internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Sept. 30, 2009, 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 document, documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as *"may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue"* or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause TransAlta's actual performance to be materially different from those projected.

Factors that may adversely impact our forward-looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate our facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) our provision for income taxes; (xvi) legal proceedings involving us; (xvii) reliance on key personnel; (xviii) labour relations matters; and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" on page 22 of our 2008 Annual Information Form and on page 53 of our 2008 Annual Report.

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 or might not occur. We cannot assure you that projected results or events will be achieved.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2009**	2008	**2009**	2008
Revenues	**666**	791	**2,007**	2,302
Fuel and purchased power	**(286)**	(393)	**(900)**	(1,095)
	380	398	**1,107**	1,207
Operations, maintenance, and administration	**144**	161	**525**	474
Depreciation and amortization *(Note 21)*	**111**	108	**346**	312
Taxes, other than income taxes	**5**	5	**17**	15
	260	274	**888**	801
	120	124	**219**	406
Foreign exchange gain (loss)	**1**	(4)	**4**	(5)
Net interest expense *(Note 9)*	**(36)**	(33)	**(102)**	(101)
Equity loss	**-**	-	-	(97)
Other income *(Note 11)*	**-**	-	**8**	5
Earnings before non-controlling interests and income taxes	**85**	87	**129**	208
Non-controlling interests *(Note 12)*	**3**	15	**27**	38
Earnings before income taxes	**82**	72	**102**	170
Income tax expense *(Note 7)*	**16**	11	**-**	29
Net earnings	**66**	61	**102**	141
Retained earnings				
Opening balance	**610**	640	**688**	763
Common share dividends	**(58)**	(53)	**(172)**	(161)
Common shares cancelled under NCIB *(Note 13)*	**-**	-	**-**	(95)
Closing balance	**618**	648	**618**	648
Weighted average number of common shares outstanding in the period	**198**	198	**198**	199
Net earnings per share, basic and diluted	**0.34**	0.31	**0.52**	0.71

See accompanying notes

TRANSALTA CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions of Canadian dollars)

Unaudited	Sept. 30, 2009	Dec. 31, 2008
		(Note 2)
Cash and cash equivalents *(Note 3)*	**86**	50
Accounts receivable *(Notes 3 and 19)*	**365**	505
Collateral paid *(Notes 2 and 3)*	**26**	37
Prepaid expenses	**13**	6
Risk management assets *(Notes 3, 4, and 5)*	**170**	200
Future income tax assets	**9**	3
Income taxes receivable	**70**	61
Inventory *(Note 6)*	**91**	51
	830	913
Restricted cash *(Note 3)*	**1**	-
Long-term receivables *(Note 10)*	**8**	14
Property, plant, and equipment		
Cost	**10,357**	9,932
Accumulated depreciation	**(4,106)**	(3,898)
	6,251	6,034
Goodwill *(Note 21)*	**133**	142
Intangible assets	**161**	213
Future income tax assets	**213**	248
Risk management assets *(Notes 3, 4, and 5)*	**206**	221
Other assets *(Note 8)*	**67**	39
Total assets	**7,870**	7,824
Accounts payable and accrued liabilities *(Note 3)*	**458**	667
Collateral received *(Notes 2 and 3)*	**107**	24
Risk management liabilities *(Notes 3, 4, and 5)*	**52**	148
Income taxes payable	**11**	15
Future income tax liabilities	**13**	14
Dividends payable	**55**	52
Current portion of long-term debt - recourse *(Notes 3 and 9)*	**212**	211
Current portion of long-term debt - non-recourse *(Notes 3 and 9)*	**28**	33
Current portion of asset retirement obligations *(Note 10)*	**48**	45
	984	1,209
Long-term debt - recourse *(Notes 3 and 9)*	**2,666**	2,332
Long-term debt - non-recourse *(Notes 3 and 9)*	**194**	232
Asset retirement obligations *(Note 10)*	**231**	252
Deferred credits and other long-term liabilities	**132**	122
Future income tax liabilities	**618**	596
Risk management liabilities *(Notes 3, 4, and 5)*	**48**	102
Non-controlling interests *(Note 12)*	**484**	469
Shareholders' equity		
Common shares *(Notes 13 and 14)*	**1,767**	1,761
Retained earnings *(Note 14)*	**618**	688
Accumulated other comprehensive income *(Note 14)*	**128**	61
Total shareholders' equity	**2,513**	2,510
Total liabilities and shareholders' equity	**7,870**	7,824

Contingencies *(Notes 17 and 19)*
Commitments *(Notes 4 and 18)*
Subsequent events *(Note 23)*

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 **2009**	2008	9 months ended Sept. 30 **2009**	2008
Net earnings	**66**	61	**102**	141
Other comprehensive (loss) income				
(Losses) gains on translating net assets of self-sustaining foreign operations	**(96)**	27	**(158)**	89
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1)	**72**	(22)	**103**	(92)
Gains on derivatives designated as cash flow hedges, net of tax(2)	**11**	441	**225**	53
Reclassification of derivatives designated as cash flow hedges to balance sheet, net of tax(3)	**-**	2	**(8)**	7
Reclassification of derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(38)**	35	**(95)**	58
Other comprehensive (loss) income	**(51)**	483	**67**	115
Comprehensive income	**15**	544	**169**	256

(1) Net of income tax expense of $12 million and $21 million for the three and nine months ended Sept. 30, 2009 (2008 - $5 million and $13 million recovery), respectively.

(2) Net of income tax recovery of $2 million and expense of $96 million for the three and nine months ended Sept. 30, 2009 (2008 - $246 million and $43 million expense), respectively.

(3) Net of income tax recovery of nil and $3 million for the three and nine months ended Sept. 30, 2009 (2008 - nil and $2 million expense), respectively.

(4) Net of income tax recovery of $21 million and $52 million for the three and nine months ended Sept. 30, 2009 (2008 - $14 million and $26 million expense), respectively.

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 **2009**	3 months ended Sept. 30 2008	9 months ended Sept. 30 **2009**	9 months ended Sept. 30 2008
Operating activities				
Net earnings	**66**	61	**102**	141
Depreciation and amortization *(Note 21)*	**116**	105	**359**	316
Gain on sale of equipment	**-**	-	**-**	(5)
Non-controlling interests	**3**	15	**27**	38
Asset retirement obligation accretion *(Note 10)*	**5**	5	**17**	16
Asset retirement costs settled *(Note 10)*	**(11)**	(14)	**(27)**	(26)
Future income taxes	**4**	(1)	**-**	(12)
Unrealized (gain) loss from risk management activities	**(1)**	(4)	**(1)**	11
Unrealized foreign exchange (gain) loss	**(4)**	4	**(15)**	5
Equity loss	**-**	-	**-**	97
Other non-cash items	**-**	4	**1**	(2)
	178	175	**463**	579
Change in non-cash operating working capital balances	**16**	27	**(129)**	31
Cash flow from operating activities	**194**	202	**334**	610
Investing activities				
Additions to property, plant, and equipment	**(269)**	(306)	**(681)**	(695)
Proceeds on sale of property, plant, and equipment	**4**	5	**5**	26
Proceeds on sale of minority interest in Kent Hills *(Note 11)*	**-**	-	**29**	-
Restricted cash	**1**	2	**(1)**	247
Income tax receivable	**-**	(8)	**-**	(8)
Realized (losses) gains on financial instruments	**(2)**	14	**(16)**	37
Loan to equity investment	**-**	-	**-**	(245)
Net (decrease) increase in collateral received from counterparties	**(15)**	-	**105**	-
Net decrease in collateral paid to counterparties	**2**	-	**9**	-
Settlement of adjustments on sale of Mexican investment	**-**	-	**(7)**	-
Other	**9**	1	**(5)**	12
Cash flow used in investing activities	**(270)**	(292)	**(562)**	(626)
Financing activities				
Net increase in credit facilities	**182**	308	**300**	107
Repayment of long-term debt	**(2)**	(110)	**(20)**	(240)
Issuance of long-term debt	**-**	-	**200**	502
Dividends paid on common shares	**(58)**	(58)	**(169)**	(163)
Funds paid to repurchase common shares under NCIB *(Note 14)*	**-**	(4)	**-**	(130)
Realized (losses) gains on financial instruments	**-**	(1)	**-**	12
Distributions paid to subsidiaries' non-controlling interests	**(7)**	(25)	**(40)**	(69)
Other	**(5)**	(1)	**(5)**	12
Cash flow from financing activities	**110**	109	**266**	31
Cash flow from operating, investing, and financing activities	**34**	19	**38**	15
Effect of translation on foreign currency cash	**(2)**	(3)	**(2)**	-
Increase in cash and cash equivalents	**32**	16	**36**	15
Cash and cash equivalents, beginning of period	**54**	50	**50**	51
Cash and cash equivalents, end of period	**86**	66	**86**	66
Cash taxes paid (recovered)	**3**	(8)	**35**	52
Cash interest paid	**12**	8	**78**	75

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. ACCOUNTING POLICIES

These unaudited interim consolidated financial statements do not include all of the disclosures included in TransAlta Corporation's ("TransAlta" or "the Corporation") annual consolidated financial statements. Accordingly, these unaudited interim consolidated financial statements should be read in conjunction with the Corporation's most recent annual consolidated financial statements.

These unaudited interim 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 the 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 consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") using the same accounting policies as those used in the Corporation's most recent annual consolidated financial statements, except as explained below.

2. ACCOUNTING CHANGES

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

Classification of Collateral

During 2009, collateral paid to counterparties was reclassified on the Consolidated Balance Sheets from accounts receivable to collateral paid in order to be presented separately. In 2008, $37 million was also reclassified in order to present comparable figures.

During 2009, collateral received from counterparties was reclassified on the Consolidated Balance Sheets from accounts payable to collateral received in order to be presented separately. In 2008, $24 million was also reclassified in order to present comparable figures.

Classification of Debt

The Corporation's credit facilities extend for more than one year, and as a result the outstanding balance of the Corporation's credit facilities have been reclassified from short-term debt to recourse long-term debt on the Consolidated Balance Sheets. In 2008, $443 million was reclassified in order to present comparable figures.

Current Accounting Changes

Financial Instruments – Recognition and Measurement

On June 17, 2009, the Accounting Standards Board of Canada ("AcSB") released *Embedded Derivatives on Reclassification of Financial Assets,* amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendment indicates that contracts with embedded derivatives cannot be reclassified out of the held for trading category if the embedded derivative cannot be fair valued. The implementation of this standard did not have a material impact upon the consolidated financial statements.

Credit Risk

On Jan. 1, 2009, the Corporation adopted the Emerging Issues Committee ("EIC") Abstract 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC–173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Disclosure required as a result of adopting this standard can be found in Note 4.

Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, the Corporation adopted Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 further defines that an internally developed intangible asset must demonstrate technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset in order to be able to capitalize associated costs. The implementation of this standard did not have a material impact upon the consolidated financial statements.

Mining Exploration Costs

On Jan. 1, 2009, the Corporation adopted EIC–174, *Mining Exploration Costs.* EIC–174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have a material impact upon the consolidated financial statements.

Future Accounting Changes

Financial Instruments – Disclosures

On July 29, 2009, the AcSB released *Impairment of Financial Assets*, amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendments changed the categories into which debt instruments could be classified and the impairment requirements for certain financial assets. Consequential amendments to Section 3025, *Impaired Loans,* were made to incorporate these changes. This standard will be effective for TransAlta for the annual period ending Dec. 31, 2009 and its adoption is not anticipated to have a material impact upon the consolidated financial statements.

In June 2009, the AcSB amended Section 3862, *Financial Instruments – Disclosures*, to converge with *Improving Disclosures about Financial Instruments (Amendments to IFRS 7)*. The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. This standard will be effective for TransAlta for the annual period ending Dec. 31, 2009. It is not anticipated that the impacts of adopting this standard will be significant, as many of the expanded disclosure requirements are already provided as part of the Corporation's existing financial instrument disclosures.

IFRS ("International Financial Reporting Standards") Convergence

On May 8, 2009, the AcSB re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that will be addressed as part of the convergence project. The project is on track and is currently in the solution development and implementation phase. Cross-functional, issue-specific teams have been established to analyze the impacts of adopting IFRS, and focus on developing and implementing specific solutions for convergence.

A steering committee, comprised of senior representatives across the Corporation, has been established to monitor the progress and critical decisions in the transition to IFRS, and continues to meet regularly. Quarterly updates are provided to the Audit and Risk Committee. The Corporation is continuing to assess the impact of adopting these standards on the consolidated financial statements.

3. FINANCIAL INSTRUMENTS

A. Analysis of Financial Assets and Liabilities by Measurement Basis

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost. The disclosures in the "Financial Instruments and Hedges" section of Note 1(N) to the Corporation's 2008 annual consolidated financial statements describe how the categories of financial instruments are measured and how income and expenses, including fair value gains and losses, are recognized. The following table classifies the carrying amounts of the financial assets and liabilities by category:

Carrying value of financial instruments as at Sept. 30, 2009

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	86	-	86
Accounts receivable	-	-	365	-	365
Collateral paid	-	-	26	-	26
Risk management assets					
Current	143	27	-	-	170
Long-term	201	5	-	-	206
Restricted cash	-	-	1	-	1
Financial liabilities			.		
Accounts payable and accrued liabilities	-	-	-	458	458
Collateral received	-	-	-	107	107
Risk management liabilities					
Current	28	24	-	-	52
Long-term	44	4	-	-	48
Long-term debt - recourse(1)	-	-	-	2,878	2,878
Long-term debt - non-recourse(1)	-	-	-	222	222

Carrying value of financial instruments as at Dec. 31, 2008

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	50	-	50
Accounts receivable	-	-	505	-	505
Collateral paid	-	-	37	-	37
Risk management assets					
Current	121	79	-	-	200
Long-term	220	1	-	-	221
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	667	667
Collateral received	-	-	-	24	24
Risk management liabilities					
Current	74	74	-	-	148
Long-term	96	6	-	-	102
Long-term debt - recourse(1)	-	-	-	2,543	2,543
Long-term debt - non-recourse(1)	-	-	-	265	265

(1) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. In limited circumstances, the Corporation uses inputs that are not based on observable market data.

I. Level Determinations and Classifications

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined as follows:

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 Energy Trading fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange ("NYMEX").

Level II

Fair values are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly or indirectly.

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers in Level II. Level II fair values also include fair values 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.

Level III

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

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles, and/or volatilities and correlations between products derived from historical prices.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value.

The fair values of the Corporation's financial assets and liabilities are outlined below:

As at Sept. 30, 2009	Fair value (1) Level I	Level II	Level III	Total	Total carrying value
Financial assets and liabilities measured at fair value					
Net risk management assets (2)	-	272	4	276	276
Financial assets and liabilities measured at other than fair value					
Long-term debt	-	3,136	-	3,136	3,100

As at Dec. 31, 2008	Fair value (1) Level I	Level II	Level III	Total	Total carrying value
Financial assets and liabilities measured at fair value					
Net risk management assets (2)	1	170	-	171	171
Financial assets and liabilities measured at other than fair value					
Long-term debt	-	2,542	-	2,542	2,808

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, collateral paid, accounts payable, collateral received, and accrued liabilities).

(2) Includes Energy Trading and Other Risk Management Assets and Liabilities on a net basis (Note 4).

II. Fair Values Determined Using Valuation Models (Levels II & III)

Fair values determined using valuation models require the use of assumptions. Where assumptions and inputs are based on readily observable market data, the fair values are categorized as Level II. The key inputs to valuation models and regression or extrapolation formulas include interest rate yield curves, currency rates, credit spreads, implied volatilities, and commodity prices for similar assets or liabilities in active markets, as applicable.

Where the fair values have been developed using valuation models based on unobservable or internally developed assumptions or inputs (Level III Energy Trading Risk Management fair values), the key inputs include historical data such as plant performance, volatilities and correlations between products derived from historical prices, congestion on transmission paths, or demand profiles for individual non-standard deals and structured products.

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 Sept. 30, 2009 is estimated to be +/- $1 million (Dec. 31, 2008 – nil). This estimate is based on a +/- one standard deviation move from the mean.

The total change in fair value estimated using a valuation technique with unobservable inputs, for financial assets and liabilities measured and recorded at fair value, that was recognized in pre-tax earnings for the nine months ended Sept. 30, 2009 was $1 million (Sept. 30, 2008 – $16 million gain). A reconciliation of the movements in Risk Management fair values by Level, as well as additional Level III gain (loss) information can be found in Note 4.

C. Inception Gains and Losses

The majority of the Corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange requiring the use of internal valuation techniques or models.

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 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 Balance Sheet in Energy Trading Risk Management Assets or Liabilities, and is recognized in earnings over the term of the related contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the period is as follows:

As at	**Sept. 30, 2009**	Sept. 30, 2008
Unamortized gain at beginning of period	**2**	3
Amortization recorded in earnings	**(2)**	(2)
Unamortized gain at end of period	**-**	1

D. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk – Proprietary Trading

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. Value at Risk ("VaR") at Sept. 30, 2009 associated with the Corporation's proprietary trading activities was $5 million (Dec. 31, 2008 – $6 million).

b. Commodity Price Risk - Generation

VaR at Sept. 30, 2009 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $53 million (Dec. 31, 2008 – $86 million).

The Corporation's policy on asset-backed transactions is to seek normal purchase / normal sale ("NPNS") contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions, such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2009 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was nil (Dec. 31, 2008 – nil).

c. Interest Rate Risk

The possible effect on pre-tax earnings and Other Comprehensive Income ("OCI"), due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading and hedging interest rate derivatives outstanding at the Consolidated Balance Sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is a reasonable potential change in market interest rates over the next quarter and is consistent with a +/- one standard deviation move from the mean.

	9 months ended Sept. 30			
	2009		2008	
	Net earnings increase (1)	**OCI loss (1)**	Net earnings increase (1)	OCI loss (1)
50 basis point change	3	(8)	3	-

(1) This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.

d. Currency Risk

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on pre-tax earnings and OCI, due to changes in foreign exchange rates associated with financial instruments outstanding at the Consolidated Balance Sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is consistent with a +/- one standard deviation move from the mean.

	9 months ended Sept. 30			
	2009		2008	
Currency	**Net earnings decrease (1)**	**OCI gain (1), (2)**	Net earnings decrease (1)	OCI gain (1), (2)
Euro	-	-	-	2
U.S.	(1)	2	(1)	2
AUD	(2)	-	(2)	-
Total	(3)	2	(3)	4

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments used as the hedging instruments in the net investment hedges have been excluded.

II. Credit Risk

At Sept. 30, 2009, TransAlta did not have any counterparties whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at the end of the period.

The Corporation's maximum exposure to credit risk at Sept. 30, 2009 and at Dec. 31, 2008, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. 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 customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading, net of any collateral held, at Sept. 30, 2009 was $48 million (Dec. 31, 2008 – $105 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at Sept. 30, 2009:

	Investment grade	**Non-investment grade**	**Total**
	%	**%**	**%**
Accounts receivable	92	8	100
Risk management assets	100	-	100

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the period is presented below:

As at	**Sept. 30, 2009**	Dec. 31, 2008
Allowance at beginning of period	**57**	46
Change in foreign exchange rates	**(7)**	11
Allowance at end of period	**50**	57

At Sept. 30, 2009, the Corporation did not have any significant past due trade receivables.

III. Liquidity Risk

A maturity analysis for the Corporation's financial assets and liabilities is as follows:

	2009	**2010**	**2011**	**2012**	**2013**	**2014 and thereafter**	**Total**
Accounts payable and accrued liabilities	458	-	-	-	-	-	458
Collateral received	107	-	-	-	-	-	107
Debt (1)	220	29	252	772	678	1,152	3,103
Energy Trading risk management assets (2)	(49)	(77)	(80)	(70)	(10)	-	(286)
Other risk management (assets) liabilities (3)	(1)	11	(8)	-	-	8	10
Interest on long-term debt	45	147	135	116	102	547	1,092
Total	780	110	299	818	770	1,707	4,484

(1) Excludes impact of hedge accounting.

(2) Energy Trading risk management assets are comprised of net risk management assets and liabilities, where the net result is an asset (Note 4).

(3) Other risk management assets and liabilities are comprised of net risk management assets and liabilities (Note 4).

E. Financial Assets Provided as Collateral

At Sept. 30, 2009, $76 million (Dec. 31, 2008 – $63 million) of financial assets, consisting of bank accounts and accounts receivable, related to the Corporation's proportionate share of CE Generation, LLC ("CE Gen") have been pledged as collateral for certain CE Gen debt. Should any defaults occur, the debt-holders would have first claim on these assets.

At Sept. 30, 2009, the Corporation provided $26 million (Dec. 31, 2008 – $37 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

F. Financial Assets Held as Collateral

At Sept. 30, 2009, the Corporation received $107 million (Dec. 31, 2008 – $24 million) in cash collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

G. Gains and Losses on Financial Instruments

The Corporation's Commercial Operations & Development ("COD") segment utilizes a variety of derivatives in its proprietary trading activities, including certain commodity hedging activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the three months ended Sept. 30, 2009, the COD segment recognized a net unrealized gain of $1 million (Sept. 30, 2008 – $3 million net unrealized loss). For the nine months ended Sept. 30, 2009, the COD segment recognized a net unrealized loss of nil (Sept. 30, 2008 – $2 million net unrealized gain).

The Corporation's Generation segment utilizes a variety of derivatives in its operations, including certain commodity hedges that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the three months ended Sept. 30, 2009, the Generation segment recognized a net unrealized gain of nil (Sept. 30, 2008 – $8 million net unrealized gain). For the nine months ended Sept. 30, 2009, the Generation segment recognized a net unrealized gain of $1 million (Sept. 30, 2008 – $11 million net unrealized loss).

Net interest expense as reported on the Consolidated Statements of Earnings includes interest income and expense, respectively, on the Corporation's interest-bearing financial assets, primarily cash and restricted cash, and its interest-bearing financial liabilities, primarily short- and long-term debt. Interest expense is calculated using the effective interest rate method *(Note 9)*. Interest rate derivatives that are not designated as hedges are classified as held for trading and are marked-to-market each reporting period with the net gain or loss recorded in net interest expense.

Foreign exchange derivatives that are not designated as hedges are also classified as held for trading, with the net foreign exchange gain or loss on Energy Trading derivatives recorded in revenue, and the net gain or loss on other foreign exchange derivatives recorded in foreign exchange gain or loss on the Consolidated Statements of Earnings.

Other derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss recorded in operations, maintenance, and administration expense. Other derivatives consist of a total return swap that fixes a portion of the settlement cost of certain employee compensation and deferred share unit programs. The total return swap is cash settled every quarter.

The table below summarizes the net realized and unrealized gains and losses included in net earnings that are associated with derivatives not designated as hedges:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Losses on interest rate derivatives	**-**	(1)	**(1)**	(3)
Gains on foreign exchange derivatives	**3**	10	**2**	7
Losses on other derivatives	**-**	-	**(1)**	-

4. RISK MANAGEMENT ASSETS AND LIABILITIES

Aggregate risk management assets and liabilities are as follows:

As at	**Sept. 30, 2009**			Dec. 31, 2008		
Balance Sheet - Totals	**Energy Trading**	**Other**	**Total**	Energy Trading	Other	Total
Risk management assets						
Current	**165**	**5**	**170**	176	24	200
Long-term	**186**	**20**	**206**	187	34	221
Risk management liabilities						
Current	**40**	**12**	**52**	142	6	148
Long-term	**25**	**23**	**48**	57	45	102
Net risk management assets (liabilities)	**286**	**(10)**	**276**	164	7	171

Energy Trading

The risk management assets and liabilities related to Energy Trading are as follows:

As at	**Sept. 30, 2009**			Dec. 31, 2008
Balance Sheet - Energy Trading	**Hedges**	**Non-hedges**	**Total**	Total
Risk management assets				
Current	**141**	**24**	**165**	176
Long-term	**181**	**5**	**186**	187
Risk management liabilities				
Current	**19**	**21**	**40**	142
Long-term	**21**	**4**	**25**	57
Net risk management assets	**282**	**4**	**286**	164

The following table summarizes the key factors impacting the fair value of the Corporation's Energy Trading net risk management assets and liabilities separately by source of valuation during the nine months ended Sept. 30, 2009:

	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, 2008	-	163	-	1	-	-	1	163	-
Changes attributable to:									
Commodity price changes	-	149	-	-	-	-	-	149	-
New contracts entered	-	21	-	-	(2)	1	-	19	1
Contracts settled	-	(30)	-	(1)	5	-	(1)	(25)	-
Change in foreign exchange rates	-	(21)	-	-	-	-	-	(21)	-
Transfers in/out of Level III	-	(3)	3	-	-	-	-	(3)	3
Net risk management assets (liabilities) at Sept. 30, 2009	**-**	**279**	**3**	**-**	**3**	**1**	**-**	**282**	**4**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			3			-			3
Change in fair value included in earnings before income taxes			-			1			1
Change in fair value included in earnings before income taxes relating to those net assets (liabilities) held at Sept. 30, 2009			-			1			1

To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of the COD and Generation business segments.

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

		2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	43	77	79	70	10	-	**279**
	Level III	1	1	1	-	-	-	**3**
Non-hedges	Level I	-	-	-	-	-	-	**-**
	Level II	4	(1)	-	-	-	-	**3**
	Level III	1	-	-	-	-	-	**1**
Total by level	Level I	-	-	-	-	-	-	**-**
	Level II	47	76	79	70	10	-	**282**
	Level III	2	1	1	-	-	-	**4**
Total net assets		**49**	**77**	**80**	**70**	**10**	**-**	**286**

The Corporation's outstanding Energy Trading derivative financial instruments at Sept. 30, 2009 are summarized below:

Units (000s)	Electricity (MWh)	Natural gas (GJ)	Transmission (MWh)	Coal (tonnes)	Emissions (tonnes)	Oil (gallons)
Derivative financial instruments designated as hedges						
Notional Amounts						
Purchases	-	2,056	-	-	-	22,092
Sales	25,571	-	-	-	-	-
Derivative financial instruments held for trading (non-hedges)						
Notional Amounts						
Purchases	14,572	189,070	230	98	175	-
Sales	14,269	198,891	-	98	175	-

Other Risk Management Assets and Liabilities

The risk management assets and liabilities related to other non-Energy Trading are as follows:

As at	Sept. 30, 2009			Dec. 31, 2008
Balance Sheet - Other	**Hedges**	**Non-hedges**	**Total**	Total
Risk management assets				
Current	**2**	**3**	**5**	24
Long-term	**20**	**-**	**20**	34
Risk management liabilities				
Current	**9**	**3**	**12**	6
Long-term	**23**	**-**	**23**	45
Net risk management (liabilities) assets	**(10)**	**-**	**(10)**	7

The following table summarizes the key factors impacting the fair value of the Corporation's other net risk management assets and liabilities during the nine months ended Sept. 30, 2009:

	Hedges	Non-hedges	Total
Net risk management assets (liabilities) at Dec. 31, 2008	8	(1)	7
Changes attributable to:			
Market price changes	(13)	-	(13)
New contracts entered	(31)	-	(31)
Contracts settled	26	1	27
Net risk management (liabilities) assets at Sept. 30, 2009	**(10)**	-	**(10)**

Changes in non-Energy risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. So as long as these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument or reduction in the net investment in the foreign operations.

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

	2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	(1)	(9)	8	-	-	(8)	**(10)**
Non-hedges	2	(2)	-	-	-	-	**-**
Total net assets (liabilities)	**1**	**(11)**	**8**	**-**	**-**	**(8)**	**(10)**

Additional information related to other risk management assets and liabilities designated as hedges and non-hedges are outlined below:

A. Hedges

I. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$1,100 million (Dec. 31, 2008 – U.S.$1,100 million), and a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2008 – U.S.$238 million) have been designated as a part of the hedge of TransAlta's net investment in self-sustaining foreign operations.

The Corporation has also hedged a portion of its net investment in self-sustaining foreign operations with cross-currency interest rate swaps and foreign currency forward sales (purchase) contracts as shown below:

a. Cross-Currency Interest Rate Swap

Outstanding asset (liability) resulting from cross-currency interest rate swap is as follows:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value asset	Maturity
AUD34	**(2)**	**2010**	AUD34	2	2009

b. Foreign Currency Contracts

Outstanding foreign currency forward sales (purchase) contracts are as follows:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value (liability) asset**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD110	**(1)**	**2009**	AUD108	(1)	2009
U.S.(161)	**2**	**2009**	U.S.(107)	(1)	2009

II. Hedges of Future Foreign Currency Obligations

TransAlta's future foreign currency obligations are primarily related to foreign denominated capital asset purchases. The Corporation has hedged a portion of these obligations through forward purchase contracts as follows:

Sept. 30, 2009				Dec. 31, 2008			
Amount sold	**Amount purchased**	**Fair value (liability) asset**	**Maturity**	Amount sold	Amount purchased	Fair value asset	Maturity
87	**U.S.74**	**(7)**	**2010**	51	U.S.48	8	2009-2010
U.S.13	**15**	**-**	**2010**	-	-	-	-
AUD4	**U.S.3**	**-**	**2010**	-	-	-	-
EUR1	**U.S.1**	**-**	**2009**	-	-	-	-
U.S.1	**EUR1**	**-**	**2009**	-	-	-	-
1	**EUR0**	**-**	**2009**	84	EUR57	13	2009

III. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 6.6 per cent to 6.65 per cent, to floating rate debt through interest rate swaps as shown below:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
100	**8**	**2011**	100	12	2011
U.S.100	**12**	**2018**	U.S.100	21	2018

Including the interest rate swaps above, 30 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2008 – 24 per cent).

The Corporation also has an outstanding forward start interest rate swap that converts floating rate debt into fixed rate debt. The commencement date for this swap is March 5, 2010, with fixed rates ranging from 3.5 per cent to 4.6 per cent, as shown below:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
U.S.300	**(22)**	**2020**	U.S.300	(46)	2019

B. Non-Hedges

I. Cross-Currency Interest Rate Swaps

Cross-currency interest rate swaps are periodically entered into in order to limit the Corporation's exposure to fluctuations in foreign exchange and interest rates. The asset (liability) resulting from an outstanding cross-currency interest rate swap is as follows:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value asset	Maturity
AUD21	**(3)**	**2010**	AUD41	1	2009

II. Foreign Exchange Forward Contracts and Total Return Swaps

The Corporation periodically enters into foreign exchange forwards to hedge future foreign denominated revenues and expenses for which hedge accounting is not pursued. These items are classified as held for trading, and changes in the fair values associated with these transactions are recognized in net earnings.

Outstanding notional amounts and fair values with these forward sales (purchases) are as follows:

Sept. 30, 2009			Dec. 31, 2008		
Notional amount	**Fair value (liability) asset**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD7	**-**	**2009**	-	-	-
U.S.30	**3**	**2010**	U.S.90	(2)	2009

The Corporation also has certain compensation and deferred share units programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been chosen. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter *(Note 3)*.

C. Contingent Features in Derivative Instruments

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

As at Sept. 30, 2009 the Corporation had posted collateral of $25 million in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at Sept. 30, 2009, the Corporation would be required to post an additional $32 million of collateral to its counterparties.

5. HEDGING ACTIVITIES

Fair Value Hedges

No ineffective portion of fair value hedges was recorded for the three and nine months ended Sept. 30, 2009.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings for the three and nine months ended Sept. 30, 2009:

Derivatives in fair value hedging relationships	**Location of gain (loss) on statements of earnings**	**3 months ended Sept. 30, 2009**	**9 months ended Sept. 30, 2009**
Interest rate contracts	Interest expense	**(1)**	**13**
Long-term debt	Interest expense	**1**	**(13)**
Net earnings impact		**-**	**-**

Cash Flow Hedges

Forward sale and purchase contracts, as well as foreign exchange contracts, are used to hedge the variability in future cash flows. All components of each derivative's change in fair value have been included in the assessment of cash flow hedge effectiveness.

For the three months ended Sept. 30, 2009, a pre-tax unrealized gain of $9 million (Sept. 30, 2008 – pre-tax unrealized gain of $687 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $59 million (Sept. 30, 2008 – $49 million) in amounts previously related to OCI was reclassified to net earnings.

For the nine months ended Sept. 30, 2009, a pre-tax unrealized gain of $321 million (Sept. 30, 2008 – pre-tax unrealized gain of $96 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $147 million (Sept. 30, 2008 – $85 million) in amounts previously related to OCI was reclassified to net earnings.

For the three months ended Sept. 30, 2009, a realized gain of $1 million (Sept. 30, 2008 – loss of $4 million) was recognized in earnings for the ineffective portion. For the nine months ended Sept. 30, 2009, a realized loss of $2 million (Sept. 30, 2008 – loss of $5 million) was realized in earnings for the ineffective portion.

Over the next 12 months, the Corporation estimates that $82 million (Dec. 31, 2008 – $17 million) of after-tax gains will be reclassified from Accumulated Other Comprehensive Income ("AOCI") and recognized in earnings.

The following tables summarize the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets for the three and nine months ended Sept. 30, 2009:

3 months ended Sept. 30, 2009

Effective portion				Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of gain (loss) reclassified from OCI**	**Pre-tax gain (loss) reclassified from OCI**	**Location of gain (loss) recognized in earnings**	**Pre-tax gain (loss) recognized in earnings**
Interest rate	**58**	Interest expense	**1**	Interest expense	**(1)**
Foreign exchange	**(25)**	Foreign exchange gain (loss)	**-**	Revenue	**2**
		Property, plant, and equipment	**-**		
Commodity	**(24)**	Revenue	**(60)**		
OCI impact	**9**	**OCI impact**	**(59)**	**Net earnings impact**	**1**

9 months ended Sept. 30, 2009

Effective portion				Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of gain (loss) reclassified from OCI**	**Pre-tax gain (loss) reclassified from OCI**	**Location of loss recognized in earnings**	**Pre-tax loss recognized in earnings**
Interest rate	**24**	Interest expense	**1**	Interest expense	**(2)**
Foreign exchange	**(15)**	Foreign exchange gain (loss)	**-**	Revenue	**-**
		Property, plant, and equipment	**(11)**		
Commodity	**312**	Revenue	**(148)**		
OCI impact	**321**	**OCI impact**	**(158)**	**Net earnings impact**	**(2)**

Net Investment Hedges

For the three months ended Sept. 30, 2009, a net after-tax loss of $24 million (Sept. 30, 2008 – gain of $5 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI. For the nine months ended Sept. 30, 2009, a net after-tax loss of $55 million (Sept. 30, 2008 – loss of $3 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income for the three and nine months ended Sept. 30, 2009:

Derivatives in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI for the 3 months ended Sept. 30, 2009	Pre-tax gain (loss) recognized in OCI for the 9 months ended Sept. 30, 2009
Foreign exchange	(16)	(57)
Cross currency	(1)	(4)
Long-term debt	101	185
OCI impact	**84**	**124**

Summary

The following table summarizes the fair values of derivative instruments categorized by their hedging relationships, as well as derivatives that are not designated as hedges:

As at	Sept. 30, 2009					Dec. 31, 2008
	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated as a Hedge	Total	Total
Financial derivative assets	20	322	2	32	376	421
Financial derivative liabilities	-	62	10	28	100	250

6. INVENTORY

Inventory includes coal, natural gas fuels, and emission credits which are valued at the lower of cost and net realizable value. The classifications are as follows:

As at	Sept. 30, 2009	Dec. 31, 2008
Coal	86	45
Natural gas	5	5
Purchased emission credits	-	1
Total	**91**	51

The increase in coal inventory at Sept. 30, 2009 compared to Dec. 31, 2008 is primarily due to lower production at the Centralia and Alberta Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2008	51
Net additions	44
Change in foreign exchange rates	(4)
Balance, Sept. 30, 2009	**91**

No inventory is pledged as security for liabilities.

For the three and nine months ended Sept. 30, 2009, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into earnings.

7. INCOME TAX EXPENSE

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Current tax expense	**12**	12	**-**	41
Future income tax (recovery)	**4**	(1)	**-**	(12)
Income tax expense	**16**	11	**-**	29

8. OTHER ASSETS

The components of other assets are as follows:

As at	**Sept. 30, 2009**	Dec. 31, 2008
Deferred license fees	**22**	21
Accrued pension benefit asset	**16**	9
Project development costs	**4**	4
Growth and productivity costs	**10**	-
Keephills 3 transmission deposit	**8**	-
Other	**7**	5
Other assets	**67**	39

Growth and productivity costs include financing costs related to debt facilities established to support the acquisition of Canadian Hydro Developers. The Keephills 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit for Keephills 3. The full amount of the deposit is anticipated to be reimbursed over the next 10 years, as long as certain performance criteria are met.

9. LONG-TERM DEBT AND NET INTEREST EXPENSE

As at	**Sept. 30, 2009**			Dec. 31, 2008		
	Carrying value	**Face value**	**Interest (1)**	Carrying value	Face value	Interest (1)
Credit facilities (2)	**744**	**744**	**0.9%**	443	443	2.8%
Debentures	**885**	**881**	**6.8%**	682	681	6.8%
Senior notes (2009 - U.S.$1,100 million, 2008 - U.S.$1,100 million)	**1,187**	**1,194**	**6.3%**	1,352	1,344	6.3%
Non-recourse (2009 - U.S.$204 million, 2008 - U.S.$219 million)	**222**	**222**	**7.5%**	265	265	7.4%
Other	**62**	**62**	**6.8%**	66	66	6.7%
	3,100	**3,103**		2,808	2,799	
Less: current portion	**(240)**	**(240)**		(244)	(244)	
Total long-term debt	**2,860**	**2,863**		2,564	2,555	

(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.

On May 29, 2009, the Corporation issued debentures in the amount of $200 million. These debentures bear interest at a rate of 6.45 per cent and mature in 2014.

The Corporation has converted $100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of interest rate swaps. These interest rate swaps mature in June 2011 *(Note 4)*.

The Corporation has converted U.S.$100 million fixed interest rate debt with a rate of 6.65 per cent to floating rates through the use of interest rate swaps. These interest rate swaps mature in May 2018 *(Note 4)*.

The components of net interest expense are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2009	2008	**2009**	2008
Interest on long-term debt	**46**	45	**132**	129
Interest income	**(3)**	(6)	**(6)**	(15)
Capitalized interest	**(10)**	(6)	**(27)**	(13)
Other	**3**	-	**3**	-
Net interest expense	**36**	33	**102**	101

The Corporation capitalizes interest during the construction phase of growth capital projects.

10. ASSET RETIREMENT OBLIGATIONS

The change in the asset retirement obligation balances is summarized below:

Balance, Dec. 31, 2008	297
Liabilities incurred	2
Liabilities settled	(27)
Accretion expense	17
Revisions in estimated cash flows	3
Change in foreign exchange rates	(13)
	279
Less: current portion	(48)
Balance, Sept. 30, 2009	**231**

The Corporation has a right to recover a portion of future asset retirement costs. The estimated present value of these recoveries has been recorded as a long-term receivable.

11. OTHER INCOME

During the second quarter of 2009, the Corporation sold 17 per cent of its Kent Hills project to Natural Forces Technologies Inc. for proceeds of $29 million, and recorded a pre-tax gain of $1 million. During the first quarter of 2009, the Corporation settled an outstanding commercial issue for a pre-tax gain of $7 million.

During the first quarter of 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million.

12. NON-CONTROLLING INTERESTS

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2008	469
Distributions paid	(40)
Non-controlling interest portion of net earnings	27
Minority interest in Kent Hills *(Note 11)*	28
As at Sept. 30, 2009	**484**

The earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2009 decreased $12 million and $11 million, respectively, due to lower earnings at CE Gen as a result of the expiration of the PPA between TransAlta's Saranac facility and New York State Electric and Gas in June 2009, and lower earnings at TransAlta Cogeneration, L.P. ("TA Cogen"). TransAlta continues to operate the facility in the merchant market.

13. COMMON SHARES ISSUED AND OUTSTANDING

A. Issued and outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. At Sept. 30, 2009, the Corporation had 197.9 million (Dec. 31, 2008 – 197.6 million) common shares issued and outstanding. During the three months ended Sept. 30, 2009, no shares (Sept. 30, 2008 – 0.1 million) were issued. During the nine months ended Sept. 30, 2009, 0.3 million shares (Sept. 30, 2008 – 0.6 million) were issued. In 2009, the shares issued were pursuant to the Corporation's Performance Share Ownership Plan ("PSOP") and therefore did not result in any cash proceeds. In 2008, the shares issued were pursuant to the Corporation's PSOP and stock options.

During both the three and nine months ended Sept. 30, 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program.

During the three and nine months ended Sept. 30, 2008, no shares, and 3.9 million shares, respectively, were acquired or cancelled under the NCIB program.

B. Stock options

At Sept. 30, 2009, the Corporation had 1.5 million outstanding employee stock options (Dec. 31, 2008 – 1.7 million). For the three months ended Sept. 30, 2009, no options were exercised, or cancelled, and no options expired. For the three months ended Sept. 30, 2008, no options were exercised, or cancelled, and no options expired.

For the nine months ended Sept. 30, 2009, no options were exercised, 0.1 million options with a weighted average exercise price of $29.77 per share were cancelled, and 0.1 million options expired. For the nine months ended Sept. 30, 2008, 0.3 million options with a weighted average exercise price of $20.54 per share were exercised resulting in 0.3 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $27.15 per share.

For the three and nine months ended Sept. 30, 2009, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was $0.3 million (Sept. 30, 2008 – $1 million) and $1.1 million (Sept. 30, 2008 – $3 million), respectively.

14. SHAREHOLDERS' EQUITY

Unaudited	Common shares	Retained earnings	Accumulated Other Comprehensive Income	Total shareholders' equity
Balance, Dec. 31, 2008	1,761	688	61	2,510
Net earnings	-	102	-	102
Common shares issued	6	-	-	6
Dividends declared	-	(172)	-	(172)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and tax	-	-	(55)	(55)
Gains on derivatives designated as cash flow hedges, net of tax	-	-	225	225
Derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net earnings in the current period	-	-	(103)	(103)
Balance, Sept. 30, 2009	**1,767**	**618**	**128**	**2,513**

The components of AOCI are presented below:

As at	Sept. 30, 2009	Dec. 31, 2008
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax	**(62)**	(7)
Cumulative unrealized gains on cash flow hedges, net of tax	**190**	68
Accumulated other comprehensive income	**128**	61

Normal Course Issuer Bid Program

On May 6, 2009, TransAlta announced plans to renew the NCIB program until May 6, 2010. The Corporation received the approval to purchase, for cancellation, up to 9.9 million of its common shares representing five per cent of the 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. No purchases were made under the NCIB program through Sept. 30, 2009.

Details of the share purchases under the Corporation's NCIB program are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Total shares purchased	-	-	**-**	3,886,400
Average purchase price per share	-	-	**-**	33.45
Total cost	-	-	**-**	130
Weighted average book value of shares cancelled	-	-	**-**	35
Reduction to retained earnings	-	-	**-**	95

15. CAPITAL

TransAlta's capital is comprised of the following components:

As at	**Sept. 30, 2009**	Dec. 31, 2008	(Decrease)/ increase
Current portion of long-term debt	**240**	244	(4)
Less: cash and cash equivalents	**(86)**	(50)	(36)
	154	194	(40)
Long-term debt			
Recourse	**2,666**	2,332	334
Non-recourse	**194**	232	(38)
Non-controlling interests	**484**	469	15
Shareholders' equity			
Common shares	**1,767**	1,761	6
Retained earnings	**618**	688	(70)
AOCI	**128**	61	67
	5,857	5,543	314
Total capital	**6,011**	5,737	274

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2008.

TransAlta monitors key credit ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and seeks to manage the Corporation's capital in line with the following targets:

	Sept. 30, 2009	Dec. 31, 2008	Target
Cash flow to interest (times) (1)	**5.8**	7.2	Minimum of 4
Cash flow to total debt (%) (1)	**23.6**	31.1	Minimum of 25
Debt to invested capital (%)	**50.1**	48.1	Maximum of 55

(1) Last 12 months.

For the three and nine months ended Sept. 30, 2009 and 2008, net cash outflows from operating activities, after dividends and capital asset additions, are summarized below:

	3 months ended Sept. 30			**9 months ended Sept. 30**		
	2009	2008	Increase/ (Decrease)	**2009**	2008	Increase/ (Decrease)
Cash flow from operating activities	**194**	202	(8)	**334**	610	(276)
Dividends paid	**(58)**	(58)	-	**(169)**	(163)	(6)
Capital asset expenditures	**(269)**	(306)	37	**(681)**	(695)	14
Net cash outflow	**(133)**	(162)	29	**(516)**	(248)	(268)

For the three months ended Sept. 30, 2009, the increase in the total net cash flows resulted primarily from higher cash earnings. For the nine months ended Sept. 30, 2009, the decrease in the total net cash flows resulted primarily from lower net earnings and less favourable working capital. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business.

The financial terms and conditions of the Corporation's credit facilities remain unchanged from Dec. 31, 2008.

On May 29, 2009, the Corporation issued debentures in the amount of $200 million which have financial terms and conditions similar to the other debentures of the Corporation. The financial terms and conditions of all other debentures remain unchanged from Dec. 31, 2008.

TransAlta's formal dividend policy has remained unchanged from Dec. 31, 2008.

16. RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership (“TAGP”), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership (“K3LP”), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Sept. 30, 2009, TAGP had received $48 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The total value of these contracts are U.S.$3 million per year for the years ending Dec. 31, 2009 and 2010.

For the period November 2002 to November 2012, one of TransAlta’s subsidiaries, TA Cogen, entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract and therefore has no risk other than counterparty risk.

17. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings which 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. Although there can be no assurance that any particular claim will be resolved in the Corporation’s favour, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware, when taken as a whole, will have a material adverse effect on the Corporation.

18. COMMITMENTS

TransAlta’s estimate of total costs for Keephills 3 has increased by $100 million due to a change in TransAlta’s original expectations of the labour required to complete the project. Commercial operations are expected to commence in the second quarter of 2011.

TransAlta’s estimate for the total cost of the Sundance Unit 5 uprate has increased by $5 million due to the reclassification of some costs out of planned maintenance to more accurately reflect the type of work being done.

On April 28, 2009, TransAlta announced plans to design, build, and operate Ardenville, a 69 megawatt (“MW”) wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the purchase was an operational 3 MW wind power project in Southern Alberta. As at Sept. 30, 2009, the total capital incurred on this project was $26 million. Commercial operations of the remainder of the facility are expected to commence in the first quarter of 2011.

On Jan. 29, 2009, TransAlta announced two efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded by 23 MW each, to a total of 450 MW, and are expected to be operational by the end of 2011 and 2012, respectively. The capital cost of the projects is estimated at $68 million. As at Sept. 30, 2009, the total capital incurred on these projects was $2 million.

19. PRIOR PERIOD REGULATORY DECISION

With respect to refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange and the California Independent System Operator, the California Parties have sought rehearing of the Federal Energy Regulatory Commission's ("FERC") refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. In a decision issued Aug. 24, 2007, which denied rehearing remanded matters to FERC, the Ninth Circuit ruled that FERC had properly excluded both the Summer Transactions and the CERS Transactions from the EL00-95 complaint proceeding. FERC has yet to respond to the remand.

20. GUARANTEES – LETTERS OF CREDIT

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Balance Sheets. The letters of credit do not contain recourse provisions nor does the Corporation hold any assets as collateral against the guarantees issued. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Sept. 30, 2009 totalled $296 million (Dec. 31, 2008 - $430 million) with no (Dec. 31, 2008 – nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.1 billion (Dec. 31, 2008 – $2.2 billion) of committed credit facilities of which $1.1 billion (Dec. 31, 2008 – $1.4 billion) is not drawn, and is available as of Sept. 30, 2009, subject to customary borrowing conditions.

21. SEGMENTED DISCLOSURES

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

3 months ended Sept. 30, 2009	**Generation**	**COD**	**Corporate**	**Total**
Revenues	**659**	**7**	**-**	**666**
Fuel and purchased power	**(286)**	**-**	**-**	**(286)**
	373	**7**	**-**	**380**
Operations, maintenance, and administration	**116**	**9**	**19**	**144**
Depreciation and amortization	**106**	**1**	**4**	**111**
Taxes, other than income taxes	**5**	**-**	**-**	**5**
Intersegment cost allocation	**8**	**(8)**	**-**	**-**
	235	**2**	**23**	**260**
	138	**5**	**(23)**	**120**
Foreign exchange gain				**1**
Net interest expense *(Note 9)*				**(36)**
Earnings before non-controlling interests and income taxes				**85**

3 months ended Sept. 30, 2008	Generation	COD	Corporate	Total
Revenues	770	21	-	791
Fuel and purchased power	(393)	-	-	(393)
	377	21	-	398
Operations, maintenance, and administration	129	17	15	161
Depreciation and amortization	102	1	5	108
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation	7	(7)	-	-
	243	11	20	274
	134	10	(20)	124
Foreign exchange loss				(4)
Net interest expense *(Note 9)*				(33)
Earnings before non-controlling interests and income taxes				87

9 months ended Sept. 30, 2009	**Generation**	**COD**	**Corporate**	**Total**
Revenues	**1,970**	**37**	**-**	**2,007**
Fuel and purchased power	**(900)**	**-**	**-**	**(900)**
	1,070	**37**	**-**	**1,107**
Operations, maintenance, and administration	**434**	**25**	**66**	**525**
Depreciation and amortization	**330**	**2**	**14**	**346**
Taxes, other than income taxes	**17**	**-**	**-**	**17**
Intersegment cost allocation	**24**	**(24)**	**-**	**-**
	805	**3**	**80**	**888**
	265	**34**	**(80)**	**219**
Foreign exchange gain				**4**
Net interest expense *(Note 9)*				**(102)**
Other income *(Note 11)*				**8**
Earnings before non-controlling interests and income taxes				**129**

9 months ended Sept. 30, 2008	Generation	COD	Corporate	Total
Revenues	2,221	81	-	2,302
Fuel and purchased power	(1,095)	-	-	(1,095)
	1,126	81	-	1,207
Operations, maintenance, and administration	368	37	69	474
Depreciation and amortization	298	2	12	312
Taxes, other than income taxes	15	-	-	15
Intersegment cost allocation	22	(22)	-	-
	703	17	81	801
	423	64	(81)	406
Foreign exchange loss				(5)
Net interest expense *(Note 9)*				(101)
Equity loss				(97)
Other income *(Note 11)*				5
Earnings before non-controlling interests and income taxes				208

B. Selected Consolidated Balance Sheet information

As at Sept. 30, 2009	Generation	COD	Corporate	Total
Goodwill	**103**	**30**	**-**	**133**
Total segment assets	**7,236**	**128**	**506**	**7,870**
As at Dec. 31, 2008				
Goodwill	112	30	-	142
Total segment assets	7,119	206	499	7,824

A change in foreign exchange rates has resulted in a $9 million decrease in goodwill in a self-sustaining foreign operation.

C. Selected Consolidated Cash Flow information

3 months ended Sept. 30, 2009	Generation	COD	Corporate	Total
Capital expenditures	**262**	**2**	**5**	**269**
3 months ended Sept. 30, 2008				
Capital expenditures	302	2	2	306

9 months ended Sept. 30, 2009	Generation	COD	Corporate	Total
Capital expenditures	**664**	**3**	**14**	**681**
9 months ended Sept. 30, 2008				
Capital expenditures	685	5	5	695

D. Depreciation and amortization on Consolidated Statements of Cash Flows

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2009	2008	**2009**	2008
Depreciation and amortization expense on Consolidated Statements of Earnings	**111**	108	**346**	312
Depreciation included in fuel and purchased power	**9**	1	**29**	16
Accretion expense included in depreciation and amortization expense	**(5)**	(5)	**(17)**	(16)
Other	**1**	1	**1**	4
Depreciation and amortization on Consolidated Statements of Cash Flows	**116**	105	**359**	316

22. EMPLOYEE FUTURE BENEFITS

Costs recognized in the period are presented below:

3 months ended Sept. 30, 2009	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**-**	**-**	**1**	**1**
Interest cost	**6**	**1**	**-**	**7**
Actual return on plan assets	**(4)**	**-**	**-**	**(4)**
Actuarial loss	**1**	**-**	**-**	**1**
Amortization of net transition asset	**(3)**	**-**	**-**	**(3)**
Defined benefit expense	**-**	**1**	**1**	**2**
Defined contribution option expense of registered pension plan	**4**	**-**	**-**	**4**
Net expense	**4**	**1**	**1**	**6**

3 months ended Sept. 30, 2008	Registered	Supplemental	Other	Total
Current service cost	1	-	-	1
Interest cost	5	1	-	6
Actual return on plan assets	(6)	-	-	(6)
Actuarial loss	-	1	-	1
Amortization of net transition asset	(2)	-	-	(2)
Defined benefit (income) expense	(2)	2	-	-
Defined contribution option expense of registered pension plan	4	-	-	4
Net expense	2	2	-	4

9 months ended Sept. 30, 2009	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**2**	**1**	**1**	**4**
Interest cost	**17**	**3**	**1**	**21**
Actual return on plan assets	**(14)**	**-**	**-**	**(14)**
Actuarial loss	**2**	**-**	**-**	**2**
Amortization of net transition asset	**(7)**	**-**	**-**	**(7)**
Defined benefit expense	**-**	**4**	**2**	**6**
Defined contribution option expense of registered pension plan	**14**	**-**	**-**	**14**
Net expense	**14**	**4**	**2**	**20**

9 months ended Sept. 30, 2008	Registered	Supplemental	Other	Total
Current service cost	3	1	1	5
Interest cost	15	2	1	18
Actual return on plan assets	(18)	-	-	(18)
Actuarial loss	1	1	-	2
Amortization of net transition asset	(7)	-	-	(7)
Defined benefit (income) expense	(6)	4	2	-
Defined contribution option expense of registered pension plan	13	-	-	13
Net expense	7	4	2	13

23. SUBSEQUENT EVENTS

TransAlta has evaluated subsequent events through to Oct. 26, 2009, which represents the date the financial statements were issued. TransAlta has not evaluated any subsequent events after that date.

Keephills 3

On Oct. 26, 2009, the Board of Directors approved an increase in the construction cost of Keephills 3 to $988 million due to a change in TransAlta's original expectations of the labour required to complete the project, and a change to the commencement of commercial operations from the first quarter of 2011 to the second quarter of 2011. The increase in construction cost is due to a change in TransAlta's original expectations of the labour required to complete the project. Even with the delay of operations and increased cost, Keephills 3 is still expected to meet TransAlta's investment hurdles.

Carbon Capture and Storage ("CCS")

On Oct. 14, 2009, the federal and provincial governments announced that TransAlta's CCS project, Project Pioneer, has received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a Front End Engineering and Design ("FEED") study to determine if the project is viable. The FEED study is expected to cost $20 million; $10 million will come from the federal government, $5 million will come from the provincial government, and $5 million will come from TransAlta and from industry partners Alstom Canada and Capital Power Corporation. The FEED study is expected to be complete in 2010 and if TransAlta proceeds with construction, the prototype plant has a targeted start-up date of 2015.

Offer to Acquire Canadian Hydro Developers, Inc. ("Canadian Hydro")

On Oct. 5, 2009, TransAlta entered into a definitive pre-acquisition agreement with Canadian Hydro to acquire all of their issued and outstanding common shares for $5.25 per share in cash. The transaction has a total value of approximately $1.7 billion, and has the unanimous support of the Board of Directors of both companies. The amended offer is subject to certain conditions, including acceptance of the amended offer by holders of at least 66⅔ per cent of Canadian Hydro's common shares calculated on a fully-diluted basis.

On Oct. 23, 2009, TransAlta completed the acquisition and payment for approximately 87 percent of the outstanding common shares of Canadian Hydro. TransAlta has extended its amended offer for common shares of Canadian Hydro to 3:00 p.m. (Calgary time) on Nov. 3, 2009 to allow additional time for Canadian Hydro shareholders to tender their shares.

Canadian Hydro operates 694 MW of wind, hydro and biomass facilities in Alberta, Ontario, Quebec, and British Columbia. Canadian Hydro's assets are highly contracted with counterparties of recognized standing. On a combined basis, TransAlta and Canadian Hydro will have 9,144 MW of gross generating capacity in operation (8,657 MW net ownership interest). The renewables portfolio will include 1,900 MW in operation, or 22 per cent of the combined portfolio. In addition, there would be 543 MW net under construction and over 500 MW in advanced-stage development.

The transaction will be initially funded with new committed credit facilities that are fully underwritten by a Canadian chartered bank, which, along with existing credit facilities and internally generated cash will provide ample funding to take up and pay for all of the outstanding Canadian Hydro shares. The transaction is not expected to impact TransAlta's dividend policy.

SUPPLEMENTAL INFORMATION

		Sept. 30, 2009	Dec. 31, 2008
Closing market price (TSX) ($)		**21.84**	24.30
Price range for the last 12 months (TSX) ($)	High	**29.83**	37.50
	Low	**18.11**	21.00
Debt to invested capital including non recourse debt (%)		**50.1**	48.1
Debt to invested capital excluding non recourse debt (%)		**48.2**	45.6
Return on shareholders' equity (%)		**8.2**	9.4
Comparable return on shareholders' equity[(1), (2)] (%)		**7.4**	11.6
Return on capital employed[(1)] (%)		**6.0**	7.7
Comparable return on capital employed[(1), (2)] (%)		**6.0**	9.6
Cash dividends per share[(1)] ($)		**1.14**	1.08
Price/earnings ratio[1] (times)		**22.1**	20.6
Earnings coverage[1] (times)		**2.1**	2.8
Dividend payout ratio based on net earnings[(1)] (%)		**115.3**	91.5
Dividend payout ratio based on comparable earnings[(1), (2)] (%)		**127.7**	74.1
Dividend coverage[(1)] (times)		**3.4**	4.8
Dividend yield[(1)] (%)		**5.2**	4.4
Cash flow to debt[(1)] (%)		**23.6**	31.1
Cash flow to interest coverage[(1)] (times)		**5.8**	7.2

(1) Last 12 months
(2) These ratios incorporate items that are not defined under Canadian GAAP. None of these measurements are used to enhance the Corporation's reported financial performance or position. 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.

RATIO FORMULAS

Debt to invested capital = (long-term debt – cash and cash equivalents) / (debt + non-controlling interests + shareholders' equity – cash and cash equivalents)

Return on shareholders' equity = net earnings or comparable earnings / average shareholders' equity excluding Accumulated Other Comprehensive Income ("AOCI")

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

Comparable return on capital employed = (comparable earnings before non-controlling interests and income taxes + net interest expense) / average invested capital excluding AOCI

Price/earnings ratio = current period's close / basic earnings per share

Earnings coverage = (net earnings + income taxes + net interest expense) / (net interest expense plus capitalized interest)

Dividend payout ratio = dividends / net earnings or comparable earnings

Dividend coverage = cash flow from operating activities / common share dividends

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

Cash flow to debt = cash flow from operating activities before changes in working capital / average total debt

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + net interest expense) / (net interest expense plus capitalized interest)

GLOSSARY OF KEY TERMS

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

Availability - A measure of 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 unit (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.

Carbon Capture and Storage (CCS) - An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

Cogeneration - A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

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

Gigawatt - A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh) - A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG) – Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

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

Megawatt (MW) - A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) - A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

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

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

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

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

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

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