**TRANSALTA CORPORATION**
**NEWS RELEASE**

**TransAlta announces fourth quarter and full year 2009 earnings; files year end disclosure documents**

- Fourth quarter comparable earnings per share[1] of $0.40; the same as last year
- Fourth quarter fleet availability of 87.0 per cent; an increase over fourth quarter 2008
- Full year 2009 comparable earnings per share of $0.90; cash flow from operations of $580 million
- Well positioned for 2010 due to progress on key initiatives in 2009
- Summerview 2 commissioned on budget and ahead of schedule

CALGARY, Alberta (Feb. 24, 2010) – TransAlta Corporation ("TransAlta") (TSX: TA; NYSE: TAC) today reported fourth quarter 2009 comparable earnings[1] of $84 million ($0.40 per share) versus $79 million ($0.40 per share) in 2008. Reported net earnings for the fourth quarter were $79 million ($0.37 per share) compared to $94 million ($0.47 per share) in 2008.

Comparable results for the quarter were primarily driven by lower planned and unplanned outages at the Alberta Thermal plants and lower unplanned outages at Genesee 3. These results were offset by lower hydro volumes and pricing in Alberta, and lower Energy Trading gross margins. Fourth quarter 2008 comparable earnings also benefited from an increase in interest income as a result of a favourable tax assessment. Net earnings in the quarter were lower due to the writedown of mining development costs at Centralia, Washington, and due to a $15 million tax recovery in 2008.

Cash flow from operations for the quarter was $246 million versus $428 million in the fourth quarter of 2008. Higher cash earnings in the quarter were offset by less favourable changes in working capital.

Fleet availability for the fourth quarter increased to 87.0 per cent compared to 86.2 per cent in the fourth quarter of 2008 due to lower planned and unplanned outages at Alberta Thermal and lower unplanned outages at Genesee 3, partially offset by higher unplanned outages at Centralia Thermal.

"We are confident in our ability to deliver better performance from our coal plants and achieve our fleet availability target in 2010," said Steve Snyder, TransAlta's President and CEO. "The major maintenance work we did in 2009 resulted in improved and more consistent performance from our Alberta Keephills and Sundance units. In addition to improving operating performance, we successfully implemented several other key initiatives in 2009 that will help drive the Company's success in the years ahead. These included the long-term recontracting of our Sarnia plant, the acquisition and successful integration of Canadian Hydro Developers, and securing government funding for Project Pioneer, one of the world's first and largest scale retrofit carbon capture and storage demonstration facilities," Snyder added.

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*(1) Comparable earnings and comparable earnings per share are not defined under Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). Presenting these measures from period to period helps management and shareholders evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section of the extended news release for further discussion of these items, including a reconciliation to net earnings.*

**Results for the 12 months ended December 31, 2009**

For the 12 months ended Dec. 31, 2009, comparable earnings were $181 million ($0.90 per share) compared to $290 million ($1.46 per share) for the 12 months ended Dec. 31, 2008. Net earnings were $181 million ($0.90 per share) compared to $235 million ($1.18 per share) in 2008. Earnings decreased in 2009 primarily due to higher planned and unplanned outages at Alberta Thermal, lower hydro volumes and pricing, and lower Energy Trading gross margins.

Cash flow from operations for the 12 months ended Dec. 31, 2009 was $580 million, compared to $1,038 million for the 12 months ended Dec. 31, 2008. The decrease in cash flow from operations in 2009 was driven by lower cash earnings and unfavourable movements in working capital compared to last year. In addition, in 2008 TransAlta received an additional Power Purchase Agreement ("PPA") payment of $116 million.

Fleet availability for the year was 85.1 per cent compared to 85.8 per cent in 2008. The decrease in availability is attributed to the higher planned and unplanned outages at Alberta Thermal and higher unplanned outages at Centralia Thermal, partially offset by lower planned outages at Centralia Thermal and lower planned and unplanned outages at Genesee 3.

**Subsequent Events**

**Summerview 2 Wind Farm begins commercial operation**

TransAlta announced today its 66 megawatt ("MW"), $123 million Summerview 2 Wind Farm began commercial operation on Feb. 23, 2010; on budget and ahead of schedule. The Summerview expansion is located adjacent to the original site and includes 22, three-MW, V90 Vestas wind turbines. The Summerview site now has a total installed capacity of 136 MW and will provide on average a total of 395,000 megawatt hours per year– enough electricity to meet the annual needs of approximately 55,000 homes, while offsetting 257,000 tonnes of $CO_2$.

TransAlta's renewable generation portfolio now totals 2,032 MW in operation and includes 950 MW of wind energy, 893 MW of hydroelectric, 164 MW of geothermal energy in California through a 50 per cent interest in CE Generation LLC and 25 MW of biomass. The Company also has another 123 MW of wind generation and 18 MW of Hydro under construction, which are scheduled to come on line in 2010 and 2011.

**TransAlta files year end disclosure documents**

TransAlta announced it will file today its Annual Information Form, Audited Consolidated Financial Statements and accompanying notes, as well as the Management's Discussion and Analysis ("MD&A"). These documents will be available through TransAlta's website at www.transalta.com or through Sedar at www.sedar.com.

TransAlta will also file today its 40-F with the U.S. Securities and Exchange Commission. The form will be available through their website at www.sec.gov/edgar.shtml. Paper copies of all documents are available to shareholders free of charge upon request.

A complete copy of TransAlta's fourth quarter extended news release is available on the Investors section of our website: www.transalta.com.

TransAlta will hold a conference call and web cast at 9 a.m. MT (11 a.m. ET) today to discuss results. The call will begin with a short address by Steve Snyder, President and CEO, and Brian Burden, Chief Financial Officer, followed by a question and answer period for investment analysts, investors, and other interested parties. A question and answer period for the media will immediately follow.

Please contact the conference operator five minutes prior to the call, noting "TransAlta Corporation" as the company and "Jennifer Pierce" as moderator.

Dial-in numbers:
For local Toronto participants – 1-416-340-8061
Toll-free North American participants – 1-866-225-0198

A link to the live webcast will be available via TransAlta's website, www.transalta.com, under Web Casts in the Investor Relations section. If you are unable to participate in the call, the instant replay is accessible at 1-800-408-3053 with TransAlta pass code 8782314. A transcript of the broadcast will be posted on TransAlta's website once it becomes available.
Note: If using a hands-free phone, lift the handset and press one to ask a question.

*TransAlta is a power generation and wholesale marketing company focused on creating long-term shareholder value. TransAlta maintains a low-to-moderate risk profile by operating a highly contracted portfolio of assets in Canada, the United States and Australia. TransAlta's focus is to efficiently operate our biomass, geothermal, wind, hydro, natural gas and coal facilities in order to provide our customers with a reliable, low-cost source of power. For 100 years, TransAlta has been a responsible operator and a proud contributor to the communities where we work and live. TransAlta is recognized for its leadership on sustainability by the Dow Jones Sustainability North America Index, the FTSE4Good Index and the Jantzi Social Index.*

*This news release may contain forward looking statements, including statements regarding the business and anticipated financial performance of TransAlta Corporation. These statements are based on TransAlta Corporation's belief and assumptions based on information available at the time the assumption was made. These statements are subject to a number of risks and uncertainties that may cause actual results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause such differences include legislative or regulatory developments, competition, global capital markets activity, changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta Corporation operates.*

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## 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 news release, 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 Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| Availability (%) | **87.0** | 86.2 | **85.1** | 85.8 |
| Production (GWh) | **12,297** | 12,656 | **45,736** | 48,891 |
| Revenue | **763** | 808 | **2,770** | 3,110 |
| Gross margin(1) | **435** | 410 | **1,542** | 1,617 |
| Operating income(1) | **159** | 127 | **378** | 533 |
| Net earnings | **79** | 94 | **181** | 235 |
| Net earnings per share, basic and diluted | **0.37** | 0.47 | **0.90** | 1.18 |
| Comparable earnings per share | **0.40** | 0.40 | **0.90** | 1.46 |
| Cash flow from operating activities | **246** | 428 | **580** | 1,038 |
| Free cash flow (deficiency)(1) | **78** | 154 | **(117)** | 121 |
| Cash dividends declared per share | **0.29** | 0.27 | **1.16** | 1.08 |

| | **As at Dec. 31, 2009** | As at Dec. 31, 2008 |
|---|---|---|
| Total assets | **9,762** | 7,824 |
| Total long-term financial liabilities | **5,512** | 3,645 |

## AVAILABILITY & PRODUCTION

Availability for the three months ended Dec. 31, 2009 increased compared to the same period in 2008 due to lower planned and unplanned outages at the Alberta Thermal plants ("Alberta Thermal"), and lower unplanned outages at the Genesse 3 Thermal plant ("Genesee 3"), partially offset by higher unplanned outages at the Centralia Thermal plant ("Centralia Thermal").

*(1) Gross margin, operating income, and free cash flow are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this news release for further discussion of these items, including a reconciliation to net earnings and cash flow from operating activities.*

Availability for the year ended Dec. 31, 2009 decreased due to higher planned and unplanned outages at Alberta Thermal, higher unplanned outages at Centralia Thermal, and higher planned outages at the Windsor and Mississauga plants, partially offset by lower planned outages at Centralia Thermal, and lower planned and unplanned outages at Genesee 3.

Production for the three months ended Dec. 31, 2009 decreased 359 gigawatt hours ("GWh") compared to the same period in 2008 due to higher unplanned outages at Centralia Thermal, the expiration of the long-term contract at Saranac, and lower PPA customer demand at Alberta Thermal and Sheerness, partially offset by higher wind volumes due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro") and the commissioning of Kent Hills, lower unplanned outages at Genesee 3, lower planned and unplanned outages at Alberta Thermal, and the completion of the uprate on Unit 5 of our Sundance facility.

Production for the year ended Dec. 31, 2009 decreased 3,155 GWh due to higher economic dispatching and higher unplanned outages at Centralia Thermal, higher planned and unplanned outages at Alberta Thermal, lower PPA customer demand at Alberta Thermal and Sheerness, the expiration of the long-term contract at Saranac, and lower hydro volumes, partially offset by higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, lower planned outages at Centralia Thermal, and lower planned and unplanned outages at Genesee 3.

## NET EARNINGS

The primary factors contributing to the change in net earnings for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 | Year ended Dec. 31 |
|---|---|---|
| Net earnings, 2008 | 94 | 235 |
| Increase (decrease) in Generation gross margins | 36 | (33) |
| Mark-to-market movements - Generation | 3 | 16 |
| Decrease in COD gross margins | (14) | (58) |
| Decrease (increase) in operations, maintenance, and administration cost | 21 | (30) |
| Increase in depreciation expense | (13) | (47) |
| Writedown of mining development costs | (16) | (16) |
| Increase in net interest expense | (33) | (34) |
| Decrease in equity loss | - | 97 |
| Decrease in non-controlling interest | 12 | 23 |
| (Increase) decrease in income tax expense | (21) | 8 |
| Other | 10 | 20 |
| **Net earnings, 2009** | **79** | **181** |

Generation gross margins, net of mark-to-market movements, increased for the three months ended Dec. 31, 2009 compared to the same period in 2008 as a result of higher wind volumes due to the acquisition of Canadian Hydro, lower planned and unplanned outages at Alberta Thermal, and lower unplanned outages at Genesee 3, partially offset by the expiration of the Saranac contract, lower hydro volumes, and unfavourable foreign exchange rates.

For the year ended Dec. 31, 2009, Generation gross margins, net of mark-to-market movements, decreased due to higher planned outages at Alberta Thermal, lower hydro volumes and prices, and the expiration of the long-term contract at Saranac, partially offset by lower planned and unplanned outages at Genesee 3, higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, favourable foreign exchange rates, and favourable contractual pricing.

For the three months ended Dec. 31, 2009, COD gross margins decreased relative to the same period in 2008 due to reduced opportunities in the eastern region resulting from smaller geographical pricing spreads.

For the year ended Dec. 31, 2009, COD gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

Operations, maintenance, and administration ("OM&A") costs for the three months ended Dec. 31, 2009 decreased compared to the same period in 2008 primarily due to lower planned outages, favourable foreign exchange rates, and lower compensation costs, partially offset by the acquisition of Canadian Hydro.

For the year ended Dec. 31, 2009, OM&A costs increased primarily due to higher planned outages and unfavourable foreign exchange rates, partially offset by targeted cost savings throughout the Corporation, and lower compensation costs.

Depreciation expense for the three months ended Dec. 31, 2009 increased compared to the same period in 2008 as a result of an increased asset base, partially offset by lower production at Saranac, which is depreciated on a unit of production basis.

For the year ended Dec. 31, 2009, depreciation expense increased due to an increased asset base, unfavourable foreign exchange rates, and the retirement of certain assets that were not fully depreciated during planned maintenance activities, partially offset by lower production at Saranac and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal in 2008.

In 2006, we ceased mining activities at the Centralia mine but continued to develop the option to mine the Westfield site, a coal reserve located adjacent to Centralia Thermal. With the successful modifications of the boilers at Centralia Thermal and longer-term contracts in place to supply coal, the project to develop the Westfields site has now been placed on hold indefinitely and the costs that have been capitalized were expensed during the fourth quarter of 2009.

Net interest expense increased for the three months ended Dec. 31, 2009 compared to the same period in 2008 due to higher long-term debt levels and the receipt of interest income from a tax settlement in 2008, partially offset by lower interest rates and favourable foreign exchange rates.

For the year ended Dec. 31, 2009, net interest expense increased due to higher long-term debt levels and lower interest income as a result of the receipt of interest income from a tax settlement in 2008, partially offset by lower interest rates and higher capitalized interest primarily due to the construction of Keephills 3.

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 months and year ended Dec. 31, 2009, non-controlling interest decreased compared to the same period in 2008 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 Dec. 31, 2009 compared to the same period in 2008 due to higher pre-tax earnings and the income tax recovery related to tax positions recorded in 2008, partially offset by the recovery recorded in 2009 for a change in future tax rates related to tax liabilities recorded in prior periods.

For the year ended Dec. 31, 2009, income tax expense decreased due to lower pre-tax earnings and the recovery recorded for a change in future tax rates related to tax liabilities recorded in prior periods, partially offset by the income tax recovery related to tax positions recorded in 2008.

## CASH FLOW

Cash flow from operating activities for the three months ended Dec. 31, 2009 decreased $182 million compared to the same period in 2008 due to less favourable changes in working capital, partially offset by higher cash earnings.

Cash flow from operating activities for the year ended Dec. 31, 2009 decreased $458 million due to lower cash earnings, the receipt of an additional PPA payment in 2008, higher inventory balances in 2009, and unfavourable movements in other working capital balances.

Free cash flow for the three months ended Dec. 31, 2009 decreased $76 million compared to the same period in 2008 primarily due to lower cash flow from operating activities, partially offset by lower sustaining capital expenditures.

For the year ended Dec. 31, 2009, free cash flow decreased $238 million due to lower cash flow from operating activities and the receipt of an additional PPA payment in 2008, partially offset by lower sustaining capital expenditures.

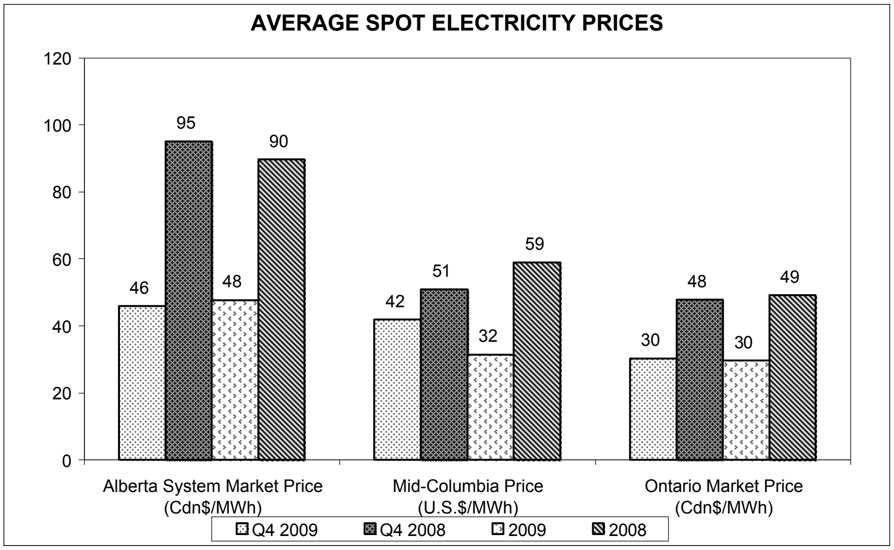
## BUSINESS ENVIRONMENT

*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 2009 Annual MD&A. The key characteristics of these markets are described below.*

### Electricity Prices

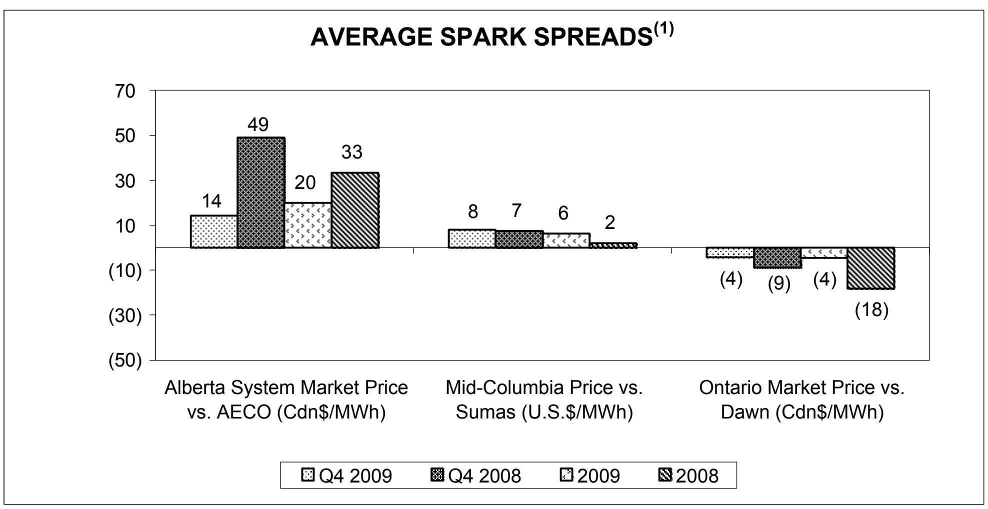
Please refer to the Business Environment section of the 2009 Annual MD&A for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the three months and year ended Dec. 31, 2009 and 2008 in our three major markets are shown in the following graphs.




For the three months and year ended Dec. 31, 2009, average spot prices decreased in Alberta, the Pacific Northwest, and in Ontario compared to the same periods in 2008 due to lower natural gas prices and weaker demand for electricity. In Alberta, prices also decreased due to increased availability across the province's thermal coal fleet.

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 in the 2010 Outlook section our 2009 Annual MD&A.




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

For the three months ended Dec. 31, 2009, average spark spreads decreased in Alberta compared to the same period in 2008 due to power prices decreasing more than natural gas prices as a result of increased availability across the province's thermal coal fleet. In the Pacific Northwest and Ontario, average spark spreads increased compared to the same period in 2008 due to power prices decreasing less than natural gas prices. In the Pacific Northwest, the increase was primarily due to colder winter weather in 2009 compared to 2008.

For the year ended Dec. 31, 2009, average spark spreads decreased in Alberta due to power prices decreasing more than natural gas prices as a result of increased availability across the province's thermal coal fleet. Spark spreads in the Pacific Northwest and Ontario increased as power prices have decreased less than natural gas prices. In the Pacific Northwest, the increase is primarily because 2009 had lower hydro-based electricity production than 2008.

During the fourth 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

TransAlta's operating results by segment are presented below:

| **3 months ended Dec. 31, 2009** | **Generation** | **COD** | **Corporate** | **Total** |
|---|---|---|---|---|
| **Revenues** | **753** | **10** | **-** | **763** |
| **Fuel and purchased power** | **(328)** | **-** | **-** | **(328)** |
| | **425** | **10** | **-** | **435** |
| **Operations, maintenance and administration** | **116** | **6** | **20** | **142** |
| **Depreciation and amortization** | **123** | **2** | **4** | **129** |
| **Taxes, other than income taxes** | **5** | **-** | **-** | **5** |
| **Intersegment cost allocation** | **8** | **(8)** | **-** | **-** |
| | **252** | **-** | **24** | **276** |
| | **173** | **10** | **(24)** | **159** |
| **Foreign exchange gain** | | | | **4** |
| **Writedown of mining development costs** | | | | **(16)** |
| **Net interest expense** | | | | **(42)** |
| **Earnings before non-controlling interests and income taxes** | | | | **105** |

| 3 months ended Dec. 31, 2008 | Generation | COD | Corporate | Total |
|---|---|---|---|---|
| Revenues | 784 | 24 | - | 808 |
| Fuel and purchased power | (398) | - | - | (398) |
| | 386 | 24 | - | 410 |
| Operations, maintenance and administration | 119 | 16 | 28 | 163 |
| Depreciation and amortization | 111 | 1 | 4 | 116 |
| Taxes, other than income taxes | 4 | - | - | 4 |
| Intersegment cost allocation | 8 | (8) | - | - |
| | 242 | 9 | 32 | 283 |
| | 144 | 15 | (32) | 127 |
| Foreign exchange loss | | | | (7) |
| Net interest expense | | | | (9) |
| Earnings before non-controlling interests and income taxes | | | | 111 |

| **Year ended Dec. 31, 2009** | **Generation** | **COD** | **Corporate** | **Total** |
|---|---|---|---|---|
| **Revenues** | **2,723** | **47** | **-** | **2,770** |
| **Fuel and purchased power** | **(1,228)** | **-** | **-** | **(1,228)** |
| | **1,495** | **47** | **-** | **1,542** |
| **Operations, maintenance and administration** | **550** | **31** | **86** | **667** |
| **Depreciation and amortization** | **453** | **4** | **18** | **475** |
| **Taxes, other than income taxes** | **22** | **-** | **-** | **22** |
| **Intersegment cost allocation** | **32** | **(32)** | **-** | **-** |
| | **1,057** | **3** | **104** | **1,164** |
| | **438** | **44** | **(104)** | **378** |
| **Foreign exchange gain** | | | | **8** |
| **Writedown of mining development costs** | | | | **(16)** |
| **Net interest expense** | | | | **(144)** |
| **Other income** | | | | **8** |
| **Earnings before non-controlling interests and income taxes** | | | | **234** |

| Year ended Dec. 31, 2008 | Generation | COD | Corporate | Total |
|---|---|---|---|---|
| Revenues | 3,005 | 105 | - | 3,110 |
| Fuel and purchased power | (1,493) | - | - | (1,493) |
| | 1,512 | 105 | - | 1,617 |
| Operations, maintenance and administration | 487 | 53 | 97 | 637 |
| Depreciation and amortization | 409 | 3 | 16 | 428 |
| Taxes, other than income taxes | 19 | - | - | 19 |
| Intersegment cost allocation | 30 | (30) | - | - |
| | 945 | 26 | 113 | 1,084 |
| | 567 | 79 | (113) | 533 |
| Foreign exchange loss | | | | (12) |
| Net interest expense | | | | (110) |
| Equity loss | | | | (97) |
| Other income | | | | 5 |
| Earnings before non-controlling interests and income taxes | | | | 319 |

**GENERATION:** *Owns and operates hydro, wind, geothermal, biomass, 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 2009 Annual MD&A). At Dec. 31, 2009, Generation had 9,199 MW of gross generating capacity[(1)] in operation (8,775 MW net ownership interest) and 424 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2009 Annual MD&A.*

The results of the Generation segment are as follows:

| | **2009** | | 2008 | |
|---|---|---|---|---|
| 3 months ended Dec. 31 | **Total** | **Per installed MWh[(1)]** | Total | Per installed MWh[(1)] |
| Revenues | **753** | **37.79** | 784 | 41.86 |
| Fuel and purchased power | **(328)** | **(16.46)** | (398) | (21.25) |
| Gross margin | **425** | **21.33** | 386 | 20.61 |
| Operations, maintenance and administration | **116** | **5.82** | 119 | 6.35 |
| Depreciation and amortization | **123** | **6.18** | 111 | 5.93 |
| Taxes, other than income taxes | **5** | **0.25** | 4 | 0.21 |
| Intersegment cost allocation | **8** | **0.40** | 8 | 0.43 |
| Operating expenses | **252** | **12.65** | 242 | 12.92 |
| Operating income | **173** | **8.68** | 144 | 7.69 |
| Installed capacity (GWh) | **19,928** | | 18,729 | |
| Production (GWh) | **12,297** | | 12,656 | |
| Availability (%) | **87.0** | | 86.2 | |

| | **2009** | | 2008 | |
|---|---|---|---|---|
| Year ended Dec. 31 | **Total** | **Per installed MWh[(1)]** | Total | Per installed MWh[(1)] |
| Revenues | **2,723** | **36.37** | 3,005 | 40.63 |
| Fuel and purchased power | **(1,228)** | **(16.40)** | (1,493) | (20.18) |
| Gross margin | **1,495** | **19.97** | 1,512 | 20.45 |
| Operations, maintenance and administration | **550** | **7.35** | 487 | 6.58 |
| Depreciation and amortization | **453** | **6.05** | 409 | 5.53 |
| Taxes, other than income taxes | **22** | **0.29** | 19 | 0.26 |
| Intersegment cost allocation | **32** | **0.43** | 30 | 0.41 |
| Operating expenses | **1,057** | **14.12** | 945 | 12.78 |
| Operating income | **438** | **5.85** | 567 | 7.67 |
| Installed capacity (GWh) | **74,866** | | 73,969 | |
| Production (GWh) | **45,736** | | 48,891 | |
| Availability (%) | **85.1** | | 85.8 | |

*(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 Dec. 31, 2009** | **Production (GWh)** | **Installed (GWh)** | **Revenue** | **Fuel & purchased power** | **Gross margin** | **Revenue per installed MWh** | **Fuel & purchased power per installed MWh** | **Gross margin per installed MWh** |
|---|---|---|---|---|---|---|---|---|
| **Western Canada** | **8,216** | **12,104** | **341** | **119** | **222** | **28.17** | **9.83** | **18.34** |
| **Eastern Canada** | **1,128** | **2,713** | **134** | **54** | **80** | **49.39** | **19.90** | **29.49** |
| **International** | **2,953** | **5,111** | **278** | **155** | **123** | **54.39** | **30.33** | **24.07** |
| | **12,297** | **19,928** | **753** | **328** | **425** | **37.79** | **16.46** | **21.33** |

| 3 months ended Dec. 31, 2008 | Production (GWh) | Installed (GWh) | Revenue | Fuel & purchased power | Gross margin | Revenue per installed MWh | Fuel & purchased power per installed MWh | Gross margin per installed MWh |
|---|---|---|---|---|---|---|---|---|
| Western Canada | 7,842 | 11,749 | 302 | 134 | 168 | 25.70 | 11.41 | 14.30 |
| Eastern Canada | 874 | 1,808 | 120 | 78 | 42 | 66.37 | 43.14 | 23.23 |
| International | 3,940 | 5,172 | 362 | 186 | 176 | 69.99 | 35.96 | 34.03 |
| | 12,656 | 18,729 | 784 | 398 | 386 | 41.86 | 21.25 | 20.61 |

| **Year ended Dec. 31, 2009** | **Production (GWh)** | **Installed (GWh)** | **Revenue** | **Fuel & purchased power** | **Gross margin** | **Revenue per installed MWh** | **Fuel & purchased power per installed MWh** | **Gross margin per installed MWh** |
|---|---|---|---|---|---|---|---|---|
| **Western Canada** | **30,443** | **46,334** | **1,182** | **435** | **747** | **25.51** | **9.39** | **16.12** |
| **Eastern Canada** | **3,829** | **8,256** | **428** | **225** | **203** | **51.84** | **27.25** | **24.59** |
| **International** | **11,464** | **20,276** | **1,113** | **568** | **545** | **54.89** | **28.01** | **26.88** |
| | **45,736** | **74,866** | **2,723** | **1,228** | **1,495** | **36.37** | **16.40** | **19.97** |

| Year ended Dec. 31, 2008 | Production (GWh) | Installed (GWh) | Revenue | Fuel & purchased power | Gross margin | Revenue per installed MWh | Fuel & purchased power per installed MWh | Gross margin per installed MWh |
|---|---|---|---|---|---|---|---|---|
| Western Canada | 32,364 | 46,096 | 1,314 | 525 | 789 | 28.51 | 11.39 | 17.12 |
| Eastern Canada | 3,290 | 7,194 | 501 | 351 | 150 | 69.64 | 48.79 | 20.85 |
| International | 13,237 | 20,679 | 1,190 | 617 | 573 | 57.55 | 29.84 | 27.71 |
| | 48,891 | 73,969 | 3,005 | 1,493 | 1,512 | 40.63 | 20.18 | 20.45 |

**Western Canada**

Our Western Canada assets consist of coal and natural gas-fired plants, hydro facilities, a biomass facility, and wind farms. Refer to the Discussion of Segmented Results section of our 2009 Annual MD&A for further details on our Western operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 (GWh) | Year ended Dec. 31 (GWh) |
|---|---|---|
| Production, 2008 | 7,842 | 32,364 |
| Lower (higher) planned outages at Alberta Thermal | 119 | (1,159) |
| Lower PPA customer demand | (281) | (817) |
| Lower hydro volumes | (3) | (351) |
| Lower (higher) unplanned outages at Alberta Thermal | 70 | (189) |
| Lower unplanned outages at Genesee 3 | 237 | 237 |
| No planned outage at Genesee 3 in 2009 | - | 145 |
| Higher wind volumes | 105 | 105 |
| Higher merchant volumes due to Sundance 5 uprate | 77 | 77 |
| Other | 50 | 31 |
| **Production, 2009** | **8,216** | **30,443** |

The primary factors contributing to the change in gross margin for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 | Year ended Dec. 31 |
|---|---|---|
| Gross margin, 2008 | 168 | 789 |
| Lower (higher) planned outages at Alberta Thermal | 14 | (85) |
| Lower hydro volumes and prices | (13) | (45) |
| Lower unplanned outages at Alberta Thermal | 15 | 4 |
| Lower (higher) coal costs | 4 | (4) |
| Lower penalties due to lower spot prices | 4 | 15 |
| Adjustment to prior period indices | - | 14 |
| Lower unplanned outages at Genesee 3 | 13 | 13 |
| No planned outage at Genesee 3 in 2009 | - | 12 |
| Higher wind volumes | 5 | 5 |
| Mark-to-market movements | 2 | 5 |
| Higher merchant volumes due to Sundance 5 uprate | 3 | 3 |
| Other | 7 | 21 |
| **Gross margin, 2009** | **222** | **747** |

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 natural gas-fired facilities, hydro facilities, and wind farms. Refer to the Discussion of Segmented Results section of our 2009 Annual MD&A for further details on our Eastern operations.

Production for the three months and year ended Dec. 31, 2009 increased 254 GWh and 539 GWh, respectively, primarily due to higher wind volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills.

For the three months and year ended Dec. 31, 2009, gross margin increased $38 million and $53 million, respectively, due to higher wind volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills, and the new agreement with the Ontario Power Authority ("OPA") at our Sarnia regional cogeneration power plant.

On Sept. 30, 2009, we entered into a new agreement with the 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.

**International**

Our International assets consist of coal and natural gas-fired facilities, hydro facilities, and geothermal assets in various locations in the United States and natural gas assets in Australia. Refer to the Discussion of Segmented Results section of our 2009 Annual MD&A for further details on our International operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 (GWh) | Year ended Dec. 31 (GWh) |
|---|---|---|
| Production, 2008 | 3,940 | 13,237 |
| Economic dispatching at Centralia Thermal | (114) | (1,445) |
| Expiration of Saranac contract | (316) | (515) |
| Higher unplanned outages at Centralia Thermal | (577) | (470) |
| Lower planned outages at Centralia Thermal | - | 613 |
| Higher production at Centralia Gas | 27 | 29 |
| Other | (7) | 15 |
| **Production, 2009** | **2,953** | **11,464** |

The primary factors contributing to the change in gross margin for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 | Year ended Dec. 31 |
|---|---|---|
| Gross margin, 2008 | 176 | 573 |
| Expiration of Saranac contract | (22) | (39) |
| Higher coal costs | (2) | (19) |
| Favourable commercial settlements in 2008 | - | (14) |
| Lower production at Centralia Thermal | (7) | (12) |
| (Unfavourable) favourable foreign exchange | (15) | 34 |
| (Unfavourable) favourable pricing | (6) | 24 |
| Mark-to-market movements | - | 11 |
| Other | (1) | (13) |
| **Gross margin, 2009** | **123** | **545** |

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 long-term contract 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 $6 million and $11 million decrease in depreciation expense from this lower level of production for the three months and year ended Dec. 31, 2009, respectively. 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 the expiration of this contract is approximately $8 million and $12 million for the three months and year ended Dec. 31, 2009, respectively.

**Operations, Maintenance and Administration Expense**

OM&A costs for the three months ended Dec. 31, 2009 are comparable to the same period in 2008 as a result of lower planned outages and favourable foreign exchange rates being largely offset by the acquisition of Canadian Hydro.

For the year ended Dec. 31, 2009, OM&A costs increased compared to the same period in 2008 primarily due to higher planned outages, unfavourable foreign exchange rates, and the acquisition of Canadian Hydro, partially offset by targeted cost savings.

**Depreciation Expense**

The primary factors contributing to the change in depreciation expense for the three months and year ended Dec. 31, 2009 are presented below:

| | 3 months ended Dec. 31 | Year ended Dec. 31 |
|---|---|---|
| Depreciation and amortization expense, 2008 | 111 | 409 |
| Increased asset base | 19 | 28 |
| (Favourable) unfavourable foreign exchange | (4) | 11 |
| Asset retirements | - | 9 |
| Expiration of Saranac long-term contract | (6) | (11) |
| Acceleration of depreciation at Centralia Thermal in 2008 | 1 | (10) |
| Other | 2 | 17 |
| **Depreciation and amortization expense, 2009** | **123** | **453** |

**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 the Discussion of Segmented Results section of our 2009 Annual MD&A.

The results of the COD segment are as follows:

| | 3 months ended Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| Gross margin | **10** | 24 | **47** | 105 |
| Operations, maintenance and administration | **6** | 16 | **31** | 53 |
| Depreciation and amortization | **2** | 1 | **4** | 3 |
| Intersegment cost allocation | **(8)** | (8) | **(32)** | (30) |
| Operating expenses | **-** | 9 | **3** | 26 |
| Operating income | **10** | 15 | **44** | 79 |

For the three months ended Dec. 31, 2009, COD gross margins decreased relative to the same period in 2008 due to reduced opportunities in the eastern region resulting from smaller geographical pricing spreads.

For the year ended Dec. 31, 2009, COD gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

OM&A costs for the three months and year ended Dec. 31, 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 for the three months ended Dec. 31, 2009 are comparable with 2008. The inter-segment cost allocations for the year ended Dec. 31, 2009 have increased slightly due to an increase in the work performed on behalf of the Generation segment.

## NET INTEREST EXPENSE

The components of interest expense are shown below:

| | 3 months ended Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| Interest on long-term debt | **51** | 48 | **183** | 177 |
| Interest income from tax settlement | **-** | (30) | **-** | (30) |
| Interest income | **-** | (1) | **(6)** | (16) |
| Capitalized interest | **(9)** | (8) | **(36)** | (21) |
| Other | **-** | - | **3** | - |
| Net interest expense | **42** | 9 | **144** | 110 |

The change in net interest expense for the three months and year ended Dec. 31, 2009, compared to the same period in 2008 is shown below:

| | 3 months ended Dec. 31 | Year ended Dec. 31 |
|---|---|---|
| Net interest expense, 2008 | 9 | 110 |
| Interest income from tax settlement in 2008 | 30 | 30 |
| Higher long-term debt levels | 20 | 28 |
| Lower interest income | 1 | 10 |
| Lower interest rates | (5) | (17) |
| Higher capitalized interest | (1) | (15) |
| Favourable foreign exchange | (12) | (5) |
| Other | - | 3 |
| **Net interest expense, 2009** | **42** | **144** |

## OTHER INCOME

During 2009, we settled an outstanding commercial issue that has been recorded as a pre-tax gain of $7 million in other income as this was related to our previously held Mexican equity investment. We also recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm.

During 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.

## NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three months and year ended Dec. 31, 2009 decreased $12 million and $23 million, respectively, due to lower earnings at CE Generation, LLC as a result of the expiration of the long-term contract at our Saranac facility, and lower earnings at TransAlta Cogeneration, L.P.

## INCOME TAXES

A reconciliation of income tax expense and effective tax rates is presented below:

| | 3 months ended Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| Earnings before income taxes | **94** | 88 | **196** | 258 |
| Equity loss | **-** | - | **-** | (97) |
| Other income | **-** | - | **7** | 5 |
| Earnings before income taxes, equity loss, and other income | **94** | 88 | **189** | 350 |
| Income tax expense (recovery) | **15** | (6) | **15** | 23 |
| Income tax recovery related to tax positions | **-** | 15 | **-** | 15 |
| Income tax recovery related to change in future tax rates | **5** | - | **5** | - |
| Income tax expense on other income | **-** | - | **(1)** | (1) |
| Income tax recovery recorded on the sale of our Mexican equity investment | **-** | 7 | **-** | 35 |
| Income tax expense excluding equity loss and other income | **20** | 16 | **19** | 72 |
| Effective tax rate on earnings before income taxes, equity loss, and other items (%) | **21** | 18 | **10** | 21 |

Income tax expense increased for the three months ended Dec. 31, 2009 compared to the same period in 2008 due to higher pre-tax earnings and the income tax recovery related to tax positions recorded in 2008, partially offset by the recovery recorded in 2009 for a change in future tax rates related to tax liabilities recorded in prior periods.

For the year ended Dec. 31, 2009, income tax expense decreased due to lower pre-tax earnings and the recovery recorded for a change in future tax rates related to tax liabilities recorded in prior periods, partially offset by the income tax recovery related to tax positions recorded in 2008.

The effective tax rate on earnings before income taxes, equity loss, and other items was comparable for the three months ended Dec. 31, 2009 and 2008. For the year ended Dec. 31, 2009, the effective tax rate on earnings before income taxes, equity loss, and other items decreased primarily due to a change in pre-tax earnings and certain deductions that do not fluctuate with earnings.

## STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the three months ended Dec. 31, 2009:

| 3 months ended Dec. 31 | **2009** | 2008 | Primary factors explaining change |
|---|---|---|---|
| Cash and cash equivalents, beginning of period | **86** | 66 | |
| Provided by (used in): | | | |
| Operating activities | **246** | 428 | Unfavourable changes in working capital of $199 million, partially offset by higher cash earnings of $17 million. |
| Investing activities | **(1,036)** | 45 | Acquisition of Canadian Hydro, net of cash acquired, for $766 million and sale of our Mexican equity investment in 2008 for $332 million, partially offset by a decrease in capital spending of $88 million. |
| Financing activities | **787** | (498) | Proceeds from issuance of long-term debt of $919 million, increase in draws on credit facilities of $670 million, and increase in proceeds from the issuance of common shares of $396 million, partially offset by a $708 million increase in the repayment of long-term debt. |
| Translation of foreign currency cash | **(1)** | 9 | |
| Cash and cash equivalents, end of period | **82** | 50 | |

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2009:

| Year ended Dec. 31 | **2009** | 2008 | Primary factors explaining change |
|---|---|---|---|
| Cash and cash equivalents, beginning of year | **50** | 51 | |
| Provided by (used in): | | | |
| Operating activities | **580** | 1,038 | Decrease in cash earnings of $99 million and unfavourable changes in working capital of $359 million. |
| Investing activities | **(1,598)** | (581) | Acquisition of Canadian Hydro, net of cash acquired, for $766 million and the sale of our Mexican equity investment in 2008 for $332 million, partially offset by a decrease in capital spending of $102 million and an increase in collateral received from counterparties of $87 million. |
| Financing activities | **1,053** | (467) | Increase in draws on credit facilities of $863 million, increase in proceeds from issuance of long-term debt of $617 million, increase in proceeds from issuance of common shares of $382 million, and the purchase of common shares under the NCIB program in 2008 of $130 million, partially offset by a $488 million increase in the repayment of long-term debt. |
| Translation of foreign currency cash | **(3)** | 9 | |
| Cash and cash equivalents, end of year | **82** | 50 | |

## 2010 OUTLOOK

***Business Environment***

**Power Prices**

In 2010, power prices are expected to remain at or slightly above 2009 levels due to the influence of low natural gas prices and minimal demand growth. In the Alberta market, the longer-term fundamentals of the market remain strong and the recovery of the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices is the main driver behind the recovery of power prices. Natural gas prices are expected to remain low until 2011.

**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 the timing and structure of its regulatory framework 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 Environmental Protection Agency. 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.

**Economic Environment**

While we do expect our results from operations in 2010 to be impacted by the current economic environment, we expect that this impact will be somewhat mitigated by the contracted production and prices through our PPAs and other long-term contracts.

A number of our financial and industrial counterparties have experienced credit rating downgrades and we expect 2010 will continue to be challenging for some of our counterparties. While we had no counterparty losses in 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.

***Operations***

**Capacity, Production, and Availability**

Generating capacity is expected to increase in 2010 due to the commissioning of Summerview 2 and Kent Hills 2. Overall production and availability for 2010 is expected to increase compared to 2009 due to lower planned and unplanned outages across the fleet, and the acquisition of Canadian Hydro. Overall fleet availability for 2010 is expected to be approximately 90 per cent.

**Commodity Hedging**

Through the Alberta PPAs and our other long-term contracts, approximately 75 per cent of our capacity is contracted over the next seven years. To provide further stability to future earnings, we enter into physical and financial contracts for periods of up to five years. As a result of the acquisition of Canadian Hydro, we also have various contracts with terms that extend beyond five 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. Approximately 89 per cent of our 2010 capacity is contracted with the average contracted price of $60-$65/MWh in Alberta and U.S.$50-$55/MWh in the Pacific Northwest.

**Fuel Costs**

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Coal costs for 2010, on a standard cost basis, are expected to increase five to 10 per cent compared to the prior year as a result of increased depreciation due to mine capital investment and higher diesel costs.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2010 is expected to be consistent with 2009.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America is expected to reduce the year to year volatility of prices going forward and may lead to greater opportunities to hedge our natural gas price exposure with longer term contracts.

In 2010, approximately 20 per cent of our fuel at our natural gas-fired facilities and seven per cent of our fuel at our coal-fired facilities is exposed to market fluctuations in energy commodity prices. We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

**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 for 2010 are expected to remain flat compared to 2009 as costs related to Canadian Hydro are expected to be offset by lower planned maintenance, our operational synergies, and productivity measures. OM&A costs per installed MWh for 2010 are expected to decrease primarily as a result of lower planned maintenance and an increase in installed capacity due to the acquisition of Canadian Hydro.

**Energy Trading**

Earnings from our COD segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading 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 by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign currency expenses, including interest charges, which largely offset our net foreign currency-denominated earnings.

**Net Interest Expense**

Net interest expense for 2010 is expected to be higher mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar 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 expect to maintain $2.1 billion of committed credit facilities, and will monitor our exposures and obligations to ensure we have sufficient liquidity to meet our requirements.

**Accounting Estimates**

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of our 2009 Annual MD&A, are based on the current economic environment and outlook. While we do not anticipate significant changes to these estimates as a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities. The unrealized gains or losses related to our risk management assets and liabilities are not expected to impact our cash flows as they are generally settled at the contracted prices.

***Capital Expenditures***

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

**Growth Capital Expenditures**

In 2009, we successfully completed two of our growth capital projects, Blue Trail and the Sundance Unit 5 uprate. We have nine significant growth capital projects that are currently in progress with targeted completion dates between Q4 2010 and Q4 2012.

A summary of each of these significant projects is outlined below:

| | Total Project | | 2009 | 2010 | | |
|---|---|---|---|---|---|---|
| Project | Estimated spend(1) | Incurred to date(1) | Actual spend(1) | Estimated spend(1) | Target completion date | Details |
| Keephills 3 | 988 | 707 | 231 | 225 - 245 | Q2 2011 | A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power |
| Blue Trail | 113 | 113 | 87 | - | Completed in Q4 2009 | A 66 MW wind farm in southern Alberta |
| Sundance Unit 5 uprate | 77 | 77 | 60 | - | Completed in Q4 2009 | A 53 MW efficiency uprate at our Sundance facility |
| Summerview 2 | 123 | 106 | 81 | 15 - 25 | Completed in Q1 2010 | A 66 MW expansion of our Summerview wind farm in southern Alberta |
| Keephills Unit 1 uprate | 34 | 1 | 1 | 5 - 10 | Q4 2011 | A 23 MW efficiency uprate at our Keephills facility |
| Keephills Unit 2 uprate | 34 | 1 | 1 | 0 - 5 | Q4 2012 | A 23 MW efficiency uprate at our Keephills facility |
| Ardenville | 135 | 27 | 27 | 95 - 105 | Q1 2011 | A 69 MW wind farm in southern Alberta |
| Bone Creek | 48 | 4 | 4 | 40 - 45 | Q1 2011 | An 18 MW hydro facility in British Columbia |
| Kent Hills 2 | 100 | 18 | 18 | 80 - 85 | Q4 2010 | A 54 MW expansion of our wind farm in New Brunswick |
| **Total growth** | **1,652** | **1,054** | **510** | **460 - 520** | | |

Prior to our acquisition of Canadian Hydro, $23 million of costs were incurred in respect of Bone Creek, which do not form part of our total project cost.

*(1) Amounts are shown net of joint venture contributions.*

### Sustaining Capital Expenditures

For 2010, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

| Category | Description | Incurred in 2009 | Expected cost |
|---|---|---|---|
| Routine capital | Expenditures to maintain our existing generating capacity | 158 | 120 - 140 |
| Productivity capital | Projects to improve power production efficiency | 44 | 10 - 15 |
| Mining equipment and land purchases | Expenditures related to mining equipment and land purchases | 42 | 25 - 30 |
| Centralia modifications | Capital project to convert to external coal | 21 | - |
| Planned maintenance | Regularly scheduled major maintenance | 115 | 140 - 155 |
| **Total sustaining expenditures** | | **380** | **295 - 340** |

Details of the 2010 planned maintenance program are outlined as follows:

| | Coal | Gas | Renewables | Expected cost |
|---|---|---|---|---|
| Capitalized | 70 - 75 | 45 - 50 | 25 - 30 | **140 - 155** |
| Expensed | 60 - 65 | 0 - 5 | - | **60 - 70** |
| | 130 - 140 | 45 - 55 | 25 - 30 | **200 - 225** |

| | Coal | Gas | Renewables | Total |
|---|---|---|---|---|
| GWh lost | 1,770 - 1,780 | 360 - 370 | - | **2,130 - 2,150** |

### Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, and capital markets. 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 flow, our solid financial position, and the amount of capital available to us under existing committed credit facilities.

## 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 Canadian GAAP, and therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings or cash flow from operating activities, as determined in accordance with Canadian GAAP, when assessing 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 Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| **Revenues** | **763** | 808 | **2,770** | 3,110 |
| Fuel and purchased power | **(328)** | (398) | **(1,228)** | (1,493) |
| **Gross margin** | **435** | 410 | **1,542** | 1,617 |
| Operations, maintenance, and administration | **142** | 163 | **667** | 637 |
| Depreciation and amortization | **129** | 116 | **475** | 428 |
| Taxes, other than income taxes | **5** | 4 | **22** | 19 |
| **Operating expenses** | **276** | 283 | **1,164** | 1,084 |
| **Operating income** | **159** | 127 | **378** | 533 |
| Foreign exchange gain (loss) | **4** | (7) | **8** | (12) |
| Writedown of mining development costs | **(16)** | - | **(16)** | - |
| Net interest expense | **(42)** | (9) | **(144)** | (110) |
| Equity loss | **-** | **-** | **-** | (97) |
| Other income | **-** | **-** | **8** | 5 |
| **Earnings before non-controlling interests and income taxes** | **105** | 111 | **234** | 319 |
| Non-controlling interests | **11** | 23 | **38** | 61 |
| **Earnings before income taxes** | **94** | 88 | **196** | 258 |
| Income tax expense (recovery) | **15** | (6) | **15** | 23 |
| **Net earnings** | **79** | 94 | **181** | 235 |

### 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 calculated using the weighted average common shares outstanding during the period.

In calculating comparable earnings for 2009, we have excluded the writedown of mining development costs, the impact of a future tax rate change, and the settlement of an outstanding commercial issue that has been recorded in other income as this was related to our previously held Mexican equity 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 of Centralia to consuming solely third party supplied coal.

In calculating comparable earnings for 2008, we have also excluded the writedown of our Mexican equity investment and a recovery related to certain tax positions. 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 Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| **Net earnings** | **79** | 94 | **181** | 235 |
| Gain on sale of assets at Centralia, net of tax | **-** | - | **-** | (4) |
| Change in life of Centralia parts, net of tax | **-** | 3 | **1** | 12 |
| Writedown of mining development costs, net of tax | **10** | - | **10** | - |
| Settlement of commercial issue, net of tax | **-** | - | **(6)** | - |
| Tax rate change | **(5)** | - | **(5)** | - |
| Recovery related to tax positions | **-** | (15) | **-** | (15) |
| Writedown of Mexican equity investment, net of tax | **-** | (3) | **-** | 62 |
| **Earnings on a comparable basis** | **84** | 79 | **181** | 290 |
| Weighted average common shares outstanding in the period | **211** | 198 | **201** | 199 |
| **Earnings on a comparable basis per share** | **0.40** | 0.40 | **0.90** | 1.46 |

**Free Cash Flow (Deficiency)**

Free cash flow represents the amount of cash generated by our business that is available to invest in growth initiatives, repay scheduled principal repayments of recourse debt, pay additional common share dividends, or repurchase common shares.

Sustaining capital expenditures for the three months ended Dec. 31, 2009, represents total additions to property, plant, and equipment per the Consolidated Statements of Cash Flows less $136 million ($132 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2008, we invested $140 million ($114 million net of joint venture contributions) in growth projects. For the year ended Dec. 31, 2009 and 2008, we invested $524 million ($510 million net of joint venture contributions) and $541 million ($515 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 Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| | **2009** | 2008 | **2009** | 2008 |
| **Cash flow from operating activities** | **246** | 428 | **580** | 1,038 |
| Add (Deduct): | | | | |
| Sustaining capital expenditures | **(87)** | (171) | **(380)** | (465) |
| Dividends paid on common shares | **(57)** | (49) | **(226)** | (212) |
| Distributions paid to subsidiaries' non-controlling interests | **(18)** | (29) | **(58)** | (98) |
| Non-recourse debt repayments(1) | **(6)** | (25) | **(25)** | (28) |
| Timing of contractually scheduled PPA payments | **-** | - | **-** | (116) |
| Other income | **-** | - | **(8)** | - |
| Cash flows from equity investments | **-** | - | **-** | 2 |
| **Free cash flow (deficiency)** | **78** | 154 | **(117)** | 121 |

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

*(1) Excludes debt repayments related to recourse debt that have been or will be refinanced with long-term debt issuances, consistent with our overall capital strategy.*

**Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA")**

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

| | 3 months ended Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| **Year ended Dec. 31** | **2009** | 2008 | **2009** | 2008 |
| Operating income | **159** | 127 | **378** | 533 |
| Accretion | **7** | 6 | **24** | 22 |
| Depreciation and amortization per the cash flow statement[1] | **134** | 135 | **493** | 451 |
| EBITDA | **300** | 268 | **895** | 1,006 |

## SELECTED QUARTERLY INFORMATION

| | Q1 2009 | Q2 2009 | Q3 2009 | **Q4 2009** |
|---|---|---|---|---|
| Revenue | 756 | 585 | 666 | **763** |
| Net earnings (loss) | 42 | (6) | 66 | **79** |
| Basic and diluted earnings (loss) per common share | 0.21 | (0.03) | 0.34 | **0.37** |
| Comparable earnings (loss) per common share | 0.18 | (0.03) | 0.34 | **0.40** |

| | Q1 2008 | Q2 2008 | Q3 2008 | Q4 2008 |
|---|---|---|---|---|
| Revenue | 803 | 708 | 791 | 808 |
| Net earnings | 33 | 47 | 61 | 94 |
| Basic and diluted earnings per common share | 0.17 | 0.24 | 0.31 | 0.47 |
| Comparable earnings per common share | 0.50 | 0.25 | 0.32 | 0.40 |

Basic and diluted earnings (loss) per common share and comparable earnings (loss) per common share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per common share for the four quarters making up the calendar year may sometimes differ from the annual earnings per common share.

## FORWARD LOOKING STATEMENTS

This earnings release, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward looking statements. All forward looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from those projected.

*(1) To calculate EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in cost of sales per the Consolidated Statements of Earnings and Retained Earnings.*

In particular, this earnings release contains forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and upgrades, and their attendant costs; expectations related to future earnings and cash flow from operating activities; expectations relating to the timing of the completion of the FEED study regarding CCS and the cost of the study; estimates of fuel supply and demand conditions and the costs of procuring fuel; our plans to invest in existing and new capacity, and the expected return on those investments; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; our plans to install mercury control equipment at our Alberta Thermal operations and our initiative to reduce nitrogen oxide and mercury emissions from our Centralia Plant; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; expectations relating to the renegotiation of certain of the collective bargaining agreements to which we are a party; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; expectations for the outcome of existing or potential legal claims; and expectations for the ability to access capital markets at reasonable terms.

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) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) our provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2009 Annual MD&A and under the heading “Risk Factors” in our 2009 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward looking statements and are cautioned not to place undue reliance on these forward looking statements. The forward looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward looking events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure 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 Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| Unaudited | **2009** | 2008 | **2009** | 2008 |
| **Revenues** | **763** | 808 | **2,770** | 3,110 |
| Fuel and purchased power | **(328)** | (398) | **(1,228)** | (1,493) |
| | **435** | 410 | **1,542** | 1,617 |
| Operations, maintenance, and administration | **142** | 163 | **667** | 637 |
| Depreciation and amortization | **129** | 116 | **475** | 428 |
| Taxes, other than income taxes | **5** | 4 | **22** | 19 |
| | **276** | 283 | **1,164** | 1,084 |
| | **159** | 127 | **378** | 533 |
| Foreign exchange gain (loss) | **4** | (7) | **8** | (12) |
| Writedown of mining development costs | **(16)** | - | **(16)** | - |
| Net interest expense | **(42)** | (9) | **(144)** | (110) |
| Equity loss | **-** | - | **-** | (97) |
| Other income | **-** | - | **8** | 5 |
| **Earnings before non-controlling interests and income taxes** | **105** | 111 | **234** | 319 |
| Non-controlling interests | **11** | 23 | **38** | 61 |
| **Earnings before income taxes** | **94** | 88 | **196** | 258 |
| Income tax expense (recovery) | **15** | (6) | **15** | 23 |
| **Net earnings** | **79** | 94 | **181** | 235 |
| **Retained earnings** | | | | |
| **Opening balance** | **618** | 648 | **688** | 763 |
| Common share dividends | **(63)** | (54) | **(235)** | (215) |
| Shares cancelled under NCIB | **-** | - | **-** | (95) |
| **Closing balance** | **634** | 688 | **634** | 688 |
| **Weighted average number of common shares outstanding in the period** | **211** | 198 | **201** | 199 |
| **Net earnings per share, basic and diluted** | **0.37** | 0.47 | **0.90** | 1.18 |

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

| Unaudited | Dec. 31, 2009 | Dec. 31, 2008[1] |
|---|---|---|
| Cash and cash equivalents | **82** | 50 |
| Accounts receivable | **421** | 505 |
| Collateral paid | **27** | 37 |
| Prepaid expenses | **18** | 6 |
| Risk management assets | **144** | 200 |
| Future income tax assets | **17** | 3 |
| Income taxes receivable | **39** | 61 |
| Inventory | **90** | 51 |
| | **838** | 913 |
| **Long-term receivable** | **49** | 14 |
| **Property, plant, and equipment** | | |
| Cost | **11,721** | 9,932 |
| Accumulated depreciation | **(4,143)** | (3,898) |
| | **7,578** | 6,034 |
| **Goodwill** | **434** | 142 |
| **Intangible assets** | **333** | 213 |
| **Future income tax assets** | **204** | 248 |
| **Risk management assets** | **224** | 221 |
| **Other assets** | **102** | 39 |
| **Total assets** | **9,762** | 7,824 |
| Accounts payable and accrued liabilities | **521** | 658 |
| Collateral received | **86** | 24 |
| Risk management liabilities | **45** | 148 |
| Income taxes payable | **10** | 15 |
| Future income tax liabilities | **57** | 14 |
| Dividends payable | **61** | 52 |
| Current portion of long-term debt - recourse | **7** | 211 |
| Current portion of long-term debt - non-recourse | **24** | 33 |
| Current portion of asset retirement obligation | **32** | 45 |
| | **843** | 1,200 |
| **Long-term debt - recourse** | **3,857** | 2,332 |
| **Long-term debt - non-recourse** | **554** | 232 |
| **Asset retirement obligation** | **250** | 252 |
| **Deferred credits and other long-term liabilities** | **136** | 131 |
| **Future income tax liabilities** | **637** | 596 |
| **Risk management liabilities** | **78** | 102 |
| **Non-controlling interests** | **478** | 469 |
| **Common shareholders' equity** | | |
| Common shares | **2,169** | 1,761 |
| Retained earnings | **634** | 688 |
| Accumulated other comprehensive income | **126** | 61 |
| **Total shareholders' equity** | **2,929** | 2,510 |
| **Total liabilities and shareholders' equity** | **9,762** | 7,824 |

[1] *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.*

**TRANSALTA CORPORATION**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
*(in millions of Canadian dollars)*

| Unaudited | 3 months ended Dec. 31 **2009** | 2008 | Year ended Dec. 31 **2009** | 2008 |
|---|---|---|---|---|
| **Net earnings** | **79** | 94 | **181** | 235 |
| **Other comprehensive income (loss)** | | | | |
| (Losses) gains on translating net assets of self-sustaining foreign operations | **(51)** | 253 | **(209)** | 342 |
| Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1) | **37** | (203) | **140** | (295) |
| Gains on derivatives designated as cash flow hedges, net of tax(2) | **55** | 145 | **280** | 198 |
| Loss on sale of Mexico equity investment reclassified to the Consolidated Statements of Earnings, net of tax(3) | **-** | (8) | **-** | (8) |
| Reclassification of derivatives designated as cash flow hedges to Consolidated Balance Sheets, net of tax(4) | **(3)** | - | **(11)** | 8 |
| Reclassification of derivatives designated as cash flow hedges to net earnings, net of tax(5) | **(40)** | 4 | **(135)** | 61 |
| **Other comprehensive (loss) income** | **(2)** | 191 | **65** | 306 |
| **Comprehensive income** | **77** | 285 | **246** | 541 |

*(1) Net of income tax expense of 5 million and 26 million for the three months and year ended Dec. 31, 2009 (2008 - 48 million recovery and 61 million recovery), respectively.*

*(2) Net of income tax expense of 24 million and 120 million for the three months and year ended Dec. 31, 2009 (2008 - 86 million expense and 129 million expense), respectively.*

*(3) Net of income tax expense of 9 million and nil for the three months and year ended Dec. 31, 2008.*

*(4) Net of income tax recovery of 1 million and 4 million for the three months and year ended Dec. 31, 2009 (2008 - nil), respectively.*

*(5) Net of income tax recovery of 17 million and 69 million for the three months and year ended Dec. 31, 2009 (2008 - 2 million expense and 30 million expense), respectively.*

**TRANSALTA CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

*(in millions of Canadian dollars)*

| | 3 months ended Dec. 31 | | Year ended Dec. 31 | |
|---|---|---|---|---|
| Unaudited | **2009** | 2008 | **2009** | 2008 |
| **Operating activities** | | | | |
| Net earnings | **79** | 94 | **181** | 235 |
| Depreciation and amortization | **134** | 135 | **493** | 451 |
| Gain on sale of equipment | **-** | - | **-** | (5) |
| Non-controlling interests | **11** | 23 | **38** | 61 |
| Asset retirement obligation accretion | **7** | 6 | **24** | 22 |
| Asset retirement costs settled | **(8)** | (11) | **(35)** | (37) |
| Future income taxes | **21** | 13 | **21** | 1 |
| Unrealized loss from risk management activities | **3** | 1 | **2** | 12 |
| Unrealized foreign exchange loss (gain) | **4** | (10) | **(11)** | (5) |
| Writedown of mining development costs | **16** | - | **16** | - |
| Equity loss | **-** | - | **-** | 97 |
| Other non-cash items | **(1)** | (2) | **-** | (4) |
| | **266** | 249 | **729** | 828 |
| Change in non-cash operating working capital balances | **(20)** | 179 | **(149)** | 210 |
| Cash flow from operating activities | **246** | 428 | **580** | 1,038 |
| **Investing activities** | | | | |
| Acquisition of Canadian Hydro Developers, Inc., net of cash acquired | **(766)** | - | **(766)** | - |
| Additions to property, plant, and equipment | **(223)** | (311) | **(904)** | (1,006) |
| Proceeds on sale of property, plant, and equipment | **2** | 4 | **7** | 30 |
| Proceeds on sale of minority interest in Kent Hills | **-** | - | **29** | - |
| Restricted cash | **1** | 1 | **-** | 248 |
| Income tax receivable | **(41)** | - | **(41)** | (8) |
| Realized gains (losses) on financial instruments | **-** | 15 | **(16)** | 52 |
| Loan to equity investment | **-** | - | **-** | (245) |
| Proceeds on sale of equity investment | **-** | 332 | **-** | 332 |
| Net (decrease) increase in collateral received from counterparties | **(18)** | - | **87** | - |
| Net (increase) decrease in collateral paid to counterparties | **(2)** | - | **7** | - |
| Settlement of adjustments on sale of Mexican equity investment | **-** | - | **(7)** | - |
| Other | **11** | 4 | **6** | 16 |
| Cash flow (used in) from investing activities | **(1,036)** | 45 | **(1,598)** | (581) |
| **Financing activities** | | | | |
| Net increase (decrease) in credit facilities | **320** | (350) | **620** | (243) |
| Repayment of long-term debt | **(776)** | (68) | **(796)** | (308) |
| Issuance of long-term debt | **919** | - | **1,119** | 502 |
| Dividends paid on common shares | **(57)** | (49) | **(226)** | (212) |
| Funds paid to repurchase common shares under NCIB | **-** | - | **-** | (130) |
| Net proceeds on issuance of common shares | **398** | 1 | **398** | 15 |
| Realized gains on financial instruments | **-** | - | **-** | 12 |
| Distributions paid to subsidiaries' non-controlling interests | **(18)** | (29) | **(58)** | (98) |
| Other | **1** | (3) | **(4)** | (5) |
| Cash flow from (used in) financing activities | **787** | (498) | **1,053** | (467) |
| **Cash flow from (used in) operating, investing, and financing activities** | **(3)** | (25) | **35** | (10) |
| **Effect of translation on foreign currency cash** | **(1)** | 9 | **(3)** | 9 |
| **Increase (decrease) in cash and cash equivalents** | **(4)** | (16) | **32** | (1) |
| **Cash and cash equivalents, beginning of year** | **86** | 66 | **50** | 51 |
| **Cash and cash equivalents, end of year** | **82** | 50 | **82** | 50 |
| Cash taxes paid | **8** | (5) | **43** | 47 |
| Cash interest paid | **71** | 31 | **149** | 106 |

## SUPPLEMENTAL INFORMATION

| | | Dec. 31, 2009 | Dec. 31, 2008 |
|---|---|---|---|
| Closing market price (TSX) ($) | | **23.48** | 24.30 |
| Price range for the last 12 months (TSX) ($) | High | **25.30** | 37.50 |
| | Low | **18.11** | 21.00 |
| Debt to invested capital including non recourse debt (%) | | **56.1** | 48.1 |
| Debt to invested capital excluding non recourse debt (%) | | **52.6** | 45.6 |
| Return on shareholders' equity (%) | | **6.9** | 9.4 |
| Comparable return on shareholders' equity[1], [2] (%) | | **6.9** | 11.6 |
| Return on capital employed[1] (%) | | **5.7** | 7.7 |
| Comparable return on capital employed[1], [2] (%) | | **5.8** | 9.6 |
| Cash dividends per share[1] ($) | | **1.16** | 1.08 |
| Price/earnings ratio[1] (times) | | **26.1** | 20.6 |
| Earnings coverage[1] (times) | | **1.9** | 2.8 |
| Dividend payout ratio based on net earnings[1] (%) | | **129.8** | 91.5 |
| Dividend payout ratio based on comparable earnings[1], [2] (%) | | **129.8** | 74.1 |
| Dividend coverage[1] (times) | | **2.5** | 4.8 |
| Dividend yield[1] (%) | | **4.9** | 4.4 |
| Cash flow to debt[1] (%) | | **20.1** | 31.1 |
| Cash flow to interest coverage[1] (times) | | **4.9** | 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** = (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 or comparable earnings before non-controlling interests and income taxes + net interest expense) / average invested capital excluding AOCI

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

**Earnings coverage** = (net earnings + income taxes + net interest expense) / (interest on long-term debt – interest income)

**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) / (interest on long-term debt – interest income)

## 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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