TRANSALTA CORPORATION

THIRD QUARTER REPORT FOR 2007

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 31 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 three and nine months ended Sept. 30, 2007 and 2006, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in our annual report for the year ended Dec. 31, 2006. 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. 23, 2007. 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 Corporate Development and Marketing ("CD&M"). Our segments are supported by a corporate group that provides finance, treasury, legal, regulatory, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, 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 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	
	2007	2006	**2007**	2006
Availability (%)	**85.1**	84.1	**85.6**	88.6
Production (GWh)	**12,761**	12,420	**36,955**	34,915
Revenue	**$ 711.6**	$ 656.0	**$ 1,991.8**	$ 1,925.6
Gross margin[1]	**$ 375.5**	$ 353.9	**$ 1,109.1**	$ 1,087.0
Operating income [1]	**$ 128.8**	$ 98.2	**$ 357.6**	$ 327.9
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9
Basic and diluted earnings per common share	**$ 0.33**	$ 0.18	**$ 0.88**	$ 0.95
Cash flow from operating activities	**$ 155.3**	$ 144.8	**$ 654.7**	$ 411.9
Cash dividends declared per share	**$ 0.25**	$ 0.25	**$ 0.25**	$ 1.00

	Sept. 30, 2007	Dec. 31, 2006
Total assets	**$ 7,214.0**	$ 7,460.1
Total long-term financial liabilities	**$ 3,022.8**	$ 3,094.1

1 Gross margin and Operating income are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 29 of this MD&A for a further discussion of these items, including a reconciliation to net earnings.

AVAILABILITY & PRODUCTION

Availability for the three months ended Sept. 30, 2007 increased to 85.1 per cent from 84.1 per cent compared to the same period in 2006 due to lower unplanned outages at the Centralia Coal-fired plant ("Centralia Coal") partially offset by higher unplanned outages at the Alberta Thermal plants ("Alberta Thermal") and at the Centralia Gas-fired plant ("Centralia Gas").

Availability for the nine months ended Sept. 30, 2007 decreased to 85.6 per cent from 88.6 per cent compared to the same period in 2006 primarily as a result of derating at Centralia Coal due to test burning Powder River Basin ("PRB") coal in the first and second quarters of 2007 and higher unplanned outages at Alberta Thermal.

Production for the third quarter increased 341 gigawatt hours ("GWh") compared to the same period in 2006 as a result of lower unplanned outages at Centralia Coal and increased hydro production partially offset by higher planned and unplanned outages at Alberta Thermal and from lower production at Centralia Gas.

Production for the first nine months of 2007 increased 2,040 GWh compared to the same period in 2006 primarily due to increased production at Centralia Coal, higher hydro production, and increased customer and market demand at various gas facilities partially offset by higher planned and unplanned outages at Alberta Thermal and lower production at Centralia Gas.

NET EARNINGS

For the three months ended Sept. 30, 2007, reported net earnings increased to $65.9 million from $35.3 million and for the nine months ended Sept. 30, 2007, decreased to $179.3 million from $190.9 million compared to the same periods in 2006. For the three months ended Sept. 30, 2007, comparable earnings[1] were $63.6 million ($0.32 per common share) compared to $35.3 million ($0.18 per common share) in the same period in 2006. Comparable earnings for the nine months ended Sept. 30, 2007 were $161.7 million ($0.80 per common share), compared to $141.8 million ($0.71 per common share) over the same period in 2006.

A reconciliation of net earnings is presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net earnings, 2006	$ 35.3	$ 190.9
Increase in Generation gross margins (before mark-to-market gains and losses)	19.5	68.0
Generation mark-to-market gains (losses)	7.1	(32.9)
Decrease in CD&M margins	(5.0)	(13.0)
Decrease / (Increase) in operations, maintenance and administration costs	4.7	(1.4)
Decrease in depreciation expense	4.1	8.5
Gain on sale of Centralia mining equipment	3.4	15.1
Decrease in net interest expense	19.0	24.5
Increase in equity loss	(1.8)	(13.8)
Decrease in non-controlling interest	1.0	2.1
Increase in income tax expense	(19.7)	(73.6)
Other	(1.7)	4.9
Net earnings, 2007	**$ 65.9**	**$ 179.3**

1 Comparable earnings is not defined under Canadian GAAP. 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. Refer to the Non-GAAP Measures section on page 29 of this MD&A for further discussion of comparable earnings, including a reconciliation to net earnings.

Generation gross margins, before mark-to-market gains, increased by $19.5 million for the three months ended Sept. 30, 2007 as a result of higher production, favourable contractual pricing, and lower coal costs at Centralia Coal, and favourable hydro production partially offset by higher coal costs combined with higher unplanned outages at Alberta Thermal, lower margins at Ottawa, and the strengthening of the Canadian dollar relative to the US dollar.

Generation gross margins, before mark-to-market losses, increased by $68.0 million for the nine months ended Sept. 30, 2007 as a result of lower coal costs, increased production at Centralia Coal, favourable pricing in the Alberta and Pacific Northwest markets, and favourable hydro production partially offset by higher coal costs and higher unplanned outages at Alberta Thermal, lower margins in Ottawa, and the strengthening of the Canadian dollar relative to the US dollar.

There are certain contracts in our Generation fleet that do not qualify for hedge accounting. For these contracts we recognize mark-to-market gains and losses resulting from changes in forward prices on existing contracts. These changes in price do not affect the final settlement amount received from these contracts. The fair value of future contracts will continue to fluctuate as market prices change. For the three months ended Sept. 30, 2007, we recognized pre-tax mark-to-market gains of $7.1 million and for the nine months ended Sept. 30, 2007, we recognized pre-tax mark-to-market losses of $32.9 million as a result of changes in forward prices.

CD&M gross margins decreased $5.0 million and $13.0 million for the three and nine months ended Sept. 30, 2007 compared to the same periods in 2006 due to lower margins on trading activities in the Eastern region.

Operations, maintenance, and administration (“OM&A”) costs for the three months ended Sept. 30, 2007 decreased $4.7 million compared to the same period in 2006 due to the timing of expenditures in Generation and lower planned maintenance expenditures.

OM&A costs for the nine months ended Sept. 30, 2007 increased $1.4 million compared to the same period in 2006 primarily due to the impact of the economic dispatch at Centralia Coal in the second quarter of 2006 and increased investment in technological infrastructures partially offset by reduced operational spending across the Generation fleet, and lower planned maintenance expenditures.

Depreciation expense decreased $4.1 million for the three months ended Sept. 30, 2007 compared to 2006 primarily due to more parts replaced during planned maintenance in 2006 and lower depreciation as a result of the impairment of Centralia Gas recorded in 2006 partially offset by the impact of the reclassification of the asset retirement obligation (“ARO”) accretion expense at the Centralia Mine from cost of sales to depreciation.

For the nine months ended Sept. 30, 2007, depreciation expense decreased $8.5 million compared to the same period in 2006 due to the impairment recorded in 2006 on turbines held in inventory and the above noted items.

During the third quarter we sold equipment previously used in our Centralia mining operations with a recorded value of $12.7 million, received proceeds of $16.1 million, and recorded a pre-tax gain of $3.4 million. For the nine months ended we have sold equipment with a book value of $24.3 million, received proceeds of $39.4 million, and recorded a pre-tax gain of $15.1 million.

For the three and nine months ended Sept. 30, 2007, net interest expense decreased $19.0 million and $24.5 million, respectively, mainly due to lower long-term debt levels, higher interest income on cash deposits, and the strengthening of the Canadian dollar relative to the US dollar. For the three and nine months ended Sept. 30, 2007, net debt[1] increased by $64.8 million and decreased by $35.7 million, respectively. Preferred securities of $175.0 million were repaid in the first quarter of 2007.

For the three and nine months ended Sept. 30, 2007, equity loss increased $1.8 million and $13.8 million respectively mainly due to lower margins and higher interest expense as a result of refinancing these subsidiaries.

For the three months ended Sept. 30, 2007, non-controlling interests decreased by $1.0 million due to lower earnings at TransAlta Cogeneration, L.P. (“TA Cogen”) primarily as a result of lower margins at Sheerness and Ottawa.

1 Net debt is defined as short-term debt plus long-term debt including the current portion less cash.

For the nine months ended Sept. 30, 2007, non-controlling interests decreased by $2.1 million due to lower earnings at TA Cogen as a result of lower margins at Ottawa partially offset by higher margins at Sheerness in the second quarter.

Income taxes increased compared to the same period in 2006, due to higher pre-tax income in 2007 and a reduction in tax expense in 2006 due to changes in the Alberta and Federal budgets. The effective tax rates for the quarter and nine months ended Sept. 30, 2007 were 27.2 per cent and 25.2 per cent compared to 9.5 per cent and 18.6 per cent respectively for the same periods in 2006.

CASH FLOW

Cash flow from operating activities for the three months ended Sept. 30, 2007 increased $10.5 million compared to the same period in 2006 due to higher cash earnings in 2007 and cash being consumed in 2006 to build coal inventory at Centralia Coal partially offset by timing of collections of accounts receivable in 2007. In the third quarter we only received two month's worth of revenue under our Power Purchase Agreements ("PPAs") due to contractual timing of these scheduled payments. On Oct. 2, 2007 we received $87.3 million, as contractually scheduled, and these payments will appear in the fourth quarter cash flows.

Cash flow from operating activities for the nine months ended Sept. 30, 2007 increased $242.8 million compared to the same period in 2006 mainly due to higher cash earnings, cash being consumed in 2006 to build coal inventory at Centralia Coal, and the collection of December 2006 revenues, as contractually scheduled, in January 2007.

Due to contractual timing in the fourth quarter, a payment relating to 2007 PPA revenues will not be received until Jan. 2, 2008. While there is variability in the timing of cash collected, during 2007 we will receive twelve months of revenues earned under the PPAs.

At Sept. 30, 2007, our total debt (including non-recourse debt) to invested capital ratio[1] was 47.6 per cent (44.8 per cent excluding non-recourse debt and restricted cash). This is comparable to the Dec. 31, 2006 ratio of 44.5 per cent (41.0 per cent excluding non-recourse debt).

SIGNIFICANT EVENTS

Three months ended Sept. 30, 2007

Normal course issuer bid ("NCIB") program

On Sept. 11, 2007, TransAlta announced its expansion of the NCIB program. The corporation may purchase, for cancellation, up to 20.2 million of its common shares or approximately 10 per cent of the 202.0 million common shares issued and outstanding as at April 23, 2007. The 2007 NCIB program started on May 3, 2007 and will continue until May 2, 2008. Purchases will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the three and nine months ended Sept. 30, 2007, TransAlta purchased 903,600 shares at an average price of $29.65 per share. This purchase price was in excess of the weighted average book value per share of $8.83 per share, resulting in a reduction to retained earnings of $18.8 million.

		9 months ended Sept. 30, 2007
Total shares purchased (in millions)		0.9
Average purchase price per share	$	29.65
Total cash paid (in millions)	$	26.8
Weighted average book value of shares cancelled		8.0
Reduction to retained earnings (in millions)	$	18.8

1 This is a non-GAAP measure. This ratio is further defined as (short-term debt + long-term debt – cash and interest-earning investments) / (debt + preferred securities + non-controlling interests + common equity).

New Brunswick Power Purchase Agreement

On Jan. 19, 2007, we announced a 25 year long-term contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 75 megawatts ("MW") of wind power. We will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills"). Commercial operations are expected to begin by the end of 2008.

On July 17, 2007, we amended our power purchase agreement with New Brunswick Power to increase capacity under the agreement from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills wind power project will also increase by $40 million to $170 million. We also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site. Under the purchase and sale agreement, TransAlta acquired Canadian Hydro's Fairfield Hill wind power site, including the option to develop the site at a future date, for $1.3 million.

Sundance Unit 4 Uprate

The Sundance Unit 4 uprate was completed, adding an estimated 53 MW of generating capacity, with final measurement of capacity to take place in the fourth quarter of 2007.

Greenhouse Gas Emissions Standards

Effective July 1, 2007, the Climate Change and Emissions Management Amendment Act was enacted into law in Alberta. Under the legislation, baselines and targets for greenhouse gas emissions ("GHG") intensity are set on a facility by facility basis. The legislation requires a 12 per cent reduction in carbon emission intensity over a baseline established as at Dec. 31, 2007. New facilities or those in operation for less than three years are exempt, however, upon the fourth year of operations, the facility baseline is established and gradually reduces by year of operation until the eighth year by which emissions must be 12 per cent below the established baseline. Emissions over the baseline are subject to a charge that must be paid annually. The PPAs for our Alberta based coal facilities contain change-in-law provisions that allow us to recover most compliance costs from the PPA customers. After flow through the net compliance costs are estimated to be approximately $3 million in 2007 and $7 million per year thereafter until we are able to meet the targets for GHG emissions under the Act.

Nine months ended Sept. 30, 2007

TransAlta Power, L.P.

On June 18, 2007, TransAlta Power, L.P. ("TransAlta Power") announced that it will record a non-cash charge to earnings in the second quarter and a corresponding reduction in the book value of its equity investment in TransAlta Cogeneration, L.P. ("TA Cogen") to reflect the tax effect of differences between the book and tax values of the assets of TA Cogen. This was as a result of tax legislation which was substantively enacted on June 12, 2007. There is no impact to TransAlta's earnings as the tax effect of these temporary differences has been accounted for in the accounts of TransAlta since its initial investment in TA Cogen.

On May 22, 2007, TransAlta Power announced the commencement of a strategic review, which included seeking proposals from potential buyers. Subsequent to the end of the third quarter, TransAlta Power entered into a support agreement with Cheung Kong Infrastructure Holdings Limited ("CKI") who agreed to acquire all of the outstanding units of TransAlta Power. This offer is further discussed on page 6 under subsequent events.

Dragline deposit

On June 21, 2007, TransAlta Utilities Corporation, a subsidiary of TransAlta Corporation, entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal for the Keephills 3 joint venture project. TransAlta's portion of the total dragline purchase costs are approximately $110 million, with final payments for goods and services due by May 2010. Total anticipated payments under this agreement in 2007 are $16 million.

Keephills 3 Power Plant

On Feb. 26, 2007, we announced that we will be building the 450 MW Keephills 3 coal-fired power plant. The plant will be developed jointly by EPCOR Utilities Inc. ("EPCOR") and TransAlta. The capital cost of the project is expected to be approximately $1.6 billion, including associated mine capital, and is anticipated to begin commercial operations in the first quarter of 2011. TransAlta will own a 50 per cent interest in this unit.

2007 Canadian Federal Budget

The Canadian Federal Budget released on March 19, 2007 proposes to disallow the deductibility of interest on debt incurred to invest in foreign affiliates starting after 2011. Draft legislation was released on Oct. 2, 2007, and we are currently evaluating the impact of this proposed legislation.

SUBSEQUENT EVENTS

TransAlta Power

On Oct. 15, 2007 TransAlta Power, L.P. announced it had entered into an agreement with CKI under which CKI agreed to offer cash of $8.38 per unit to acquire all of the outstanding units of TransAlta Power. The purchase price under the Offer represents a 15.7 per cent premium over the closing trading price of the units on the TSX on Oct. 12, 2007. The transaction is valued at approximately $629 million. This transaction will have no material impact on TransAlta.

Ottawa Power Purchase Agreement

On Oct. 12, 2007, we signed an agreement amending our original power purchase agreement with the Ontario Electricity Financial Corporation (“OEFC”) for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant operations following the expiry of long term natural gas supply contracts. The agreement will be in effect from Nov. 1, 2007 until Dec. 31, 2012.

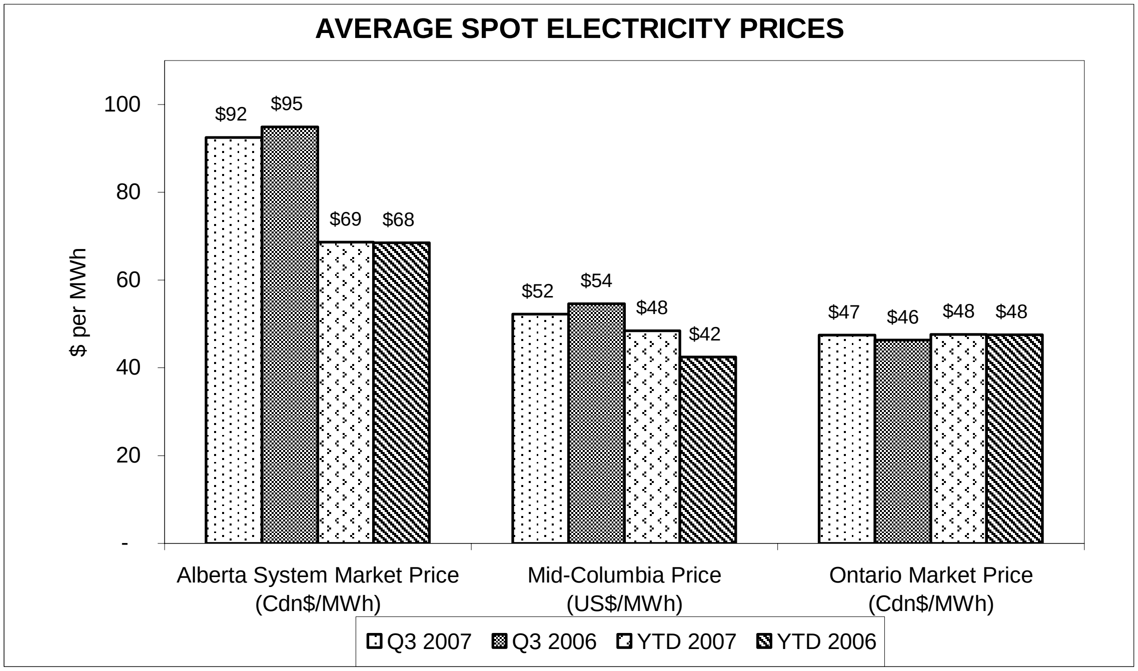
Mexico tax reform

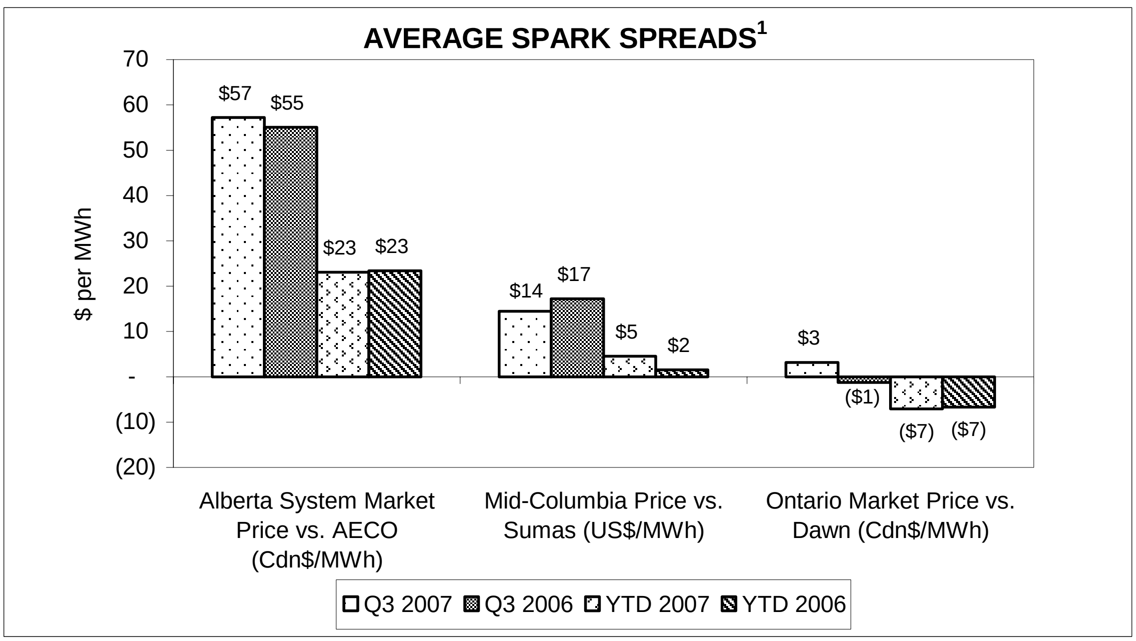
On Oct. 1, 2007, the Mexican Government enacted law replacing the existing asset tax with a new flat tax starting Jan. 1, 2008. The flat tax is a minimum tax whereby the greater of income tax or flat tax is paid. In computing the flat tax, only 50 per cent of the undepreciated tax balance of certain capital assets acquired before Sept. 1, 2007 is deductible over 10 years. In addition, no deduction or credit is permitted in respect of interest expense and net operating losses for income taxes as at Dec. 31, 2007 cannot be carried forward to shelter flat tax. TransAlta is currently assessing the impact of this change.

MARKET PRICES AND SPARK SPREADS

The change in prices of electricity, natural gas, and resulting spark spreads in our three major markets – Alberta, Ontario, and the Pacific Northwest Region of the United States, affect our Generation and Energy Trading businesses.

At the end of third quarter, approximately 12 per cent of the estimated production in 2007 for our gas-fired facilities and two per cent of the estimated 2007 production for our coal-fired facilities have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes 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.





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

For the third quarter, spot prices in Alberta and the Pacific Northwest decreased slightly while Ontario remained comparable to the same period in 2006. Spark spreads decreased in the Pacific Northwest but increased in Alberta and Ontario for the three months ended Sept. 30, 2007 compared to the same period in 2006. The effect of these prices upon the margins from our generating facilities and our trading activities are described in further detail below.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: *Owns and operates hydro, wind, geothermal, 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 annual report for the year ended Dec. 31, 2006). At Sept. 30, 2007, Generation had 8,371 MW of gross generating capacity[1] in operation (7,964 MW net ownership interest) and 374 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, please refer to the MD&A contained in our 2006 annual report.*

During the third quarter we completed an uprate of an estimated 53 MW on Unit 4 of our Sundance facility. However, we are awaiting final technical assessment to take place in the fourth quarter to update the generating capacity in operation.

The results of the Generation segment are as follows:

3 months ended Sept. 30	**2007 Total**	**2007 Per installed MWh**	2006 Total	2006 Per installed MWh
Revenues	**$ 696.2**	**$ 37.98**	$ 635.6	$ 34.69
Fuel and purchased power	**(336.1)**	**(18.33)**	(302.1)	(16.49)
Gross margin	**360.1**	**19.65**	333.5	18.20
Operations, maintenance and administration	**108.2**	**5.90**	119.4	6.52
Depreciation and amortization	**96.0**	**5.24**	100.0	5.46
Taxes, other than income taxes	**4.6**	**0.25**	4.9	0.27
Intersegment cost allocation	**6.8**	**0.37**	7.1	0.39
Operating expenses	**215.6**	**11.76**	231.4	12.64
Operating income	**$ 144.5**	**$ 7.89**	$ 102.1	$ 5.56
Installed capacity (GWh)	**18,332**		18,322	
Production (GWh)	**12,761**		12,420	
Availability (%)	**85.1**		84.1	

9 months ended Sept. 30	**2007 Total**	**2007 Per installed MWh**	2006 Total	2006 Per installed MWh
Revenues	**$ 1,949.4**	**$ 35.45**	$ 1,870.2	34.03
Fuel and purchased power	**(882.7)**	**(16.05)**	(838.6)	(15.26)
Gross margin	**1,066.7**	**19.40**	1,031.6	18.77
Operations, maintenance and administration	**340.9**	**6.20**	352.6	6.41
Depreciation and amortization	**288.3**	**5.24**	296.9	5.40
Taxes, other than income taxes	**15.3**	**0.28**	16.0	0.29
Intersegment cost allocation	**20.5**	**0.37**	21.0	0.38
Operating expenses	**665.0**	**12.09**	686.5	12.48
Operating income	**$ 401.7**	**$ 7.31**	$ 345.1	$ 6.29
Installed capacity (GWh)	**54,986**		54,965	
Production (GWh)	**36,955**		34,915	
Availability (%)	**85.6**		88.6	

1 TransAlta measures 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.

Availability

Availability for the three months ended Sept. 30, 2007 increased to 85.1 per cent from 84.1 per cent compared to the same period in 2006 due to lower unplanned outages at Centralia Coal partially offset by higher planned and unplanned outages at Alberta Thermal and Centralia Gas.

Availability for the nine months ended Sept. 30, 2007 decreased to 85.6 per cent from 88.6 per cent compared to the same period in 2006 primarily due to derating at Centralia Coal due to test burning PRB coal in the first and second quarters of 2007 and due to higher unplanned outages at Alberta Thermal partially offset by lower unplanned outages at Centralia Coal in the third quarter. The underlying availability after adjusting for Centralia Coal derates is 87.3 per cent and 89.3 per cent for the three and nine months ended Sept. 30, 2007, respectively.

Production

Production for the third quarter increased 341 GWh compared to the same period in 2006 as a result of lower unplanned outages at Centralia Coal (690 GWh), and increased hydro production (105 GWh) partially offset by higher planned outages at Alberta Thermal (41 GWh), higher unplanned outages at Alberta Thermal (272 GWh), and lower production at Centralia Gas (119 GWh).

Production for the nine months ended Sept. 30, 2007 increased by 2,040 GWh compared to the same period in 2006 due to the economic dispatch at Centralia Coal in the second quarter of 2006 (1,466 GWh), lower unplanned outages at Centralia Coal in the third quarter of 2007 (690 GWh), increased hydro production (147 GWh), increased customer demand at Fort Saskatchewan (161 GWh), favourable market conditions at Sarnia (187 GWh), lower planned and unplanned outages at Sheerness (60 GWh), and increased production at Ottawa as we curtailed production in the first quarter of 2006 to sell gas (81 GWh) partially offset by higher unplanned outages at Alberta Thermal (534 GWh), lower production at Centralia Gas (156 GWh), and lower PPA customer demand (86 GWh).

Revenue

Revenue increased by $60.6 million for the three months ended Sept. 30, 2007 as compared to the same period in 2006 primarily due to higher production at Centralia Coal ($36.8 million), higher contractual pricing at Centralia Coal ($20.7 million), mark-to-market gains ($7.1 million), increased hydro production and pricing ($9.7 million), and additional revenue from the flow through of carbon compliance costs in Alberta ($11.2 million) partially offset by higher PPA penalties paid during planned outages at Alberta Thermal ($11.4 million), higher unplanned outages at Alberta Thermal ($24.6 million), lower revenue from Ottawa gas sales ($13.4 million), and the strengthening of the Canadian dollar relative to the US dollar ($22.0 million).

In addition to these items, in 2007 we fixed transmission costs between two physical market delivery points at Centralia Coal. Since this transaction requires physical delivery and repurchase of electricity, associated revenues and replacement power costs are shown gross on the statement of income, consistent with generally accepted accounting principles. Therefore, as a result of this transaction, revenues increased $39.6 million and cost of sales increased $40.5 million over the same period in 2006. While the net impact of these two amounts is negative upon gross margin, this transaction resulted in lower overall transmission costs at Centralia Coal which are included in the International margins.

For the nine months ended Sept. 30, 2007 revenue increased $79.2 million due to higher market and contractual pricing combined with increased production at Centralia Coal ($76.6 million), higher production and spark spreads at Poplar Creek in the first quarter ($6.4 million), favourable commercial settlements in the second quarter ($12.0 million), fixing transmission costs through a firm swap between two market delivery points at Centralia Coal ($54.1 million), higher production and increased fuel costs that are recovered from customers at Sarnia ($12.3 million), higher production and pricing at CE Generation LLC (“CE Gen”) ($10.6 million), higher hydro production and pricing ($12.4 million), additional revenue from the flow through of carbon compliance costs in Alberta ($11.2 million), favourable pricing at Alberta Thermal ($12.5 million), and higher revenues at our Australian operations ($8.4 million) partially offset by lower sales of emission credits at Centralia Coal in the first quarter ($7.2 million), mark-to-market losses ($32.9 million), lower revenue from gas sales at Ottawa ($29.2 million), higher unplanned outages at Alberta Thermal ($39.1 million), higher penalties paid during planned outages at Alberta Thermal ($8.0 million), and the strengthening of the Canadian dollar relative to the US dollar ($23.1 million).

Fuel and purchased power

Fuel and purchased power increased by $34.0 million for the three months ended Sept. 30, 2007 compared to the same period in 2006 due to higher coal costs at Alberta Thermal ($6.0 million), new costs for carbon compliance in Alberta ($12.8 million), fixing transmission costs between two delivery points at Centralia Coal ($40.5 million), and increased production at Centralia Coal ($21.6 million) partially offset by lower coal costs at Centralia Coal ($29.1 million), lower gas purchases at Ottawa in 2006 ($9.3 million), reduced production at Alberta Thermal ($3.8 million), and the strengthening of the Canadian dollar relative to the US dollar ($11.4 million).

For the nine months ended Sept. 30, 2007 fuel and purchased power increased **$**44.1 million due to higher coal costs at Alberta Thermal ($25.3 million), new costs for carbon compliance in Alberta ($12.8 million), fixing transmission costs between two delivery points at Centralia Coal ($55.5 million), increased fuel costs and production at CE Gen ($7.9 million) and Sarnia ($13.2 million), increased production at Centralia Coal ($16.6 million), and higher replacement power prices at Centralia Coal ($8.4 million) partially offset by lower fuel costs at Centralia Coal ($61.2 million), incremental gas purchases at Ottawa in 2006 ($14.9 million), reduced production at Alberta Thermal ($9.3 million), and the strengthening of the Canadian dollar relative to the US dollar ($11.9 million).

Operations, maintenance and administration expense

For the three months ended Sept. 30, 2007, OM&A expense decreased by $11.2 million primarily due to the timing of routine maintenance expenditures and lower planned maintenance expenditures.

For the nine months ended Sept. 30, 2007, OM&A expense decreased by $11.7 million primarily due to lower operational spending and planned maintenance expenditures partially offset by savings realized from the economic dispatch at Centralia Coal in the second quarter of 2006.

Depreciation expense

Depreciation expense decreased $4.0 million for the three months ended Sept. 30, 2007 compared to 2006 primarily due to lower depreciation at Centralia Gas as a result of the impairment recorded in 2006 ($1.2 million), lower depreciation as a result of parts replaced during planned and unplanned outages in 2006 ($5.0 million), and the strengthening of the Canadian dollar versus the US dollar ($2.5 million) partially offset by the impact of reclassification of the ARO accretion expense at the Centralia Mine from cost of sales to depreciation ($2.7 million).

For active mines, accretion expense related to ARO is included in cost of sales. However, the Centralia mine is currently considered to be inactive and therefore, accretion expense is now classified as part of depreciation expense. In 2006, $2.1 million and $6.5 million of accretion expense related to the Centralia mine was recorded in cost of sales, respectively, for the three and nine months ended Sept. 30, 2006.

For the nine months ended Sept. 30, 2007, depreciation expense decreased $8.6 million compared to the same period in 2006, due to the impairment recorded in 2006 on turbines held in inventory ($9.2 million), lower depreciation at Centralia Gas ($3.6 million), the strengthening of the Canadian dollar versus the US dollar ($2.8 million), and more parts replaced during planned maintenance in 2006 ($6.7 million) partially offset by the reclassification of ARO accretion at the Centralia Mine ($7.1 million) and increased depreciation as a result of capital spending in 2006 ($3.1 million).

Planned maintenance

The table below shows the amount of planned maintenance capitalized and expensed in the three and nine months ended Sept. 30, 2007 and 2006, excluding CE Gen and Mexico:

	Coal		Gas and Hydro		Total	
3 months ended Sept. 30	**2007**	2006	**2007**	2006	**2007**	2006
Capitalized	**$ 21.0**	$ 14.4	**$ 1.3**	$ 6.4	**$ 22.3**	$ 20.8
Expensed	**21.3**	23.2	**0.7**	0.7	**22.0**	23.9
	$ 42.3	$ 37.6	**$ 2.0**	$ 7.1	**$ 44.3**	$ 44.7
GWh lost	**606**	565	**54**	1	**660**	566

	Coal		Gas and Hydro		Total	
9 months ended Sept. 30	**2007**	2006	**2007**	2006	**2007**	2006
Capitalized	**$ 50.1**	$ 47.1	**$ 10.6**	$ 18.8	**$ 60.7**	$ 65.9
Expensed	**49.8**	53.4	**1.4**	2.0	**51.2**	55.4
	$ 99.9	$ 100.5	**$ 12.0**	$ 20.8	**$ 111.9**	$ 121.3
GWh lost	**1,854**	1,948	**126**	106	**1,980**	2,054

For the three months ended Sept. 30, 2007, production lost due to planned maintenance increased by 94 GWh compared to the same period in 2006 mainly due to higher planned outages at Alberta Thermal and timing of maintenance at our gas-fired facilities relative to 2006.

For the nine months ended Sept. 30, 2007, production lost due to planned maintenance decreased by 74 GWh due to lower planned outages at Sheerness (41 GWh), and Centralia Coal (80 GWh) partially offset by higher planned outages at Alberta Thermal (28 GWh).

For the three months ended Sept. 30, 2007 total capitalized and expensed maintenance costs are comparable to the same period in 2006.

For the nine months ended Sept. 30, 2007 total capital and expensed maintenance costs decreased compared to the same period in 2006 due to lower planned maintenance at our gas assets.

Generation gross margins

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

3 months ended Sept. 30, 2007	**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	**7,833**	**11,320**	**$ 279.3**	**$ 111.0**	**$ 168.3**	**$ 24.67**	**$ 9.81**	**$ 14.86**
Eastern Canada	**907**	**1,793**	**91.1**	**62.2**	**$ 28.9**	**50.81**	**34.69**	**16.12**
International	**4,021**	**5,219**	**325.8**	**162.9**	**$ 162.9**	**62.43**	**31.21**	**31.22**
	12,761	**18,332**	**$ 696.2**	**$ 336.1**	**$ 360.1**	**$ 37.98**	**$ 18.33**	**$ 19.65**

3 months ended Sept. 30, 2006	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	8,058	11,310	$ 293.0	$ 96.5	$ 196.5	$ 25.91	$ 8.53	$ 17.38
Eastern Canada	885	1,793	103.5	72.4	$ 31.1	57.72	40.39	17.33
International	3,477	5,219	239.1	133.2	$ 105.9	45.81	25.52	20.29
	12,420	18,322	$ 635.6	$ 302.1	$ 333.5	$ 34.69	$ 16.49	$ 18.20

9 months ended Sept. 30, 2007	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	**24,662**	**33,949**	**$ 933.2**	**$ 327.4**	**$ 605.8**	**$ 27.49**	**$ 9.64**	**$ 17.85**
Eastern Canada	**2,716**	**5,380**	**324.8**	**222.1**	**$ 102.7**	**60.37**	**41.28**	**19.09**
International	**9,577**	**15,656**	**691.4**	**333.2**	**$ 358.2**	**44.16**	**21.28**	**22.88**
	36,955	**54,986**	**$ 1,949.4**	**$ 882.7**	**$ 1,066.7**	**$ 35.45**	**$ 16.05**	**$ 19.40**

9 months ended Sept. 30, 2006	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	24,849	33,928	$ 918.0	$ 290.8	$ 627.2	$ 27.06	$ 8.57	$ 18.49
Eastern Canada	2,458	5,381	343.5	225.9	117.6	63.84	41.98	21.86
International	7,608	15,656	608.7	321.9	286.8	38.88	20.56	18.32
	34,915	54,965	$ 1,870.2	$ 838.6	$ 1,031.6	$ 34.03	$ 15.26	$ 18.77

Western Canada

Our Western Canada assets consist of five coal units, three gas-fired facilities, thirteen hydro facilities, and three wind farms with a total gross generating capacity of 5,169 MW (4,884 MW net of ownership interest). We are currently constructing a 450 MW coal-fired unit at our Keephills facility under a joint venture with EPCOR and we have added an estimated 53 MW of capacity to Unit 4 at our Sundance facility in September of 2007, with final technical assessment to take place in the fourth quarter. The additional unit at our Keephills facility is scheduled to enter commercial production in 2011.

Our Sundance, Keephills, and Sheerness plants and hydro facilities operate under PPAs with a gross generating capacity of 3,977 MW (3,782 MW net of ownership interest). Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability and an excess energy payment for power production above committed capacity. Additional capacity added to these units which are not included in capacity covered by the PPAs are sold on the merchant market.

Our Wabamun, Genesee 3, Summerview, and a portion of our Poplar Creek facilities sell their production on the merchant spot market. In order to manage our exposure to changes in spot electricity prices as well as capture value, we use hedges to guarantee prices for production.

Due to their close physical proximity, three of our coal units, Sundance, Keephills, and Wabamun, are operated and managed collectively and are referred to as “Alberta Thermal.”

Our Castle River, McBride Lake, Meridian, Fort Saskatchewan, and a significant portion of our Poplar Creek assets earn revenues under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam as well as for ancillary services. These contracts are for an original term of at least ten years and payments do not fluctuate significantly with changes in levels of production.

Production for the three months ended Sept. 30, 2007 decreased 225 GWh compared to the same period in 2006 due to higher planned and unplanned outages at Alberta Thermal (313 GWh) partially offset by higher hydro volumes (105 GWh).

For the nine months ended Sept. 30, 2007, production decreased 187 GWh due to higher unplanned outages at Alberta Thermal (534 GWh) partially offset by increased customer demand at Fort Saskatchewan (161 GWh), increased hydro production (147 GWh), and lower planned and unplanned outages at Meridian (43 GWh).

Gross margin for the three months ended Sept. 30, 2007 decreased $28.2 million ($2.52 per installed MWh), due to higher coal costs ($6.0 million), higher planned and unplanned outages at Alberta Thermal ($32.3 million), and the net effect of carbon compliance costs ($1.5 million) partially offset by higher hydro prices and volumes ($9.5 million), and higher prices ($3.8 million).

Gross margin for the nine months ended Sept. 30, 2007 decreased $21.4 million ($0.64 per installed MWh) due to higher coal costs ($25.3 million), higher planned and unplanned outages at Alberta Thermal ($42.8 million), and the net effect of carbon compliance costs ($1.5 million) partially offset by higher hydro production and pricing ($12.9 million), lower planned and unplanned outages at Sheerness ($3.4 million), higher prices ($14.6 million), favourable production at Meridian ($3.1 million), and favourable commercial settlements in the second quarter ($12.0 million).

Eastern Canada

Our Eastern Canada assets consist of four gas fired facilities with a total gross generating capacity of 819 MW (697 MW net of ownership interest). All four facilities earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Kent Hills, a 96 MW wind farm located in New Brunswick, is currently under development and is scheduled to begin commercial operations in 2008.

Production for the three months ended Sept. 30, 2007 increased 22 GWh primarily due to favourable market conditions and customer demand at Sarnia.

Production for the nine months ended Sept. 30, 2007 increased 258 GWh primarily resulting from favourable market conditions and customer demand at Sarnia (187 GWh) and increased production at Ottawa due to gas sales in the first quarter of 2006 (81 GWh).

For the three months ended Sept. 30, 2007, gross margins decreased $2.2 million ($1.21 per installed MWh) due to lower gas sales at Ottawa ($4.1 million) partially offset by favourable pricing and production at Sarnia ($1.6 million).

For the nine months ended Sept. 30, 2007, gross margins decreased $14.9 million ($2.77 per installed MWh) as a result of lower gas sales at Ottawa ($14.2 million).

International

Our International assets consist of gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,083 MW and gas and diesel fired assets in Australia with a generating capacity of 300 MW. 378 MW of our United States assets are operated by CE Gen, a joint venture owned 50 per cent by TransAlta.

Our Centralia Coal, Centralia Gas, Binghamton, Power Resources, Skookumchuck, and one unit of our Imperial Valley assets are merchant facilities. To reduce the volatility and risk in merchant markets, we use a variety of physical and financial hedges to secure prices received for electrical production. The remainder of our international facilities operate under long-term contracts.

For the three months ended Sept. 30, 2007, production increased 544 GWh due to lower unplanned outages at Centralia Coal (690 GWh) partially offset by lower production at Centralia Gas as a result of unfavourable market conditions (119 GWh).

For the nine months ended Sept. 30, 2007, production increased 1,969 GWh due to lower unplanned outages at Centralia Coal (690 GWh), and higher production at Centralia Coal due to the facility being economically dispatched in the second quarter of 2006 (1,466 GWh) partially offset by lower production at Centralia Gas (156 GWh).

For the three months ended Sept. 30, 2007, gross margins increased $57.0 million ($10.93 per installed MWh) compared to the same period in 2006 due to increased production at Centralia Coal in the third quarter in 2006 ($15.1 million), favourable contractual pricing at Centralia Coal ($16.6 million), mark-to-market gains ($8.7 million), and lower coal costs ($29.1 million) partially offset by the strengthening of the Canadian dollar ($10.7 million).

For the nine months ended Sept. 30, 2007 gross margins increased $71.4 million ($4.56 per installed MWh) due to favourable market and contractual pricing at Centralia Coal ($34.9 million), increased production at Centralia Coal ($19.9 million), lower coal costs at Centralia ($61.2 million), and favourable exchange rates and margins in Australia ($4.6 million) partially offset by the sale of emission credits at Centralia Coal in the first quarter of 2006 ($7.2 million), higher replacement power prices in the second quarter ($8.4 million), mark-to-market losses ($31.3 million) and the strengthening of the Canadian dollar compared to the US dollar ($11.2 million).

CORPORATE DEVELOPMENT AND MARKETING: *derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta owned generation assets. CD&M also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas, coal and transmission capacity to effectively manage available generating capacity as well as fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Key performance indicators for CD&M's proprietary trading include margins, while remaining within value at risk limits.*

Our Energy Trading activities utilize a variety of instruments to manage risk, earn trading revenue and gain market information. Our trading strategies consist of shorter-term physical and financial trades in regions where we have assets and the markets that interconnect with those regions. The portfolio primarily consists of physical and financial derivative instruments including forwards, swaps, futures, and options in various commodities. These contracts meet the definition of trading activities and have been accounted for at fair value under Canadian GAAP. Changes in the fair value of the portfolio are recognized in income in the period they occur.

While trading products are generally consistent between periods, positions held and resulting earnings impacts will vary due to current and forecasted external market conditions. Positions for each region are established based on the market conditions and the risk reward ratio established for each trade at the time they are transacted. Results, therefore, will vary regionally or by strategy from one reported period to the next.

OM&A costs incurred within CD&M are allocated to the Generation segment based on an estimate of operating expenses and an estimated percentage of resources dedicated to providing support and analysis. This fixed fee inter-segment allocation is represented as a cost recovery in CD&M and an operating expense within Generation.

Previously, we recorded revenues and related costs for contracts settled in real-time physical markets on a gross basis. However, all of these contracts are held for trading, irrespective of the market in which they are settled. Therefore, we have concluded that it is more representative of the actual trading activities of CD&M to report the results of these contracts on a net basis, consistent with FASB Emerging Issues Task Force (EITF 02-3) "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

Prior year balances have been reclassified to conform with the current year's presentation, as shown below. Current year balances have been prepared in the following table using previously disclosed methodologies for information purposes only.

	3 months ended		9 months ended	
	Sept. 30, 2007	Sept. 30, 2006	Sept. 30, 2007	Sept. 30, 2006
Revenue	$ 73.9	$ 48.4	$ 196.1	$ 146.5
Trading purchases	(58.5)	(28.0)	(153.7)	(91.1)
Net revenue	$ 15.4	$ 20.4	$ 42.4	$ 55.4

The results of the CD&M segment, with all trading results presented net, are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Gross margin	**$ 15.4**	$ 20.4	**$ 42.4**	$ 55.4
Operations, maintenance and administration	**9.7**	8.8	**26.6**	25.2
Depreciation and amortization	**0.4**	0.3	**1.1**	1.0
Intersegment cost allocation	**(6.8)**	(7.1)	**(20.5)**	(21.0)
Operating expenses	**3.3**	2.0	**7.2**	5.2
Operating income	**$ 12.1**	$ 18.4	**$ 35.2**	$ 50.2

For the three months ended Sept. 30, 2007, gross margin decreased $5.0 million relative to the same period in 2006 due to decreased trading results in the Eastern region in 2007 resulting from gas market volatility and unanticipated weather changes.

For the nine months ended Sept. 30, 2007, gross margins decreased $13.0 million compared to the same period in 2006 due to decreased gas and Eastern region trading margins in 2007 as a result of natural gas market volatility, unanticipated weather changes, and the strengthening of the Canadian dollar relative to the US dollar.

OM&A costs for the three and nine months ended Sept. 30, 2007 increased $0.9 million and $1.4 million, respectively, due to increased staff compensation costs.

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

NET INTEREST EXPENSE

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Interest on long-term debt	**$ 35.6**	$ 41.1	**$ 111.0**	$ 109.9
Interest on short-term debt	**6.4**	4.1	**18.9**	10.3
Interest on preferred securities	**-**	3.4	**-**	10.2
Interest income	**(11.8)**	(1.0)	**(26.1)**	(4.3)
Capitalized interest	**(1.6)**	-	**(2.2)**	-
Net interest expense	**$ 28.6**	$ 47.6	**$ 101.6**	$ 126.1

For the three months ended Sept. 30, 2007, net interest expense was $19.0 million lower than the comparable period in 2006 due to lower long-term debt levels ($2.7 million) and the strengthening of the Canadian dollar relative to the US dollar ($2.0 million), redemption of preferred securities in 2007 ($3.4 million), the interest gain on the unwind of an interest rate swap in the third quarter ($4.4 million), and higher interest income from cash deposits ($5.6 million) partially offset by higher short-term debt balances ($2.3 million).

For the nine months ended Sept. 30, 2007, net interest expense was $24.5 million lower than the comparable period in 2006 due to redemption of preferred securities in 2007 ($10.2 million), higher interest on cash deposits ($17.8 million), and the strengthening of the Canadian dollar relative to the US dollar ($7.6 million), the interest gain on the unwind of an interest rate swap in the third quarter ($4.4 million), and lower long-term debt balances ($4.1 million) partially offset by higher short-term debt balances ($8.6 million), and the interest gain on the unwind of a net investment hedge in 2006 which was recorded as part of interest expense on long-term debt ($10.2 million).

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests in the three months ended Sept. 30, 2007 decreased $1.0 million compared to the same period in 2006 due to higher unplanned outages at Sheerness and from lower margins at Ottawa.

For the nine months ended Sept. 30, 2007, earnings attributable to non-controlling interests decreased $2.1 million due to lower margins at Ottawa partially offset by higher margins at Sheerness in the second quarter of 2007.

EQUITY LOSS

As required under Accounting Guideline 15, *Consolidation of Variable Interest Entities*, of the Canadian Institute of Chartered Accountants (“CICA”), our Mexican operations are accounted for as equity subsidiaries. However, these plants are owned by TransAlta and managed as part of the Generation segment. The table below summarizes key information from these operations.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Availability (%)	**94.9**	98.8	**95.6**	91.7
Production (GWh)	**917**	894	**2,356**	2,382
Equity loss	**$ (3.2)**	$ (1.4)	**$ (14.2)**	$ (0.4)
Capital expenditures	**$ -**	$ 1.0	**$ 1.0**	$ 9.0
Operating cash flow	**$ 2.3**	$ 5.2	**$ 1.4**	$ 6.5
Interest expense	**$ 5.9**	$ 2.6	**$ 21.8**	$ 13.7

	Sept. 30, 2007	Dec. 31, 2006
Total assets	**$ 451.3**	$ 526.9
Total liabilities	**$ 332.0**	$ 404.1

For the three months ended Sept. 30, 2007 availability decreased due to higher unplanned outages at Campeche. For the nine months ended Sept. 30, 2007 availability increased primarily due to lower planned maintenance at Chihuahua.

For the three months ended Sept. 30, 2007 production increased slightly due to higher customer demand at Chihuahua and Campeche partially offset by higher unplanned outages at Campeche. For the nine months ended Sept. 30, 2007 production decreased due to lower customer demand and higher unplanned outages at Campeche partially offset by lower planned outages at Chihuahua.

For the three months ended Sept. 30, 2007, equity loss increased $1.8 million due to lower margins ($0.5 million), and increased costs as a result of refinancing these subsidiaries in 2006 ($2.8 million) partially offset by reduced operating costs ($0.8 million).

For the nine months ended Sept. 30, 2007, equity loss increased $13.8 million due to lower margins ($3.9 million), increased depreciation as a result of capital spending on planned maintenance in 2006 ($3.3 million), timing of routine maintenance and other operating expenses ($1.8 million), and increased interest costs as a result of refinancing these subsidiaries in 2006 ($14.6 million) partially offset by the recognition of deferred financing fees in 2006 ($7.2 million) and a loss incurred on unwinding a cross-currency swap in 2006 ($1.6 million).

INCOME TAXES

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Earnings before income taxes [1]	**$ 89.3**	$ 39.0	**$ 228.5**	$ 166.5
Turbine impairment	**-**	-	**-**	9.6
Earnings before income taxes and turbine impairment [1]	**$ 89.3**	$ 39.0	**$ 228.5**	$ 176.1
Income tax prior to adjustment for rate change [1]	**23.4**	3.7	**56.9**	30.9
Change in tax rate related to prior periods	**-**	-	**(7.7)**	(55.3)
Income tax expense (recovery) per financial statements	**23.4**	3.7	**$ 49.2**	$ (24.4)
Net income	**$ 65.9**	**$ 35.3**	**$ 179.3**	**$ 190.9**
Effective tax rate (%)	**26.2**	**9.5**	**24.9**	**18.6**

1 Eanings before income taxes is not defined under Canadian GAAP.

As a result of the Tax Fairness Plan, Canadian corporate tax rates were reduced by 0.5 per cent beginning in 2011, resulting in a reduction of tax expense in the second quarter of 2007 of $7.7 million which reflected the impact of these changes on prior years' earnings.

In 2006, as a result of the Alberta and Federal budgets, comparable tax rates were reduced, resulting in a reduction of future tax expense of $55.3 million which reflected the impact of these changes on prior years' earnings.

Tax expense, excluding the impact of the change in tax rate related to prior periods, increased in the three and nine months ended Sept. 30, 2007 from the same period in 2006 due to an increase in pre-tax income earnings and the effect of the change in mix of jurisdictions in which pre-tax income is earned.

FINANCIAL POSITION

The following chart outlines significant changes in the consolidated balance sheet from Dec. 31, 2006 to Sept. 30, 2007:

	Increase/ (Decrease)	Explanation of change
Cash and cash equivalents	$ (5.8)	Refer to Consolidated Statements of Cash Flows
Accounts receivable	(107.0)	Timing of receipt of contractually scheduled payments
Prepaid expenses	8.7	Timing of insurance premiums and other prepaids
Inventory	(16.2)	Lower inventory balances at Centralia Coal
Restricted cash	(86.3)	Decrease in exchange rates and return of funds to TransAlta
Risk management assets (current and long-term)	86.7	Adopting new accounting standards on financial instruments and from price changes
Property, plant and equipment, net	(18.6)	Strengthening of the Canadian dollar compared to the U.S. dollar and depreciation expense partially offset by capital additions
Goodwill	(10.8)	Change in foreign exchange rates
Assets held for sale, net	(68.7)	Assets retained for use in reclamation activities and for use in operations at the Highvale mine combined with sale of other assets
Intangible assets	(68.0)	Amortization expense and the strengthening of the Canadian dollar
Short-term debt	59.1	Net increase in short-term debt
Accounts payable and accrued liabilities	19.4	Timing of planned maintenance activities and other operational payments
Income taxes payable	(11.0)	Paid installments offset by current tax provision
Recourse long-term debt (including current portion)	(61.0)	Scheduled debt payments and decrease in exchange rates
Non-recourse long-term debt (including current portion)	(72.3)	Scheduled debt payments and decrease in exchange rates
Risk management liabilities (current and long-term)	345.4	Result of adopting new accounting standards on financial instruments and from price changes
Deferred credits and other long-term liabilities (including current portion)	(58.9)	Normal accretion expense less liabilities settled and payment of Centralia mine closure costs
Net future income tax liabilities (including current portions)	(60.4)	Tax effect of adjustments related to new accounting standards on financial instruments
Non-controlling interests	(29.0)	Distributions in excess of earnings
Preferred securities (including current portion)	(175.0)	Preferred securities redeemed in 2007
Shareholders' equity	(237.8)	Adoption of new accounting standards, shares redeemed under the NCIB and dividends declared partially offset by net earnings and shares issued

FINANCIAL INSTRUMENTS

On Jan. 1, 2007, we adopted four new accounting standards that were issued by the CICA: Section 1530, *Comprehensive Income*; Section 3855, *Financial Instruments – Recognition and Measurement*; Section 3861, *Financial Instruments – Disclosure and Presentation*; and Section 3865, *Hedges*. We adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income ("AOCI").

Section 1530 introduces comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). OCI represents changes in shareholders' equity during a period arising from transactions and other events with non-owner sources and includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, net of hedging activities, and changes in the fair value of the effective portion of cash flow hedging instruments.

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the consolidated balance sheet when we become a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value upon initial recognition except for certain related party transactions.

To present comparable 2006 balance sheet figures, prior year balances for foreign currency and interest rate financial instruments were reclassified. Short-term and long-term risk management assets were increased by $11.2 million and $43.2 million respectively, and current and long-term portions of other assets were reduced by the corresponding amounts. Short-term and long-term risk management liabilities were increased by $2.1 million and $13.0 million respectively, and current and long-term portions of deferred credits and other long-term liabilities were decreased by the corresponding amounts. As required under Section 1530, cumulative translation loss of $64.5 million was reclassified as the opening balance of AOCI.

The majority of the changes were reflected in the carrying value of cash flow hedges included in CD&M risk management assets and liabilities as well as in financial instruments used as hedges of debt and net investment of self-sustaining foreign subsidiaries. The impact of adopting these standards to our Dec. 31, 2006 balance sheet is outlined below:

	Price Risk Assets		Price Risk Liabilities		
	Current	Long-Term	Current	Long-Term	Net
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of CD&M net risk management assets (liabilities) outstanding at Dec. 31, 2006	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

The gross and net of tax impact of adopting these standards to the opening balance of AOCI are outlined below:

Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ 90.9
Fair value of CD&M net risk management liabilities outstanding at Dec. 31, 2006	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	47.7
Total fair value of risk management liabilities	(173.5)
Change in fair value	(264.4)
Tax	(87.1)
Adjustment to opening Accumulated Other Comprehensive loss from fair values	$ (177.3)
Cumulative Translation Adjustment	(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$ (241.8)

The impact of these new accounting standards on our risk management assets and liabilities is described in more detail below along with the changes in the values of these assets and liabilities in the current period.

Section 3861 outlines disclosure requirements that are designed to enhance financial statement users' understanding of the significance of financial instruments to an entity's financial position, performance and cash flows. The presentation requirements outlined in this Section have been adopted to our financial instruments presentation and related disclosure.

RISK MANAGEMENT ASSETS AND LIABILITIES

Our risk management assets and liabilities are comprised of two major types: (1) those that are used in the CD&M and Generation segments in relation to energy trading activities, commodity hedging activities, and other contracting activities and (2) those used in the hedging non-energy marketing transactions, debt, and the net investment in self-sustaining foreign subsidiaries. The changes in each of these are described below.

Energy Trading

Our energy trading risk management assets and liabilities represent the fair value of unsettled (unrealized) CD&M transactions and certain Generation contracting activities that are accounted for on a fair value basis. Contracts qualifying for hedge accounting are identified as “Hedges”. All other contracts are identified as “Non-Hedges”. With the exception of physical transmission contracts and gas storage assets, the fair value of all energy trading activities is based on quoted market prices or model valuations.

The following table shows the balance sheet classifications for energy trading risk management assets and liabilities separately by source of valuation:

Balance Sheet - Energy Trading	**Sept. 30, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to energy trading
Risk management assets				
- Current	**$ 4.2**	**$ 37.2**	**$ 41.4**	$ 61.0
- Long-term	**(1.8)**	**2.4**	**0.6**	21.9
Risk management liabilities				
- Current	**(77.6)**	**(30.6)**	**(108.2)**	(30.3)
- Long-term	**(243.1)**	**(0.8)**	**(243.9)**	(1.0)
Net risk management assets (liabilities) outstanding	**$ (318.3)**	**$ 8.2**	**$ (310.1)**	$ 51.6

As a result of adopting new accounting standards on financial instruments, as described on page 17, risk management assets and liabilities receiving hedge accounting are recorded at fair value. The impact upon previously reported values is shown in the table below along with the changes in those values during the first nine months of 2007:

	Hedges		**Non-Hedges**		
Change in fair value of net assets (liabilities)	**Fair value (Market)**	**Fair value (Model)**	**Fair value (Market)**	**Fair value (Model)**	**Total**
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	**$ 51.6**
Net risk management liabilities outstanding at Dec. 31, 2006 - *fair value* [1]	(253.0)	(19.8)	52.7	(1.1)	**(221.2)**
Contracts realized, amortized or settled during the period	23.8	2.7	(30.2)	(2.6)	**(6.3)**
Changes in values attributable to market price and other market changes	(52.7)	(8.8)	5.5	(1.9)	**(57.9)**
New contracts entered into during the current period	(9.6)	-	(6.3)	5.6	**(10.3)**
Changes in foreign exchange values	(18.2)	-	3.7	0.1	**(14.4)**
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	-	(17.3)	-	**-**
Net risk management assets (liabilities) outstanding at Sept. 30, 2007 - *fair value*	**$ (292.4)**	**$ (25.9)**	**$ 8.1**	**$ 0.1**	**$ (310.1)**

[1] *As a result of adopting new accounting standards*

For the nine months ended Sept. 30, 2007, the fair value of our net risk management assets associated with hedge positions decreased $45.5 million compared to Dec. 31, 2006 primarily due to value changes associated with contracts in existence at both Dec. 31, 2006 and Sept. 30, 2007, and the change in value of contracts settled in 2007. Changes in net risk management assets and liabilities for hedge positions are reflected within the gross margin of the Generation business segment to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until the delivery date of the underlying product and contract settlement occurs.

For the nine months ended Sept. 30, 2007, the fair value of our net risk management liabilities associated with non-hedge positions decreased $43.5 million compared to Dec. 31, 2006 primarily due to the value of contracts settled during the 2007, and the value of contracts no longer receiving hedge accounting. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of both the CD&M and the Generation business segments.

The anticipated timing of settlement (cash received) of the above contracts over each of the next five calendar years and thereafter are as follows:

		2007	2008	2009	2010	2011	2012 and thereafter	Total
Hedges	Fair value based on market prices	$ (8.7)	$ (100.7)	$ (110.0)	$ (59.4)	$ (12.0)	$ (1.6)	**$ (292.4)**
	Fair value based on models	(1.4)	(6.5)	(8.2)	(7.4)	(2.4)	-	**$ (25.9)**
		$ (10.1)	**$ (107.2)**	**$ (118.2)**	**$ (66.8)**	**$ (14.4)**	**$ (1.6)**	**$ (318.3)**
Non-Hedges	Fair value based on market prices	$ 3.5	$ 4.4	$ 0.2	$ -	$ -	$ -	**$ 8.1**
	Fair value based on models	(1.3)	1.3	0.1	-	-	-	**$ 0.1**
		$ 2.2	**$ 5.7**	**$ 0.3**	**$ -**	**$ -**	**$ -**	**$ 8.2**
Grand total		**$ (7.9)**	**$ (101.5)**	**$ (117.9)**	**$ (66.8)**	**$ (14.4)**	**$ (1.6)**	**$ (310.1)**

Hedge transactions currently relate solely to Generation asset contracts consisting primarily of transactions under five years in duration. Contracts in excess of five years have been transacted with additional authorizations and strict controls.

Non-hedge transactions extending past 2008 are generally Generation asset-backed contracts that do not qualify for hedge accounting and have a low risk profile including long-term fixed for floating power swaps and heat rate swaps. Our Energy Trading activities are mainly transactions under 18 months in duration, thereby reducing credit risk and working capital requirements compared to longer term transactions.

Other Risk Management Assets and Liabilities

As a result of adopting new accounting standards on financial instruments certain risk management assets and liabilities used in hedging non-energy marketing transactions, debt, and the net investment in self-sustaining foreign subsidiaries were recorded at fair value.

The following table shows the balance sheet classifications for other risk management assets and liabilities separately by source of valuation:

Balance Sheet - Other	**Sept. 30, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to non-energy trading
Risk management assets				
- Current	**$ 84.6**	**$ 2.9**	**$ 87.5**	$ 11.2
- Long-term	**94.5**	**-**	**94.5**	43.2
Risk management liabilities				
- Current	**(15.7)**	**(1.6)**	**(17.3)**	(2.1)
- Long-term	**(6.4)**	**(16.0)**	**(22.4)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 157.0**	**$ (14.7)**	**$ 142.3**	$ 39.3

As a result of adopting new accounting standards on financial instruments risk management assets and liabilities receiving hedge accounting were recorded at fair value. The impact upon previously reported values is shown below along with changes in those values during the first nine months of 2007:

	Hedges	**Non-Hedges**	**Total**
Net other risk management assets (liabilities) at Dec. 31, 2006 - *as reported*	$ 50.1	$ (10.8)	$ 39.3
Net other risk management assets (liabilities) at Dec. 31, 2006 - *fair value* [1]	58.0	(10.3)	47.7
Contracts realized, amortized or settled during the period	(5.7)	(0.1)	(5.8)
Changes in values attributable to market price and other market changes	91.8	(4.6)	87.2
New contracts entered into during the current period	12.9	0.3	13.2
Net other risk management assets (liabilities) outstanding at Sept. 30, 2007 - *fair value*	$ 157.0	$ (14.7)	$ 142.3

[1] *As a result of adopting new accounting standards*

For the nine months ended Sept. 30, 2007, the fair value of our net risk management liabilities associated with non-hedge positions increased $4.5 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for non-hedge positions are reflected within interest expense.

For the nine months ended Sept. 30, 2007, the fair value of our net risk management assets associated with hedge positions increased $99.0 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent 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, change in ownership, liquidation or reduction in the net investments of the foreign operation, or financial instrument being hedged.

The anticipated timing of settlement (cash received) of the above contracts over each of the next five calendar years and thereafter are as follows:

	2007	2008	2009	2010	2011 and thereafter	Total
Hedges	$ 37.2	$ 30.1	$ 62.1	$ 14.7	$ 13.0	$ 157.1
Non-hedges	1.2	-	(16.0)	-	-	(14.8)
	$ 38.4	$ 30.1	$ 46.1	$ 14.7	$ 13.0	$ 142.3

Total Balances

The overall balance reported in risk management assets and liabilities are shown below:

Balance Sheet - Totals	Sept. 30, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	$ 41.4	$ 87.5	$ 128.9	$ 61.0	$ 11.2	$ 72.2
- Long-term	0.6	94.5	95.1	21.9	43.2	65.1
Risk management liabilities						
- Current	(108.2)	(17.3)	(125.5)	(30.3)	(2.1)	(32.4)
- Long-term	(243.9)	(22.4)	(266.3)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	$ (310.1)	$ 142.3	$ (167.8)	$ 51.6	$ 39.3	$ 90.9

The corporation seeks to actively manage its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts and regularly monitors these exposures after entering into these contracts. Detailed assessments are made of the credit quality of all counterparties and, where appropriate, corporate guarantees, and/or letters of credit are obtained to support the ultimate collection of these receivables. See Risk Factors and Risk Management in the MD&A in our annual report for the year ended Dec. 31, 2006 for further discussion of credit risk exposures and management thereof.

STATEMENTS OF CASH FLOWS

3 months ended Sept. 30		2007		2006	Explanation of change
Cash and cash equivalents, beginning of period	**$**	**53.1**	$	55.0	
Provided by (used in):					
Operating activities		**155.3**		144.8	In 2007, cash inflows resulted from cash earnings of $161.9 million and cash outflows from working capital of $6.6 million due to timing of collection of PPA revenue partially offset by the timing of accounts payable. In 2006, cash inflows resulted from cash earnings of $130.8 million and positive cash from working capital of $14.0 million
Investing activities		**(166.6)**		(76.1)	In 2007 cash outflows were primarily due to additions to property, plant and equipment of $188.9 million partially offset by proceeds on sale of assets of $16.1 million and positive cash flow from restricted cash of $7.3 million. In 2006, cash outflows were primarily due to additions of property, plant and equipment of $66.2 million, negative cash flow from equity investments of $18.7 million, partially offset by proceeds on the sale of property, plant and equipment of $11.1 million.
Financing activities		**15.4**		(25.2)	In 2007, cash inflows were due to net issuance of long-term debt of $18.7 partially offset by dividends on common shares of $49.6 million, increase of short-term debt of $92.1 million, repurchase of common shares under the NCIB of $26.8 million, and distributions to non-controlling interests of $22.6 million. In 2006, cash outflows were due to repayment of long-term debt of $11.6 million, distributions to subsidiaries' non-controlling interests of $18.0 million, and dividends on common shares of $34.1 million partially offset by an increase in short-term debt of $37.8 million.
Translation of foreign currency cash		**2.6**		0.3	
Cash and cash equivalents, end of period	**$**	**59.8**	$	98.8	

9 months ended Sept. 30		2007		2006	Explanation of change
Cash and cash equivalents, beginning of period	**$**	**65.6**	$	79.3	
Provided by (used in):					
Operating activities		**654.7**		411.9	In 2007, cash inflows were due to a cash earnings of $531.9 million and favorable change in working capital of $122.8 million due to collection of 2006 revenues in 2007 partially offset by the timing of collections of third quarter PPA revenues. In 2006, cash inflows were due to cash earnings of $501.1 million partially offset by $89.2 million of cash used in working capital to build coal inventory at Centralia Coal.
Investing activities		**(320.4)**		(93.1)	In 2007, cash outflows were primarily due to additions of property, plant and equipment of $382.7 million and equity investment of $19.6 million partially offset by proceeds on sale of property, plant and equipment at $39.4 million and reduction in restricted cash of $43.9 million. In 2006, cash outflows were related to capital expenditures of $164.1 million, a decrease in equity investments of $10.5 million offset by realized gains on net investment hedges of $60.7 million and proceeds on sale of assets of $20.3 million.
Financing activities		**(348.5)**		(302.4)	In 2007, cash outflows were due to dividends on common shares of $154.3 million, redemption of preferred securities of $175.0 million, distributions paid to non-controlling interests of $63.1 million, repurchase of common shares under the NCIB of $26.8 and an increase in short-term debt of $59.8 In 2006, the cash used in financing activities increased due to repayment of long-term debt of $283.8 million, payment of distributions to non-controlling interests of $52.1 million, and dividend payments of $100.1 million partially offset by an increase in short-term debt of $124.1 million.
Translation of foreign currency cash		**8.4**		3.1	
Cash and cash equivalents, end of period	**$**	**59.8**	$	98.8	

Operating activities

For the three months ended Sept. 30, 2007, funds generated from operations[1] increased to $155.3 million from $144.8 million for the same period in 2006 due to higher cash earnings of $31.1 million partially offset by negative changes in non-cash working capital of $20.6 million mostly due to the timing of collection of PPA revenues in 2007.

For the nine months ended Sept. 30, 2007, funds generated from operations increased to $654.7 million from $411.9 million due to higher cash earnings as a result of cash being consumed in 2006 to build coal inventory at Centralia Coal and the timing of collection of 2006 receivables in 2007 partially offset by the timing of collection of third quarter 2007 PPA revenues. For the nine months ended Sept. 30, 2007, the corporation paid $24.2 million of costs related to the closure of the Centralia Coal mine.

Investing activities

For the three months ended Sept. 30, 2007, cash used in investing activities was $166.6 million compared to $76.1 million for the same period in 2006. The increase in cash used was mainly due to increased capital spending of $122.7 million partially offset by higher proceeds on sale of equipment of $5.0 million and positive inflows from restricted cash of $6.7 million.

For the nine months ended Sept. 30, 2007, cash used in investing activities was $320.4 million compared to $93.1 million in the same period in 2006 mainly due to higher additions to capital assets in 2007 of $218.6 million and the realization of foreign exchange gains on net investments in the same period in 2006 of $60.7 million partially offset by higher proceeds from the sale of assets of $19.1 million and positive inflows from restricted cash of $44.1 million.

For the three and nine months ended Sept. 30, 2007, the corporation realized no cash outflows from the settlement of net investment hedges of foreign subsidiaries compared to cash outflows of $3.9 million and cash inflows of $60.7 million, respectively, for the same periods in 2006.

In 2007, the corporation has incurred a total of $141.1 million in capital expenditures relating to the Kent Hills, Sundance Unit 4 uprate, and Keephills 3 projects. As well, the corporation has incurred $55.4 million in capital expenditures related to the rail handling and plant modifications at Centralia Coal.

For the nine months ended Sept. 30, 2007, the corporation realized $39.4 million from the sale of assets at our Centralia Mine operation.

Financing activities

For the three months ended Sept. 30, 2007, the corporation generated $15.4 million of cash from financing activities compared to cash outflows of $25.2 million for the same quarter of 2006. This increase in cash generated was mainly due to an increase in short -term debt of $92.1 million partially offset by higher dividends paid of $15.5 million and funds used to purchase shares under the NCIB ($26.8 million).

For the nine months ended Sept. 30, 2007, cash used in financing activities increased $46.1 million, to $348.5 million from $302.4 million, mainly due to the payment of preferred securities in 2007 of $175.0 million, an increase in cash dividends paid and timing of those payments of $54.2 million, and funds used to repurchase common shares under the NCIB program of $26.8 million partially offset by an increase in short and long-term debt ($54.8 million).

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk arises from our ability to meet general funding needs, engage in trading and hedging activities and manage the assets, liabilities and capital structure of the company. Liquidity risk is managed to maintain sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner.

Our liquidity needs are met through a variety of sources, including: cash generated from operations, short-term borrowings against our credit facilities, commercial paper program, and long-term debt issued under the corporation's U.S. shelf registrations and Canadian Medium Term

1 This measure is not defined under Canadian GAAP.

Note program. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling limited partners, and interest and principal payments on debt securities.

We have a $1.5 billion committed syndicated credit facility and approximately $0.4 billion of uncommitted credit facilities. At Sept. 30, 2007, credit utilized under these facilities is comprised of short-term debt of $421.0 million less cash on hand of $59.8 million and letters of credit of $601.2 million.

We have obligations to issue letters of credit to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At Sept. 30, 2007, we had issued letters of credit totaling $601.2 million compared to $633.2 million at Dec. 31, 2006. This decrease in letters of credit is due primarily to lower forward electricity prices in the Pacific Northwest. These letters secure certain amounts included in the corporation's balance sheet under "Risk Management Liabilities" and "Asset Retirement Obligations".

We expect that our ability to generate adequate cash flow from operations in the short-term and the long-term to maintain financial capacity and flexibility to provide for planned growth remains substantially unchanged since Dec. 31, 2006. In the third quarter we received two month's worth of PPA revenue due to timing of contractually scheduled payments. Further, in the fourth quarter a payment relating to 2007 PPA revenues will not be received until Jan. 2, 2008. However, the effect of timing of these payments is that we will receive 12 months of revenue in 2007.

On Oct. 22, 2007, we had approximately 202.2 million common shares outstanding.

At Sept. 30, 2007, the corporation had 1.4 million outstanding employee stock options with a weighted average exercise price of $20.18. For the three months ended Sept. 30, 2007, 0.2 million options with a weighted average exercise price of $22.82 were exercised resulting in 0.2 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $18.86.

For the nine months ended Sept. 30, 2007, 0.6 million options with a weighted average exercise price of $19.70 were exercised resulting in 0.6 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $15.66.

Guarantee contracts

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions using various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Sept. 30, 2007 was a maximum of $2.0 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Sept. 30, 2007, under the limited and unlimited guarantees, was $312.9 million as compared to $285.3 million at Dec. 31, 2006. The liabilities for these amounts are included in the corporation's balance sheet under "Risk Management Liabilities" and "Accounts payable and accrued liabilities".

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Sept. 30, 2007 was a maximum of $1.1 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at Sept. 30, 2007, they are included in accounts payable and accrued liabilities.

The corporation has approximately $0.9 billion of credit available from its committed and uncommitted credit facilities to secure these exposures.

Working capital

For the three months ended Sept. 30, 2007, the negative working capital balance of $6.3 million is due to having only received two month's worth of revenue under our PPAs due to contractual timing of these scheduled payments partially offset by the timing of the payments of accounts payable. On Oct. 2, 2007 we received these payments of $87.3 million, as contractually scheduled, and they will appear in the fourth quarter cash flows.

CLIMATE CHANGE AND THE ENVIRONMENT

The variety of fuels used to generate electricity all have some impact on the environment. While we are pursuing a climate change strategy that includes, among other elements, investing in renewable energy resources such as wind and hydro, we believe that coal and natural gas as fuels will continue to play an important role in meeting the energy needs of the future. Therefore, while we continue to pursue clean coal and other technologies to reduce the impact of our power generating activities upon the environment, changes in current environmental legislation do have, and will continue to have, an impact upon our business. These changes and anticipated changes in the markets in which we operate are discussed below.

Effective July 1, 2007, the Climate Change and Emissions Management Amendment Act was enacted into law in Alberta. Under the legislation, baselines and targets for GHG intensity are set on a facility by facility basis. The legislation requires a 12 per cent reduction in carbon emission intensity over a baseline established as at Dec. 31, 2007. New facilities or those in operation for less than three years are exempt, however, upon the fourth year of operations, the facility baseline is established and gradually reduces by year of operation until the eighth year by which emissions must be 12 per cent below the established baseline. Emissions over the baseline are subject to a charge that must be paid annually. The PPAs for our Alberta based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers. After flow through the net compliance costs are estimated to be approximately $3 million in 2007 and $7 million per year thereafter until we are able to meet the targets for GHG emissions under the Act.

On April 26, 2007, the Canadian government released details of its proposed environmental legislation. The federal plan calls for an 18 per cent reduction in GHG emission intensity starting in 2010, increasing to a 20 per cent absolute reduction requirement by 2020. The proposed legislation also calls for a reduction in air pollutants such as sulphur dioxide, nitrous oxide, mercury, and particulates starting in the 2012 - 2015 period. Proposed reduction caps range from 45 per cent to 60 per cent. A number of material details in the federal plan are still to be determined, including its interaction with provincial programs, which will allow a reasonable determination of future compliance costs.

Both the Saskatchewan and Ontario governments, on June 14 and 18, 2007 respectively, introduced GHG programs. However, neither government provided any details as to how the plans would affect power generation facilities other than Ontario's commitment to close coal units by 2014.

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect July 22, 2007. TransAlta's operations will not be impacted by the bill's performance standards at the current time, provided the facilities do not change ownership or enter into power sales contracts longer than five years. Additionally, further emissions requirements are being considered for our Centralia plant for mercury and nitrous oxide, however final determinations are several months away. Federally, the US Government continues to contemplate a number of proposed greenhouse gas bills but to date no clear outcome or schedule is evident.

Mercury reduction requirements in Alberta are established at a 70 per cent reduction by 2010. TransAlta submitted its mercury control plan in March of 2007. We expect to formalize our investment plan in this new technology in late 2007 or early 2008.

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. As well, we continue to pursue emission offset opportunities that also allow us to meet emission targets at a competitive cost.

OUTLOOK

Current outlook

The key factors affecting the financial results for the remainder of 2007 are the megawatt capacity in place, the availability of and production from generating assets, the margins applicable to non-contracted production, the costs of production, and the margins achieved on Energy Trading activities.

Production, availability and capacity

Generating capacity is expected to increase slightly due to the commencement of full commercial operations of an uprate at Unit 4 of our Sundance coal-fired facility. Production and availability in the fourth quarter is expected to increase compared to the third quarter due to lower planned outages.

Power Prices

For the remainder of 2007, power prices in Alberta are expected to remain strong due to an expected cooler than average winter. Prices in the Pacific Northwest are anticipated to face upside pressure in the fourth quarter due to cooler than normal temperatures. Ontario power prices are forecast to strengthen compared with 2006 because of a tighter supply and a cooler winter.

Approximately 12 per cent of our gas-fired facilities production and two per cent of our coal-fired facilities 2007 annual production have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes 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.

Fuel costs

Mining coal is subject to cost increases due to increased overburden removal, inflation, and diesel commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Alberta coal costs for the remainder of the year are expected to be approximately $5 million higher than compared to the fourth quarter of 2006. Fuel at Centralia Coal is purchased from an external supplier and is expected to be comparable with those seen year to date.

Exposure to gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term gas purchase contracts or corresponding offsets within revenues. Merchant gas facilities are exposed to the changes in spark spreads, as discussed in the Power Prices section. We have not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased coincident with spot pricing.

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 MWh of installed capacity are anticipated in the fourth quarter to be lower compared to those seen to date due to lower planned maintenance activities.

Change in estimate of certain components at Centralia Coal

As a result of stopping mining at the Centralia Coal mine, TransAlta is now procuring all of the coal used in production at the Centralia Coal-fired plant ("Centralia Coal") from several selected third party vendors. The coal that is delivered from these vendors is of a different chemical composition and has a different thermal content than the coal that was delivered from the Centralia Coal mine. Previously, this externally sourced coal was blended with internally produced coal to maximize the output from Centralia Coal. However, with the cessation of mining, this internally produced coal is no longer able to be blended and therefore the coal being consumed is burning at a higher temperature and is producing a different mixture of ash. The boiler and ash handling equipment at Centralia Coal is not currently configured to run optimally at these higher temperatures or to produce the current level of ash.

During the first nine months of 2007, test burns were conducted to determine what equipment modifications needed to be performed to optimize this consumption of third party delivered coal. At the end of the third quarter of 2007, a technical plan was completed including which components needed to be replaced to ensure continued maximum output from Centralia Coal. These equipment modifications are scheduled to occur during planned maintenance outages in 2008 and 2009. As a result, the estimated useful life of the component parts that are to be replaced during these planned outages have been reduced and this change in estimate of useful life will be recognized over the period up to the related maintenance outage.

As a result, depreciation expense will increase over the same comparative periods in 2006 by:

	2007	2008				2009	
	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Increase in depreciation	5.5	5.5	5.5	1.3	1.3	1.3	1.3

Capital expenditures

Our capital expenditures are comprised of spending on sustaining our current operations and for growth activities. The two components are described in greater detail below.

Sustaining expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2007, our estimate for total sustaining capital expenditures, excluding Mexico, is between $350 million and $370 million, allocated among:

- $100 - $105 million for routine capital,
- $75 - $80 million for mining equipment,
- $100 - $105 million for equipment modifications at Centralia Coal and
- $75 - $80 million on planned maintenance as outlined in the following table:

	Coal	Gas and Hydro	**Total**
Capitalized	$ 60 - 65	$ 15 - 20	**$ 75 - 85**
Expensed	$ 50 - 55	$ 0 - 5	**$ 50 - 60**
	$ 110 - 120	$ 15 - 25	**$ 125 - 145**
GWh lost	1,900 - 1,950	125 - 150	**2,025 - 2,100**

In 2007, we expect to lose approximately 2,025 to 2,100 GWh of production due to planned maintenance. During 2007, we have no significant planned maintenance activities at our Mexican operations.

Growth expenditures

For 2007, our growth capital expenditures are estimated to be between $210 million and $220 million on expenses related to the Sundance Unit 4 uprate and the development projects at Keephills 3 and Kent Hills. This amount has decreased compared to the amount estimated at the end of the second quarter due to timing of spending at Keephills 3. Financing for these expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity.

Energy trading

Earnings from our energy trading 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 to maximize earnings while still maintaining an acceptable risk profile. Our objective is for proprietary trading to contribute annually between $50 million and $70 million in gross margin. For the year 2007, we expect to be at the low end of this range.

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 mostly offset foreign currency revenues.

Net interest expense

Net interest expense for the fourth quarter is expected to be higher than seen in the third quarter due to the unwinding of an interest rate swap in the third quarter. However, changes in interest rates and in the value of the Canadian dollar to the U.S. dollar could affect the amount of net interest expense incurred.

Liquidity and capital resources

With the anticipated increased volatility in power and gas markets, market trading opportunities are expected to increase, which can potentially cause the need for additional liquidity. To mitigate this liquidity risk, the corporation maintains a $1.5 billion committed credit facility and monitors exposures to determine any expected liquidity requirements.

RELATED PARTY TRANSACTIONS

In August 2006, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican, a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

For the period November 2002 to November 2012, TA Cogen entered into various transportation swap transactions with a wholly owned subsidiary of TransAlta, TEC. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to Sheerness, which is operated by Canadian Utilities. 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 transaction was 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 with an external third party, therefore TransAlta has no risk other than counterparty risk.

FUTURE ACCOUNTING CHANGES

Capital Disclosures and Financial Instruments – Disclosures and Presentation

On Dec. 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, *Capital Disclosures*, Handbook Section 3862, *Financial Instruments – Disclosures*, and Handbook Section 3863, *Financial Instruments – Presentation*. These new standards will be effective on Jan. 1, 2008.

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. The new Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments — Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The impact of these new standards on our financial statements is currently being assessed.

Inventories

In March 2007, the CICA issued Section 3031, *Inventories*, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards ("IFRS"). This standard will not have a material affect upon TransAlta's financial statements.

International Financial Reporting Standards

In 2005 the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. The AcSB has indicated that Canadian firms will need to begin reporting under IFRS by the first quarter of 2011 with appropriate comparative data from the prior year. Under IFRS, the primary audience is capital markets and as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed.

On July 3, 2007, the Securities and Exchange Commission published for public comment a proposal to eliminate the current requirement that foreign private issuers filing their financial statements using IFRS also file a reconciliation to US GAAP.

The impact of these new standards on our financial statements is currently being assessed.

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 the corporation's 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.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Gross margin	**$ 375.5**	$ 353.9	**$ 1,109.1**	$ 1,087.0
Operating expenses	**(246.7)**	(255.7)	**(751.5)**	(759.1)
Operating income	**128.8**	98.2	**357.6**	327.9
Foreign exchange loss (gain)	**1.1**	3.0	**5.6**	1.2
Net interest expense	**(28.6)**	(47.6)	**(101.6)**	(126.1)
Gain on sale of equipment	**3.4**	-	**15.1**	-
Equity (loss) income	**(3.2)**	(1.4)	**(14.2)**	(0.4)
Earnings before non-controlling interests and income taxes	**101.5**	52.2	**262.5**	202.6
Non-controlling interests	**12.2**	13.2	**34.0**	36.1
Earnings before income taxes	**89.3**	39.0	**228.5**	166.5
Income tax expense (recovery)	**23.4**	3.7	**49.2**	(24.4)
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9

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. Because we believe the turbine impairment charge recorded in the first quarter of 2006 would otherwise affect the comparability of our results from period to period, we have excluded that item, as well as the impact of the tax rate change, to calculate earnings on a comparable basis. We have 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	
	2007	2006	**2007**	2006
Earnings on a comparable basis	**$ 63.6**	$ 35.3	**$ 161.7**	$ 141.8
Sale of assets at Centralia	**2.3**	-	**9.9**	-
Tax rate change	**-**	-	**7.7**	55.3
Turbine impairment, net of tax	**-**	-	**-**	(6.2)
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9
Weighted average common shares outstanding in the period	**202.8**	201.1	**202.6**	200.3
Earnings on a comparable basis per share	**$ 0.32**	$ 0.18	**$ 0.80**	$ 0.71

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

The contractually scheduled payments from the third quarter of 2007 have been included from the calculation of free cash flow as the timing of this payment is dependant upon certain calendar holidays in the month of September and this change due to timing does not occur on a frequent basis. For the nine months ended there is no impact as we received nine months of revenue under the PPAs.

The payment of Centralia mine closure costs have also been excluded as they are one-time in nature. Sustaining capital expenditures is total capital expenditures per the statement of cash flow less $72.7 million we have invested in growth projects in the third quarter of 2007. For the nine months ended Sept. 30, 2007, we have invested $145.3 million 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	
	2007	2006	**2007**	2006
Cash flow from operating activities	**$ 155.3**	$ 144.8	**$ 654.7**	$ 411.9
Add (Deduct):				
Sustaining capital expenditures	**(116.2)**	(55.3)	**(237.4)**	(153.2)
Dividends on common shares	**(49.6)**	(34.1)	**(154.3)**	(100.1)
Distribution to subsidiaries' non-controlling interest	**(22.6)**	(18.0)	**(63.1)**	(52.1)
Non-recourse debt repayments	**(11.2)**	(8.2)	**(32.5)**	(33.7)
Timing of contractualy scheduled payments from the third quarter of 2007	**87.3**	-	**-**	-
Centralia closure costs	**-**	-	**24.2**	-
Cash flows from equity investments	**2.7**	(18.7)	**10.5**	(10.5)
Free cash flow	**$ 45.7**	$ 10.5	**$ 202.1**	$ 62.3

Cash flows from equity investments represent operational cash flow from our equity subsidiaries less sustaining and growth capital expenditures.

SELECTED QUARTERLY INFORMATION

(In millions of Canadian dollars except per share amounts)

	Q4 2006	**Q1 2007** (Restated)	**Q2 2007**	**Q3 2007**
Revenue	**$ 779.8**	**$ 709.9**	**$ 665.5**	**$ 711.6**
Net earnings (loss)	**(146.0)**	**56.2**	**57.2**	**65.9**
Basic earnings (loss) per common share	**(0.72)**	**0.28**	**0.28**	**0.33**
Diluted earnings (loss) per common share	**(0.72)**	**0.28**	**0.28**	**0.33**

	Q4 2005	**Q1 2006**	**Q2 2006**	**Q3 2006**
Revenue	$ 810.1	$ 733.7	$ 599.0	$ 684.0
Net earnings	59.9	69.2	86.4	35.3
Basic earnings per common share	0.30	0.35	0.43	0.18
Diluted earnings per common share	0.30	0.35	0.43	0.18

ADJUSTMENT TO REPORTED FIRST QUARTER RESULTS

Net earnings for the three months ended June 30, 2007 were derived from the net earnings for the six months ended June 30, 2007 and from the adjusted earnings for the three months ended March 31, 2007. The net earnings for the three months ended March 31, 2007 were adjusted to reflect the correction of an error in the previously issued financial statements. Following the release of first quarter earnings, management detected a discrepancy in the amount of unrealized gain recorded on certain contracts that no longer qualified for hedge accounting. The discrepancy arose after implementing an upgrade to our trading system which resulted in some of the contracts that no longer qualify for hedge accounting to be double counted. As a result, the fair values of these additional contracts were incorrectly reclassified from Other Comprehensive Income to the income statement. The net effect of this error was that in the previously issued financial statements for the first quarter net earnings were reduced by $9.8 million, which is net of taxes of $4.0 million. Other comprehensive income for the three months ended March 31, 2007 was increased by a corresponding after-tax amount of $9.8 million. The resulting EPS for the first quarter of 2007 was $0.28 per share, compared to the originally reported $0.33 per share, a further reduction of $0.05 per share. Earnings for the three months ended June 30, 2007 were presented taking account of this correction and earnings for the six months ended June 30, 2007 were not affected. A solution has been implemented which will prevent this situation from arising in the future. In addition, management has added additional controls to this process, including additional management review and oversight.

In coming to the conclusion that the Company's disclosure controls and procedures and the Company's internal control over financial reporting were effective as of June 30, 2007, management considered, among other things, the impact of the above noted error the financial statements and the effectiveness of internal controls in this area. Management has concluded that the control deficiency resulting in this error in previously issued financial statements did not constitute a material weakness in disclosure controls and procedures, or internal control over financial reporting, as of June 30, 2007. In addition, the company has implemented modifications to enhance its internal controls in this area. These changes have not affected, nor are they reasonably likely to materially affect, our internal control over financial reporting.

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934, 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. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have certified that, as of Sept. 30, 2007, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level. These certifications can be found at www.sedar.com.

FORWARD-LOOKING STATEMENTS

This MD&A and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on TransAlta Corporation's beliefs and assumptions based on information available at the time the assumption was made. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. The forward-looking statements relate to, among other things, statements regarding the anticipated business prospects and financial performance of TransAlta. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties and other important factors that could cause the corporation's actual performance to be materially different from those projected, including those material risks and assumptions discussed in this MD&A under the heading 'Outlook' and in the MD&A in our annual report for the year ended Dec. 31, 2006 under the heading 'Risk Factors and Risk Management'. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs associated with environmental compliance, overall costs, cost and availability of fuel to produce electricity, the speed and degree of competition entering the market; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions where TransAlta Corporation operates; results of financing efforts; changes in counterparty risk; and the impact of accounting standards issued by Canadian standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements which is given as of the date it is expressed in this MD&A or otherwise and TransAlta undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

Unaudited	3 months ended Sept. 30 **2007**	2006	9 months ended Sept. 30 **2007**	2006
Revenues *(Note 1)*	**$ 711.6**	$ 656.0	**$ 1,991.8**	$ 1,925.6
Fuel and purchased power *(Note 1)*	**(336.1)**	(302.1)	**(882.7)**	(838.6)
Gross margin	**375.5**	353.9	**1,109.1**	1,087.0
Operations, maintenance and administration	**142.5**	147.2	**437.1**	435.7
Depreciation and amortization *(Note 1)*	**99.5**	103.6	**298.9**	307.4
Taxes, other than income taxes	**4.7**	4.9	**15.5**	16.0
Operating expenses	**246.7**	255.7	**751.5**	759.1
Operating income	**128.8**	98.2	**357.6**	327.9
Foreign exchange gain	**1.1**	3.0	**5.6**	1.2
Gain on sale of equipment *(Note 7)*	**3.4**	-	**15.1**	-
Net interest expense *(Note 6)*	**(28.6)**	(47.6)	**(101.6)**	(126.1)
Equity loss *(Note 8)*	**(3.2)**	(1.4)	**(14.2)**	(0.4)
Earnings before non-controlling interests and income taxes	**101.5**	52.2	**262.5**	202.6
Non-controlling interests	**12.2**	13.2	**34.0**	36.1
Earnings before income taxes	**89.3**	39.0	**228.5**	166.5
Income tax expense (recovery) *(Note 12)*	**23.4**	3.7	**49.2**	(24.4)
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9
Retained earnings				
Opening balance	**722.0**	921.7	**710.0**	866.1
Common share dividends	**(50.6)**	(50.4)	**(152.0)**	(150.4)
Shares cancelled under NCIB *(Note 2)*	**(18.8)**	-	**(18.8)**	-
Closing balance	**$ 718.5**	$ 906.6	**$ 718.5**	$ 906.6
Weighted average number of common shares outstanding in the period	**202.8**	201.1	**202.6**	200.3
Net earnings per share, basic and diluted	**$ 0.33**	$ 0.18	**$ 0.88**	$ 0.95

See accompanying notes

TRANSALTA CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(in millions of Canadian dollars)

Unaudited	**3 months ended Sept. 30, 2007**	3 months ended Sept. 30, 2006	**9 months ended Sept. 30, 2007**	9 months ended Sept. 30, 2006
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9
Other comprehensive loss				
(Losses) gains on translating net assets of self-sustaining foreign operations	**(62.0)**	7.6	**(166.1)**	(36.0)
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations	**66.8**	(3.6)	**190.4**	41.2
Tax recovery	**(12.2)**	-	**(33.5)**	(4.2)
	54.6	(3.6)	**156.9**	37.0
Gains (losses) on translation of self-sustaining foreign operations	**(7.4)**	4.0	**(9.2)**	1.0
Gains (losses) on derivatives designated as cash flow hedges	**139.4**	-	**(105.9)**	-
Tax (recovery) expense	**(51.6)**	-	**30.0**	-
Gains (losses) on derivatives designated as cash flow hedges	**87.8**	-	**(75.9)**	-
Gains on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period	**11.3**	-	**13.3**	-
Tax recovery	**(0.5)**	-	**(5.2)**	-
	10.8	-	**8.1**	-
Other comprehensive income (loss)	**91.2**	4.0	**(77.0)**	1.0
Comprehensive income	**$ 157.1**	$ 39.3	**$ 102.3**	$ 191.9

See accompanying notes

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

Unaudited		**Sept. 30 2007**		Dec. 31 2006
ASSETS				*(Restated, Note 1)*
Current assets				
Cash and cash equivalents	**$**	**59.8**	$	65.6
Accounts receivable		**511.3**		618.3
Prepaid expenses		**17.8**		9.1
Risk management assets *(Notes 1, 3 and 4)*		**128.9**		72.2
Future income tax assets		**42.3**		25.8
Income taxes receivable		**47.1**		47.6
Inventory		**36.8**		53.0
Current portion of other assets *(Note 1)*		**-**		5.4
		844.0		897.0
Restricted cash *(Note 5)*		**261.5**		347.8
Investments *(Note 8)*		**159.9**		154.5
Long-term receivables *(Note 9)*		**31.9**		32.2
Property, plant and equipment				
Cost		**8,457.3**		8,190.1
Accumulated depreciation		**(3,434.0)**		(3,148.2)
		5,023.3		5,041.9
Assets held for sale, net *(Note 7)*		**41.1**		109.8
Goodwill *(Note 10)*		**126.7**		137.5
Intangible assets		**224.1**		292.1
Future income tax assets		**315.2**		294.0
Risk management assets *(Notes 1, 3 and 4)*		**95.1**		65.1
Other assets *(Notes 1 and 4)*		**91.2**		88.2
Total assets	**$**	**7,214.0**	$	7,460.1
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Short-term debt *(Note 3)*	**$**	**421.0**	$	361.9
Accounts payable and accrued liabilities		**461.3**		441.9
Risk management liabilities *(Notes 1, 3 and 4)*		**125.5**		32.4
Income taxes payable		**11.3**		22.3
Future income tax liabilities		**14.0**		19.9
Dividends payable		**49.2**		51.5
Deferred credits and other current liabilities *(Notes 1 and 9)*		**57.4**		48.5
Current portion of long-term debt - recourse *(Notes 3 and 6)*		**321.3**		205.0
Current portion of long-term debt - non-recourse *(Notes 3 and 6)*		**34.1**		44.7
Preferred securities *(Note 6)*		**-**		175.0
		1,495.1		1,403.1
Long-term debt - recourse *(Notes 3 and 6)*		**1,504.2**		1,681.5
Long-term debt - non-recourse *(Notes 3 and 6)*		**227.9**		289.6
Deferred credits and other long-term liabilities *(Notes 1 and 9)*		**342.6**		410.4
Future income tax liabilities		**681.8**		698.6
Risk management liabilities *(Notes 1, 3 and 4)*		**266.3**		14.0
Non-controlling interests		**506.0**		535.0
Common shareholders' equity				
Common shares *(Note 2 and 13)*		**1,790.4**		1,782.4
Retained earnings *(Note 2)*		**718.5**		710.0
Accumulated other comprehensive loss *(Note 2)*		**(318.8)**		(64.5)
Total shareholders' equity		**2,190.1**		2,427.9
Total liabilities and shareholders' equity	**$**	**7,214.0**	$	7,460.1

Contingencies *(Notes 14 and 15)*
Commitments *(Notes 4, 16, and 17)*

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2007**	2006	**2007**	2006
Operating activities				
Net earnings	**$ 65.9**	$ 35.3	**$ 179.3**	$ 190.9
Depreciation and amortization *(Note 10)*	**102.2**	111.5	**302.2**	328.9
Gain on sale of assets *(Note 7)*	**(3.4)**	-	**(15.1)**	-
Non-controlling interests	**12.2**	13.2	**34.0**	36.1
Asset retirement obligation accretion *(Note 9)*	**7.4**	5.5	**19.3**	16.5
Asset retirement costs settled *(Note 9)*	**(16.7)**	(17.2)	**(24.2)**	(19.0)
Future income taxes	**1.6**	(15.8)	**(0.1)**	(53.1)
Unrealized (gains) losses from risk management activities	**(6.7)**	(1.4)	**32.9**	(1.8)
Foreign exchange gain	**(1.1)**	(3.0)	**(5.6)**	(1.2)
Equity loss *(Note 8)*	**3.2**	1.4	**14.2**	0.4
Other non-cash items	**(2.7)**	1.3	**(5.0)**	3.4
	161.9	130.8	**531.9**	501.1
Change in non-cash operating working capital balances	**(6.6)**	14.0	**122.8**	(89.2)
Cash flow from operating activities	**155.3**	144.8	**654.7**	411.9
Investing activities				
Additions to property, plant and equipment	**(188.9)**	(66.2)	**(382.7)**	(164.1)
Proceeds on sale of property, plant and equipment *(Note 7)*	**16.1**	11.1	**39.4**	20.3
Equity investment *(Note 8)*	**(0.5)**	(18.7)	**(19.6)**	(10.5)
Restricted cash *(Note 5)*	**7.3**	0.6	**43.9**	(0.2)
Acquisition of Wailuku Hydro facility	**-**	-	**-**	(1.2)
Realized gains on financial instruments	**-**	(3.9)	**-**	60.7
Proceeds on sale of long-term investments	**-**	-	**-**	3.0
Other	**(0.6)**	1.0	**(1.4)**	(1.1)
Cash flow used in investing activities	**(166.6)**	(76.1)	**(320.4)**	(93.1)
Financing activities				
Increase in short-term debt	**92.1**	37.8	**59.8**	124.1
Net issuance / (repayment) of long-term debt *(Note 6)*	**18.7**	(11.6)	**(5.0)**	(283.8)
Dividends paid on common shares	**(49.6)**	(34.1)	**(154.3)**	(100.1)
Redemption of preferred securities *(Note 6)*	**-**	-	**(175.0)**	-
Funds paid to repurchase common shares under NCIB *(Note 2)*	**(26.8)**	-	**(26.8)**	-
Net proceeds on issuance of common shares *(Note 13)*	**4.3**	2.5	**14.4**	8.5
Distributions to subsidiaries' non-controlling interests	**(22.6)**	(18.0)	**(63.1)**	(52.1)
Other	**(2.0)**	-	**(2.0)**	-
Decrease / (Increase) in advances to TransAlta Power	**1.3**	(1.8)	**3.5**	1.0
Cash flow used in financing activities	**15.4**	(25.2)	**(348.5)**	(302.4)
Cash flow from operating, investing and financing activities	**4.1**	43.5	**(14.2)**	16.4
Effect of translation on foreign currency cash	**2.6**	0.3	**8.4**	3.1
Increase / (decrease) in cash and cash equivalents	**6.7**	43.8	**(5.8)**	19.5
Cash and cash equivalents, beginning of period	**53.1**	55.0	**65.6**	79.3
Cash and cash equivalents, end of period	**$ 59.8**	$ 98.8	**$ 59.8**	$ 98.8
Cash taxes paid	**$ 24.8**	$ (1.0)	**$ 61.8**	$ 23.1
Cash interest paid	**$ 11.6**	$ 24.7	**$ 89.0**	$ 113.4

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 (consisting of normal recurring adjustments and accruals) that are, in the opinion of management, necessary for a fair presentation of the results for the interim periods.

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. Margins are also typically increased in the second quarter due to increased hydro production resulting from spring run-off and rainfall in the Canadian and U.S. markets.

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.

Depreciation Expense

For active mines, accretion expense is included in fuel and purchased power. However, as the Centralia Mine is now considered inactive, accretion expense related to the Centralia Mine is now included as part of depreciation expense. In 2006, $2.1 million was recorded in the third quarter and $6.5 million was recorded for the nine months ended Sept. 30, 2006 in fuel expense related to accretion expense incurred at the Centralia Mine.

Change in estimate of certain components at Centralia Coal

As a result of stopping mining at the Centralia Coal mine, TransAlta is now procuring all of the coal used in production at the Centralia Coal-fired plant ("Centralia Coal") from several selected third party vendors. The coal that is delivered from these vendors is of a different chemical composition and has a different thermal content than the coal that was delivered from the Centralia Coal mine. Previously, this externally sourced coal was blended with internally produced coal to maximize the output from Centralia Coal. However, with the cessation of mining, this internally produced coal is no longer able to be blended and therefore the coal being consumed is burning at a higher temperature and is producing a different mixture of ash. The boiler and ash handling equipment at Centralia Coal is not currently configured to run optimally at these higher temperatures or to produce the current level of ash.

During the first nine months of 2007, test burns were conducted to determine what equipment modifications needed to be performed to optimize this consumption of third party delivered coal. At the end of the third quarter of 2007, a technical plan was completed including which components needed to be replaced to ensure continued maximum output from Centralia Coal. These equipment modifications are scheduled to occur during planned maintenance outages in 2008 and 2009. As a result, the estimated useful life of the component parts that are to be replaced during these planned outages have been reduced and this change in estimate of useful life will be recognized over the period up to the related maintenance outage.

As a result, depreciation expense will increase over the same comparative periods in 2006 by:

	2007	2008				2009	
	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Increase in depreciation	5.5	5.5	5.5	1.3	1.3	1.3	1.3

Presentation of gross margins

Previously, revenues and related costs for contracts settled in real-time physical markets were recorded on a gross basis. However, all of these contracts are being held for trading, irrespective of the market in which they are settled. Therefore, it is more representative of the actual trading activities of Corporate Development and Marketing ("CD&M") to report the results of these contracts on a net basis, consistent with FASB Emerging Issues Task Force (EITF 02-3) "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

Consolidated prior year balances have been reclassified to conform with the current year's presentation, as shown below. Consolidated current year balances have been prepared in the following table using previously disclosed methodologies for information purposes only.

	3 months ended		9 months ended	
	Sept. 30, 2007	Sept. 30, 2006	Sept. 30, 2007	Sept. 30, 2006
Revenue	$ 770.1	$ 684.0	$ 2,145.5	$ 2,016.7
Trading purchases	(58.5)	(28.0)	(153.7)	(91.1)
Net revenue	$ 711.6	$ 656.0	$ 1,991.8	$ 1,925.6

Accounting for Emission Credits and Allowances

Effective July 1, 2007, the Climate Change and Emissions Management Amendment Act was enacted into law in Alberta. The Act establishes a baseline emission by generating unit and emissions over this baseline are subject to a surcharge. Due to the material change in revenue and cost of goods sold as a result of additional carbon compliance costs, TransAlta's accounting policy for emission credits and allowance is described below.

Purchased emission allowances are recorded on the balance sheet at historical cost and are carried at the lower of weighted average cost and net realizable value. Allowances granted to TransAlta or internally generated are recorded at nil. TransAlta records emissions liability on the balance sheet using the best estimate of the amount required to settle our obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, these amounts are recognized as revenue in the period of recovery.

Proprietary trading of emissions allowances that meet the definition of a derivative are accounted for using the fair value method of accounting. Allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

Significant Accounting Policy Changes

Financial Instruments

On Jan. 1, 2007, TransAlta adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1530, *Comprehensive Income*, Section 3855, *Financial Instruments – Recognition and Measurement*, Section 3861, *Financial Instruments – Disclosure and Presentation*, and Section 3865, *Hedges*. We adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income ("AOCI") solely related to accumulated losses on the translation of self-sustaining foreign operations.

Section 3861 outlines disclosure requirements that are designed to enhance financial statement users' understanding of the significance of financial instruments to an entity's financial position, performance and cash flows. The presentation requirements outlined in this Section have been adopted to our financial instruments presentation and related disclosure.

To present comparable 2006 balance sheet figures, prior year balances were reclassified. Short-term and long-term risk management assets were increased by $11.2 million and $43.2 million respectively, and current and long-term portions of other assets were reduced by the corresponding amounts. Short-term and long-term risk management liabilities were increased by $2.1 million and $13.0 million respectively, and current and long-term portions of deferred credits and other long-term liabilities were decreased by the corresponding amounts. $64.5 million of cumulative losses on the translation of self-sustaining foreign subsidiaries was reclassified as the opening balance of AOCI.

Comprehensive Income

Section 1530 introduces comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). OCI represents changes in shareholders' equity during a period arising from transactions and changes in prices, markets, interest rates, and exchange rates and includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, net of hedging activities, and changes in the fair value of the effective portion of cash flow hedging instruments. TransAlta has included in the interim consolidated financial statements consolidated statements of comprehensive income (loss). The cumulative changes in OCI are included in AOCI, which is presented as a new category of shareholders' equity on the consolidated balance sheet.

The majority of the changes were reflected in the value of CD&M risk management assets and liabilities as well as in financial instruments used as hedges of debt and net investment of self-sustaining foreign subsidiaries. The impact of adopting these standards to our Dec. 31, 2006 balance sheet is outlined below:

	Price Risk Assets		Price Risk Liabilities		
	Current	Long-Term	Current	Long-Term	Net
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of CD&M net risk management assets (liabilities) outstanding at Dec. 31, 2006	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

The gross and net of tax impact of adopting these standards to the opening balance of AOCI are outlined below:

Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ 90.9
Fair value of CD&M net risk management liabilities outstanding at Dec. 31, 2006	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	47.7
Total fair value of risk management liabilities	(173.5)
Change in fair value	(264.4)
Tax	(87.1)
Adjustment to opening Accumulated Other Comprehensive loss from fair values	$ (177.3)
Cumulative Translation Adjustment	(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$ (241.8)

Financial Instruments – Recognition and Measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the consolidated balance sheet when the corporation becomes a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value upon initial recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition and amortized using the effective interest rate method. Financial liabilities are removed from the financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability.

Financial assets and financial liabilities held-for-trading are measured at fair value with changes in those fair values recognized in net earnings. Financial assets held-to-maturity, loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market are measured at cost.

Derivative instruments are recorded on the consolidated balance sheet at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net earnings with the exception of the effective portion of (1) derivatives designated as effective cash flow hedges or (2) hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation, which are recognized in OCI.

Section 3855 also provides an entity the option to designate a financial instrument as held-for-trading (the fair value option) on its initial recognition or upon adoption of the standard, even if the financial instrument, other than loans and receivables, was not acquired or incurred principally for the purpose of selling or repurchasing it in the near term. An instrument that is classified as held for-trading by way of this fair value option must have reliable fair values and satisfy one of the following criteria (i) when doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities, or recognizing gains and losses on them on a different basis; or (ii) it belongs to a group of financial assets, financial liabilities or both which are managed and evaluated on a fair value basis in accordance with our risk management strategy, and are reported to senior management personnel on that basis.

Financial assets and liabilities designated as held-for-trading are primarily related to the CD&M segment.

Other significant accounting implications arising upon the adoption of Section 3855 include the use of the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost, and the recognition of the inception fair value of the obligation undertaken in issuing a guarantee that meets the definition of a guarantee pursuant to Accounting Guideline 14, Disclosure of Guarantees (“AcG-14”). No subsequent re-measurement at fair value is required unless the financial guarantee qualifies as a derivative. If the financial guarantee meets the definition of a derivative it is re-measured at fair value at each balance sheet date and reported as a derivative in other assets or other liabilities, as appropriate.

In addition, Section 3855 requires that an entity must select an accounting policy of either expensing debt issue costs as incurred or applying them against the carrying value of the related asset or liability. TransAlta is currently applying all eligible debt transaction costs against the carrying value of the debt.

Hedges

Section 3865 specifies the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for each of the permitted hedging strategies: fair value hedges, cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. When hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified immediately to net earnings when the hedged item is sold or early terminated, or hedged anticipated transaction is probable of not occurring.

In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in net earnings. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a dilution or sale of the net investment; or reduction in equity of the foreign operation as a result of dividend distributions.

Impact upon adoption of Sections 1530, 3855 and 3865

The transition adjustments attributable to the re-measurement of financial assets and financial liabilities at fair value, other than hedging instruments designated as cash flow hedges or hedges of foreign currency exposure of net investment in self-sustaining foreign operations available for sale financial assets, were recognized in opening retained earnings (the value of which was nil) as at Jan. 1, 2007. Adjustments arising from re-measuring financial assets classified as available-for sale at fair value were recognized in opening AOCI as at that date.

For hedging relationships existing prior to adopting Section 3865 that continue to qualify for hedge accounting under the new standard, the transition accounting is as follows: (i) Fair value hedges – any gain or loss on the hedging instrument was recognized in opening retained earnings and the carrying amount of the hedged item was adjusted by the cumulative change in fair value attributable to the designated hedged risk and was also included in opening retained earnings; (ii) Cash flow hedges and hedges of net investments in self-sustaining foreign operations – the effective cumulative portion of any gain or loss on the hedging instrument was recognized in AOCI and the cumulative ineffective portion was included in opening retained earnings (see Note 2).

The following transition adjustments were recorded in our consolidated financial statements: recognition in AOCI of $177.3 million, net of taxes, related to the cumulative losses on the effective portion of our cash flow hedges that are now required to be recognized under Sections 3855 and 3865. In addition, $64.5 million of net foreign currency gains that were previously presented as a separate item in shareholders' equity were reclassified to AOCI. This adjustment was applied retroactively, with restatement, to the statements of other comprehensive income (loss). There was no impact to net earnings or earnings per share of prior periods as a result of adopting these standards.

Variable Interest Entities ("VIEs")

On Sept. 15, 2006, the Emerging Issues Committee issued Abstract No. 163, *Determining the Variability to be Considered in Applying AcG-15* ("EIC-163"). EIC-163 provides additional clarification on how to analyze and consolidate VIEs when transactions take place to reduce the variability in the entity. EIC-163 became effective on Jan. 1, 2007, and its implementation does not have a material impact upon the consolidated financial position or results of operations.

Future accounting changes

Capital Disclosures and Financial Instruments – Disclosures and Presentation

On Dec. 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, *Capital Disclosures*, Handbook Section 3862, *Financial Instruments – Disclosures*, and Handbook Section 3863, *Financial Instruments – Presentation*. These new standards will be effective on Jan. 1, 2008.

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. The new Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments — Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The impact of these new standards on our financial statements is currently being assessed.

Inventories

In March 2007, the CICA issued Section 3031, *Inventories*, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards ("IFRS"). This standard will not have a material affect upon TransAlta's financial statements.

International Financial Reporting Standards

In 2005 the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. The AcSB has indicated that Canadian firms will need to begin reporting under IFRS by the first quarter of 2011 with appropriate comparative data from the prior year. Under IFRS, the primary audience is capital markets and as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed.

On July 3, 2007, the Securities and Exchange Commission published for public comment a proposal to eliminate the current requirement that foreign private issuers filing their financial statements using IFRS also file a reconciliation to US GAAP.

The impact of these new standards on our financial statements is currently being assessed.

2. SHAREHOLDERS' EQUITY

Statement of Shareholders' Equity
(in millions of Canadian dollars except per share amounts)

	Common shares	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders equity
Balance, Dec. 31, 2006 *(Note 1)*	$ 1,782.4	$ 710.0	$ (64.5)	$ 2,427.9
Change in accounting policy (*Note 1*)	-	-	(177.3)	(177.3)
Balance, Dec. 31, 2006, as adjusted	1,782.4	710.0	(241.8)	2,250.6
Net income for the 9 months ended Sept. 30, 2007	-	179.3	-	179.3
Common shares issued (dividends declared)	16.0	(152.0)	-	(136.0)
Shares purchased under NCIB	(8.0)	(18.8)	-	(26.8)
Unrealized gains and losses on translating financial statements of self-sustaining foreign operations	-	-	(9.2)	(9.2)
Gains and losses on derivatives designated as cash flow hedges	-	-	(75.9)	(75.9)
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net income in the current period	-	-	8.1	8.1
Balance, Sept. 30, 2007	**$ 1,790.4**	**$ 718.5**	**$ (318.8)**	**$ 2,190.1**

Normal course issuer bid ("NCIB") program

On Sept. 11, 2007, TransAlta announced an expansion to its NCIB program. The company may purchase, for cancellation, up to 20.2 million of its common shares or approximately 10 per cent of the 202.0 million common shares issued and outstanding as at April 23, 2007. The NCIB program started on May 3, 2007 and will continue until May 2, 2008. Purchases will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the three and nine months ended Sept. 30, 2007, TransAlta purchased 903,600 shares at an average price of $29.65 per share. The units were purchased for an amount higher than their weighted average book value per share ($8.83 per share) resulting in a reduction of retained earnings of $18.8 million.

	9 months ended Sept. 30, 2007
Total shares purchased (in millions)	0.9
Average purchase price per share	$ 29.65
Total cash paid (in millions)	$ 26.8
Weighted average book value of shares cancelled	8.0
Reduction to retained earnings (in millions)	$ 18.8

3. FAIR VALUES 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, willing parties who are under no compulsion to act. Fair values are determined by reference to prices in active markets for that instrument to which we have access. In the absence of an active market, we determine fair values based on valuation models, such as option pricing models and discounted cash flow analysis, using observable market-based inputs.

Fair values determined using valuation models require the use of assumptions concerning the amount and timing of estimated future cash flows. In determining those assumptions, the corporation looks primarily to external readily observable market inputs including factors such as electricity prices, gas prices, and anticipated market growth. In limited circumstances, the corporation uses input parameters that are not based on observable market data and believes that using possible alternative assumptions will not result in significantly different fair values.

(a) Accounting for changes in fair value of financial instruments during the period

As described in Note 1, financial instruments classified as held-for trading are carried at fair value on the consolidated balance sheet. Any changes in the fair values of financial instruments classified as held-for-trading are recognized in net earnings except those contracts that are part of effective hedge relationships.

Carrying value and Fair value of selected Financial Instruments

While most financial assets and liabilities are carried at fair value, the following table provides a comparison of carrying values to fair values as at Sept. 30, 2007, and Dec. 31, 2006, for selected financial instruments:

Carrying value and fair value of financial instruments as at Sept. 30, 2007

	Classified as held-for-trading	Per Consolidated Balance Sheet	Total Fair Value
Risk management assets			
- Current	$ 128.9	$ 128.9	$ 128.9
- Long Term	95.1	95.1	95.1
Total risk management assets	$ 224.0	$ 224.0	$ 224.0
Risk management liabilities			
- Current	$ 125.5	$ 125.5	$ 125.5
- Long Term	266.3	266.3	266.3
Total risk management liabilities	$ 391.8	$ 391.8	$ 391.8

TransAlta adopted Sections 1530, 3855, and 3865 retroactively with an adjustment of opening AOCI effective Jan. 1, 2007.

Carrying value and fair value of financial instruments as at Dec. 31, 2006

	Classified as held-for-trading	Total Carrying Value	Per Consolidated Balance Sheet	Total Fair Value [1]
Risk management assets				
- Current	$ 72.2	$ 72.2	$ 72.2	$ 112.2
- Long Term	65.1	65.1	65.1	138.8
Total risk management assets	$ 137.3	$ 137.3	$ 137.3	$ 251.0
Risk management liabilities				
- Current	$ 32.4	$ 32.4	$ 32.4	$ 126.1
- Long Term	14.0	14.0	14.0	298.4
Total risk management liabilities	$ 46.4	$ 46.4	$ 46.4	$ 424.5

[1] *Differences between fair value and carrying value are a result of cash flow hedges that were not previously recorded, but have been accounted for under Section 3865*

(b) Hedging activities

Derivative and non-derivative financial instruments are used to manage exposures to interest, commodity prices, currency, credit, and other market risks. When derivatives are used to manage the corporation's own exposures, the corporation determines for each derivative whether hedge accounting can be applied. Where hedge accounting can be applied, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposure of a net investment in a self-sustaining foreign operation. The derivative must be highly effective in accomplishing the objective of offsetting either changes in the fair value or cash flows attributable to the hedged risk both at inception and over the life of the hedge. If it is determined that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

Fair value hedges

Interest rate swaps are used to hedge exposures to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates. Foreign exchange contracts are also used to hedge foreign currency denominated assets and liabilities. See Note 6 for a further description of the terms and rates of these swaps.

For the three and nine months ended Sept. 30, 2007, the ineffective portion of fair value hedges recognized in interest expense amounted to a pre-tax unrealized loss of $nil.

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, 2007, a pre-tax unrealized gain of $139.4 million was recorded in OCI for the effective portion of the cash flow hedges, and an unrealized gain of $11.4 million was reclassified to net income. For the nine months ended Sept. 30, 2007, a pre-tax unrealized loss of $105.9 million was recorded in OCI for the effective portion of the cash flow hedges, and an unrealized gain of $13.3 million was reclassified to net income. A net unrealized loss of $nil was recognized in income for the ineffective portion.

At Sept. 30, 2006, the corporation's cash flow hedges of the forecasted sales and the forecasted purchases for the corporation's generating facilities resulted in the recognition of an after-tax unrealized gain in OCI of $142.4 million.

Over the next 12 months, the corporation estimates that $36.0 million of after-tax losses will be reclassified from AOCI to OCI. These estimates assume constant gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings, either positive or negative, will be for the next 12 months.

Net investment hedges

Foreign exchange contracts and foreign currency-denominated liabilities are used to manage our foreign currency exposures to net investments in self-sustaining foreign operations having a functional currency other than the Canadian dollar. Foreign denominated expenses are also used to assist in managing foreign currency exposures on earnings from self-sustaining foreign operations.

For the three months ended Sept. 30, 2007, the net loss of $7.4 million (Sept. 30, 2006 - $4.0 million gain), and for the nine months ended Sept. 30, 2007, the net loss of $9.2 million (Sept. 30, 2006 - $1.0 million gain) relating to the net investment in foreign operations was recognized in OCI.

The following table presents the fair values of derivative instruments categorized by their hedging relationships, as well as derivatives that are not designated in hedging relationships.

Fair value of derivative instruments as at Sept. 30, 2007

(in thousands of dollars)	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated in a hedging relationship	**Total**
Financial Assets					
Derivative instruments	$ 9.5	$ 5.9	$ 166.1	$ 42.5	**$ 224.0**
Financial Liabilities					
Derivative instruments	$ (5.3)	$ (336.5)	$ (0.9)	$ (49.1)	**$ (391.8)**

US dollar denominated debt with a face value of $600 million USD has been designated as a part of the hedge of TransAlta's self-sustaining foreign operations.

4. RISK MANAGEMENT ASSETS AND LIABILITIES

Risk management assets and liabilities are comprised of two major types: (1) those that are used in the CD&M and Generation segments in relation to trading activities and certain contracting activities and (2) those used in hedging non-energy trading transactions, debt, and the net investment in self-sustaining foreign subsidiaries.

The overall balances reported in risk management assets and liabilities are shown below:

Balance Sheet - Totals	Sept. 30, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	$ 41.4	$ 87.5	$ 128.9	$ 61.0	$ 11.2	$ 72.2
- Long-term	0.6	94.5	95.1	21.9	43.2	65.1
Risk management liabilities						
- Current	(108.2)	(17.3)	(125.5)	(30.3)	(2.1)	(32.4)
- Long-term	(243.9)	(22.4)	(266.3)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	$ (310.1)	$ 142.3	$ (167.8)	$ 51.6	$ 39.3	$ 90.9

Energy Trading

The hedge and non-hedge values of other risk management assets and liabilities for energy trading are included on the consolidated balance sheets as follows:

Balance Sheet - Energy Trading		**Sept. 30, 2007**		Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to energy trading
Risk management assets				
- Current	**$ 4.2**	**$ 37.2**	**$ 41.4**	$ 61.0
- Long-term	**(1.8)**	**2.4**	**0.6**	21.9
Risk management liabilities				
- Current	**(77.6)**	**(30.6)**	**(108.2)**	(30.3)
- Long-term	**(243.1)**	**(0.8)**	**(243.9)**	(1.0)
Net risk management assets (liabilities) outstanding	**$ (318.3)**	**$ 8.2**	**$ (310.1)**	$ 51.6

The following table illustrates the impact of adopting new standards for financial instruments and the movements in 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, 2007:

	Hedges		Non-Hedges		
Change in fair value of net assets (liabilities)	**Fair value (Market)**	**Fair value (Model)**	**Fair value (Market)**	**Fair value (Model)**	**Total**
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	**$ 51.6**
Net risk management liabilities outstanding at Dec. 31, 2006 - *fair value* [1]	(253.0)	(19.8)	52.7	(1.1)	**(221.2)**
Contracts realized, amortized or settled during the period	23.8	2.7	(30.2)	(2.6)	**(6.3)**
Changes in values attributable to market price and other market changes	(52.7)	(8.8)	5.5	(1.9)	**(57.9)**
New contracts entered into during the current period	(9.6)	-	(6.3)	5.6	**(10.3)**
Changes in foreign exchange values	(18.2)	-	3.7	0.1	**(14.4)**
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	-	(17.3)	-	**-**
Net risk management assets (liabilities) outstanding at Sept. 30, 2007 - *fair value*	**$ (292.4)**	**$ (25.9)**	**$ 8.1**	**$ 0.1**	**$ (310.1)**

[1] *As a result of adopting new accounting standards*

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

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

		2007	**2008**	**2009**	**2010**	**2011**	**2012 and thereafter**	**Total**
Hedges	Fair value based on market prices	$ (8.7)	$ (100.7)	$ (110.0)	$ (59.4)	$ (12.0)	$ (1.6)	**$ (292.4)**
	Fair value based on models	(1.4)	(6.5)	(8.2)	(7.4)	(2.4)	-	**$ (25.9)**
		$ (10.1)	**$ (107.2)**	**$ (118.2)**	**$ (66.8)**	**$ (14.4)**	**$ (1.6)**	**$ (318.3)**
Non-Hedges	Fair value based on market prices	$ 3.5	$ 4.4	$ 0.2	$ -	$ -	$ -	**$ 8.1**
	Fair value based on models	(1.3)	1.3	0.1	-	-	-	**$ 0.1**
		$ 2.2	**$ 5.7**	**$ 0.3**	**$ -**	**$ -**	**$ -**	**$ 8.2**
Grand total		**$ (7.9)**	**$ (101.5)**	**$ (117.9)**	**$ (66.8)**	**$ (14.4)**	**$ (1.6)**	**$ (310.1)**

The corporations fixed price proprietary trading positions at Sept. 30, 2007 and Dec. 31, 2006, were as follows:

Units (000s)	Electricity (MWh)	Natural Gas (GJ)	Transmission (MWh)	Coal (Tonnes)	Emissions (Tonnes)
Fixed price payor, notional amounts, Sept. 30, 2007	**19,836**	**87,984**	**1,854**	**713**	**4**
Fixed price payor, notional amounts, Dec. 31, 2006	13,944	20,289	1,479	-	-
Fixed price receiver, notional amounts, Sept. 30, 2007	**19,572**	**98,143**	-	**728**	**17**
Fixed price receiver, notional amounts, Dec. 31, 2006	21,536	26,231	-	-	-
Maximum term in months, Sept. 30, 2007	**24**	**13**	**79**	**26**	**2**
Maximum term in months, Dec. 31, 2006	33	16	24	-	-

Other Risk Management Assets and Liabilities

The hedge and non-hedge values of non-energy trading assets and liabilities included on the consolidated balance sheets are as follows:

Balance Sheet - Other	Sept. 30, 2007			Dec. 31, 2006
	Hedges	Non-Hedges	Total	Total related to non-energy trading
Risk management assets				
- Current	**$ 84.6**	**$ 2.9**	**$ 87.5**	$ 11.2
- Long-term	**94.5**	**-**	**94.5**	43.2
Risk management liabilities				
- Current	**(15.7)**	**(1.6)**	**(17.3)**	(2.1)
- Long-term	**(6.4)**	**(16.0)**	**(22.4)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 157.0**	**$ (14.7)**	**$ 142.3**	$ 39.3

The following table illustrates the impact of adopting new standards for financial instruments and the movements in the fair value of the corporation's other net risk management assets and liabilities separately by source of valuation during the nine months ended Sept. 30, 2007:

	Hedges	Non-Hedges	Total
Net other risk management assets (liabilities) at Dec. 31, 2006 - *as reported*	$ 50.1	$ (10.8)	$ 39.3
Net other risk management assets (liabilities) at Dec. 31, 2006 - *fair value* [1]	58.0	(10.3)	47.7
Contracts realized, amortized or settled during the period	(5.7)	(0.1)	(5.8)
Changes in values attributable to market price and other market changes	91.8	(4.6)	87.2
New contracts entered into during the current period	12.9	0.3	13.2
Net other risk management assets (liabilities) outstanding at Sept. 30, 2007 - *fair value*	$ 157.0	$ (14.7)	$ 142.3

[1] *As a result of adopting new accounting standards*

Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent 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, change in ownership of the foreign operation, or financial instrument being hedged.

5. RESTRICTED CASH

Restricted cash is primarily comprised of an investment in Notes held in trust as security for a subsidiary's obligation under a credit derivative agreement. Should the subsidiary fail to perform its obligations under this agreement, the counterparty has the right to retain the Notes in satisfaction of the subsidiary's obligation. The Notes earn interest at six month LIBOR and mature in 2016.

The change in restricted cash is outlined below:

Balance, Dec. 31, 2006	$ 347.8
Change in foreign exchange rates	(42.4)
Amount returned to TransAlta	(43.9)
Balance, Sept. 30, 2007	$ 261.5

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Amounts outstanding	**Sept. 30, 2007**			Dec. 31, 2006		
	Fair Value [1]	**Cost**	**Interest [2]**	Fair Value	Cost	Interest [2]
Debentures, due 2007 to 2033	**$ 1,155.6**	**$ 1,146.1**	**6.1%**	$ 1,161.3	$ 1,146.4	6.1%
Senior Notes, US$600.0 million	**595.5**	**600.8**	**6.3%**	683.6	693.2	6.3%
Non-recourse debt	**262.1**	**262.1**	**7.7%**	334.3	334.3	7.7%
Notes payable - Windsor plant, due 2007 to 20	**43.6**	**43.6**	**7.4%**	46.9	46.9	7.4%
Commercial Loan Obligation	**30.7**	**30.7**	**5.7%**	-	-	**-**
Preferred securities, due in 2050	**-**	**-**	**-**	175.0	175.0	7.8%
	2,087.5	**2,083.3**		2,401.1	2,395.8	
Less: current portion	**(355.4)**	**(355.4)**		(424.7)	(424.7)	
	$ 1,732.1	**$ 1,727.9**		$ 1,976.4	$ 1,971.1	

[1] *Fair value debentures and notes currently being utilized as Net Investment Hedge.*

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

The corporation has converted fixed interest rate debt with rates ranging from 5.75 per cent to 6.90 per cent to floating rates through the use of receive fixed pay floating interest rate swaps. The interest rate swaps have maturities ranging from 2011 to 2013.

On Jan. 2, 2007, the corporation redeemed its Preferred Securities which had an aggregate principal of $175.0 million. As at Dec. 31, 2006 the Preferred Securities were presented as a liability on the consolidated balance sheets. Distributions on these Preferred Securities are included in interest expense as shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Interest on long-term debt	**$ 35.6**	$ 41.1	**$ 111.0**	$ 109.9
Interest on short-term debt	**6.4**	4.1	**18.9**	10.3
Interest on preferred securities	**-**	3.4	**-**	10.2
Interest income	**(11.8)**	(1.0)	**(26.1)**	(4.3)
Capitalized interest	**(1.6)**	-	**(2.2)**	-
Net interest expense	**$ 28.6**	$ 47.6	**$ 101.6**	$ 126.1

The corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2007 relates to the corporation's investment in Keephills 3 and Kent Hills.

7. ASSETS HELD FOR SALE

As a result of the decision to stop mining at Centralia, all associated mining and reclamation equipment is being held for sale. All equipment has been recorded at the lower of net book value or anticipated realized proceeds. These assets are included in the Generation segment. During the second quarter some of this equipment had been retained for reclamation activities ($20.2 million), transferred to the Highvale mine for use in production of coal inventory ($8.6 million), and allocated to potential future Westfields Development ($16.7 million) and has been reclassified to property, plant, and equipment. The decision to retain equipment for use in reclamation activities at the Centralia Mine and in operations at the Highvale Mine was arrived at as the economics of retaining these assets was greater than the potential cash proceeds from disposing these assets.

During the third quarter of 2007, equipment with a net book value of $12.7 million was sold for proceeds of $16.1 million; the remainder of these assets are anticipated to be sold in 2007. For the nine months ended Sept. 30, 2007, equipment with a book value of $24.3 million was sold for proceeds of $39.4 million.

In 2006 we sold excess turbines in inventory for net proceeds of $11.1 million, for the three months ended Sept. 30, 2006, and net proceeds of $20.3 for the nine months ended Sept. 30, 2006, which equaled their net book value.

8. INVESTMENTS

Investments mainly represent our investment in our Mexican operations. As required under Accounting Guideline 15, Consolidation of Variable Interest Entities, of the Canadian Institute of Chartered Accountants ("CICA"), our Mexican operations are accounted for as equity subsidiaries. However, these plants are owned by TransAlta and managed as part of the Generation segment. The table below summarizes key information from these operations.

The change in investments is shown below:

Opening balance, Dec. 31, 2006	$	154.5
Repayment of debt by Mexican operations		19.6
Equity losses		(14.2)
Closing balance, Sept. 30, 2007	$	159.9

9. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

		Sept. 30, 2007		Dec. 31, 2006
Asset retirement obligation	**$**	**304.2**	$	328.5
Deferred revenues and other		**20.7**		19.7
Power purchase arrangement in limited partnership		**25.4**		27.1
Accrued benefit liability		**49.7**		58.0
Centralia mine closure costs		**-**		25.6
	$	**400.0**	$	458.9
Less: current portion		**(57.4)**		(48.5)
	$	**342.6**	$	410.4

For the nine months ended Sept. 30, 2007, the corporation paid $24.2 million of costs related to the closure of the Centralia Coal mine. The difference between actual cash payments and the balance as at Dec. 31, 2006 is due to the strengthening of the Canadian dollar relative to the US dollar.

The reconciliation between the opening and closing asset retirement obligation balances is provided below:

Balance, Dec. 31, 2006	$	328.5
Liabilities incurred in period		2.4
Liabilities settled in period		(24.2)
Accretion expense		19.3
Revisions in estimated cash flows		(1.0)
Change in foreign exchange rates		(20.8)
Balance, Sept. 30, 2007	**$**	**304.2**

The amount of any asset retirement obligations due beyond one year are included in deferred credits and other long-term liabilities on the consolidated balance sheets. Any amount anticipated to be settled in the next 12 months is included in the current portion of deferred credits and long term liabilities on the consolidated balance sheets.

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

10. SEGMENTED DISCLOSURES

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

3 months ended Sept. 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Revenues *(Note 1)*	**$ 696.2**	**$ 15.4**	**$ -**	**$ 711.6**
Fuel and purchased power *(Note 1)*	**(336.1)**	**-**	**-**	**(336.1)**
Gross margin	**360.1**	**15.4**	**-**	**375.5**
Operations, maintenance and administration	**108.2**	**9.7**	**24.6**	**142.5**
Depreciation and amortization	**96.0**	**0.4**	**3.1**	**99.5**
Taxes, other than income taxes	**4.6**	**-**	**0.1**	**4.7**
Intersegment cost allocation	**6.8**	**(6.8)**	**-**	**-**
Operating expenses	**215.6**	**3.3**	**27.8**	**246.7**
Operating income (loss)	**$ 144.5**	**$ 12.1**	**$ (27.8)**	**$ 128.8**
Gain on sale of equipment				**3.4**
Foreign exchange gain				**1.1**
Net interest expense				**(28.6)**
Equity loss				**(3.2)**
Earnings before income taxes and non-controlling interests				**$ 101.5**

3 months ended Sept. 30, 2006	Generation	CD&M	Corporate	Total
Revenues *(Note 1)*	$ 635.6	$ 20.4	$ -	$ 656.0
Fuel and purchased power	(302.1)	-	-	(302.1)
Gross margin	333.5	20.4	-	353.9
Operations, maintenance and administration	119.4	8.8	19.0	147.2
Depreciation and amortization	100.0	0.3	3.3	103.6
Taxes, other than income taxes	4.9	-	-	4.9
Intersegment cost allocation	7.1	(7.1)	-	-
Operating expenses	231.4	2.0	22.3	255.7
Operating income (loss)	$ 102.1	$ 18.4	$ (22.3)	$ 98.2
Foreign exchange gain				3.0
Net interest expense				(47.6)
Equity loss				(1.4)
Earnings before income taxes and non-controlling interests				$ 52.2

9 months ended September 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Revenues *(Note 1)*	**$ 1,949.4**	**$ 42.4**	**$ -**	**$ 1,991.8**
Fuel and purchased power *(Note 1)*	**(882.7)**	**-**	**-**	**(882.7)**
Gross margin	**1,066.7**	**42.4**	**-**	**1,109.1**
Operations, maintenance and administration	**340.9**	**26.6**	**69.6**	**437.1**
Depreciation and amortization	**288.3**	**1.1**	**9.5**	**298.9**
Taxes, other than income taxes	**15.3**	**-**	**0.2**	**15.5**
Intersegment cost allocation	**20.5**	**(20.5)**	**-**	**-**
Operating expenses	**665.0**	**7.2**	**79.3**	**751.5**
Operating income (loss)	**$ 401.7**	**$ 35.2**	**$ (79.3)**	**$ 357.6**
Gain on sale of equipment				**15.1**
Foreign exchange gain				**5.6**
Net interest expense				**(101.6)**
Equity loss				**(14.2)**
Earnings before income taxes and non-controlling interests				**$ 262.5**

9 months ended Sept. 30, 2006	Generation	CD&M	Corporate	Total
Revenues *(Note 1)*	$ 1,870.2	$ 55.4	$ -	$ 1,925.6
Fuel and purchased power	(838.6)	-	-	(838.6)
Gross margin	1,031.6	55.4	-	1,087.0
Operations, maintenance and administration	352.6	25.2	57.9	435.7
Depreciation and amortization	296.9	1.0	9.5	307.4
Taxes, other than income taxes	16.0	-	-	16.0
Intersegment cost allocation	21.0	(21.0)	-	-
Operating expenses	686.5	5.2	67.4	759.1
Operating income (loss)	$ 345.1	$ 50.2	$ (67.4)	$ 327.9
Foreign exchange gain				1.2
Net interest expense				(126.1)
Equity loss				(0.4)
Earnings before income taxes and non-controlling interests				$ 202.6

II. Selected balance sheet information

Sept. 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Goodwill	**$ 97.2**	**$ 29.5**	**$ -**	**$ 126.7**
Total segment assets	**$ 5,724.6**	**$ 190.9**	**$ 1,298.5**	**$ 7,214.0**

Dec. 31, 2006				
Goodwill	$ 108.0	$ 29.5	$ -	$ 137.5
Total segment assets	$ 6,159.3	$ 185.0	$ 1,115.8	$ 7,460.1

For the nine months ended Sept. 30, 2007, goodwill decreased $10.8 million compared to Dec. 31, 2006 due to the strengthening of the Canadian dollar on goodwill denominated in US dollars related to CE Generation LLC ("CE Gen").

III. Selected cash flow information

3 months ended Sept. 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Capital expenditures	**$ 183.2**	**$ 1.0**	**$ 4.7**	**$ 188.9**

3 months ended Sept. 30, 2006				
Capital expenditures	$ 63.4	$ -	$ 2.8	$ 66.2

9 months ended Sept. 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Capital expenditures	**$ 368.2**	**$ 2.5**	**$ 12.0**	**$ 382.7**

9 months ended Sept. 30, 2006				
Capital expenditures	$ 150.5	$ 1.6	$ 12.0	$ 164.1

Depreciation and amortization expense per statement of cash flows

The reconciliation between depreciation expense on the income statement and statement of cash flows is presented below:

IV. Reconciliation

	3 months ended Sept. 30		9 months ended Sept. 30	
	2007	2006	**2007**	2006
Depreciation and amortization expense for reportable segments	**$ 99.5**	$ 103.6	**$ 298.9**	$ 307.4
Mining equipment depreciation, included in fuel and purchased power	**6.6**	14.2	**20.3**	43.0
Accretion expense, included in depreciation and amortization expense	**(7.4)**	(5.5)	**(19.3)**	(16.5)
Other	**3.5**	(0.8)	**2.3**	(5.0)
Depreciation and amortization expense per statements of cash flows	**$ 102.2**	$ 111.5	**$ 302.2**	$ 328.9

11. EMPLOYEE FUTURE BENEFITS

The corporation has registered pension plans in Canada, Mexico and the U.S. covering substantially all employees of the corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada, there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plans has been closed for new employees for all periods presented. Costs recognized in the period are presented below:

3 months ended Sept. 30, 2007	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 1.0**	**$ 0.5**	**$ 0.4**	**$ 1.9**
Interest cost	**4.4**	**0.7**	**0.3**	**5.4**
Expected return on plan assets	**(6.8)**	**-**	**-**	**(6.8)**
Experience loss	**0.8**	**1.0**	**0.2**	**2.0**
Past service costs	**-**	**(0.1)**	**-**	**(0.1)**
Amortization of net transition asset	**(2.2)**	**-**	**-**	**(2.2)**
Curtailment	**-**	**-**	**0.1**	**0.1**
Settlement	**0.2**	**-**	**-**	**0.2**
Defined benefit (income) expense	**(2.6)**	**2.1**	**1.0**	**0.5**
Defined contribution option expense of registered pension plan	**3.2**	**-**	**-**	**3.2**
Net expense	**$ 0.6**	**$ 2.1**	**$ 1.0**	**$ 3.7**

3 months ended Sept. 30, 2006	Registered	Supplemental	Other	Total
Current service cost	$ 1.2	$ 0.3	$ 0.4	$ 1.9
Interest cost	4.8	0.6	0.1	5.5
Expected return on plan assets	(6.3)	-	-	(6.3)
Experience loss	0.6	0.2	0.1	0.9
Past service costs	-	(0.1)	0.1	-
Amortization of net transition asset	(2.3)	-	-	(2.3)
Defined benefit (income) expense	(2.0)	1.0	0.7	(0.3)
Defined contribution option expense of registered pension plan	4.1	-	-	4.1
Net expense	$ 2.1	$ 1.0	$ 0.7	$ 3.8

9 months ended Sept. 30, 2007	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 2.9**	**$ 1.1**	**$ 1.1**	**$ 5.1**
Interest cost	**14.5**	**1.8**	**0.9**	**17.2**
Expected return on plan assets	**(19.1)**	**-**	**-**	**(19.1)**
Experience loss	**0.9**	**1.2**	**0.3**	**2.4**
Past service costs	**0.1**	**(0.2)**	**0.1**	**-**
Amortization of net transition (asset) obligation	**(6.8)**	**0.2**	**-**	**(6.6)**
Curtailment	**-**	**-**	**0.3**	**0.3**
Settlement	**0.4**	**-**	**-**	**0.4**
Defined benefit (income) expense	**(7.1)**	**4.1**	**2.7**	**(0.3)**
Defined contribution option expense of registered pension plan	**12.6**	**-**	**-**	**12.6**
Net expense	**$ 5.5**	**$ 4.1**	**$ 2.7**	**$ 12.3**

9 months ended Sept. 30, 2006	Registered	Supplemental	Other	Total
Current service cost	$ 3.5	$ 0.9	$ 1.1	$ 5.5
Interest cost	14.8	1.6	0.8	17.2
Expected return on plan assets	(19.0)	-	-	(19.0)
Experience loss	2.1	0.7	0.3	3.1
Past service costs	0.1	(0.2)	0.2	0.1
Amortization of net transition (asset) obligation	(6.9)	0.2	-	(6.7)
Defined benefit (income) expense	(5.4)	3.2	2.4	0.2
Defined contribution option expense of registered pension plan	13.8	-	-	13.8
Net expense	$ 8.4	$ 3.2	$ 2.4	$ 14.0

12. INCOME TAXES

As a result of the Tax Fairness Plan, Canadian corporate tax rates were reduced by 0.5 per cent beginning in 2011, resulting in a reduction of tax expense in the second quarter of 2007 of $7.7 million reflecting the impact of these changes on prior years' earnings.

In 2006, as a result of Alberta and Federal budgets, comparable tax rates were reduced resulting in a reduction of tax expense of $55.3 million reflecting the impact of these changes on prior years' earnings.

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, 2007, the corporation had 202.2 million (Dec. 31, 2006 – 202.4 million) common shares issued and outstanding. During the three and nine months ended Sept. 30, 2007, 0.2 million (2006 – 0.9 million) and 0.7 million (2006 – 2.8 million) shares, respectively, were issued for proceeds of $4.3 million (2006 – $2.5 million) and $14.4 million (2006 – $8.5 million), respectively.

During the third quarter of 2007, 0.9 million shares were cancelled under the NCIB program.

B. Stock options

At Sept. 30, 2007, the corporation had 1.4 million outstanding employee stock options (Dec. 31, 2006 – 2.2 million). For the three months ended Sept. 30, 2007, 0.2 million options with a weighted average exercise price of $22.82 were exercised resulting in 0.2 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $18.86.

For the nine months ended Sept. 30, 2007, 0.6 million options with a weighted average exercise price of $19.70 were exercised resulting in 0.6 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $15.66.

14. 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 will have a material adverse effect on the corporation, taken as a whole.

15. PRIOR PERIOD REGULATORY DECISION

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the Federal Power Act ("FPA"), Federal Energy Regulatory Commission ("FERC") established a claim of approximately US$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange ("PX") and the California Independent System Operator ("ISO") during the Oct. 2, 2000 through June 20, 2001 period (the "Main Refund Transactions"). TransAlta has provided US$46 million to account for refund liabilities relating to Main Refund Transactions.

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006 TransAlta filed for rehearing of FERC's rejection. On August 24, 2007, the US Court of Appeals for the Ninth Circuit granted the appeal. The parties have until November 16, 2007 to decide if they seek a rehearing or remand the case to FERC.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (the "Summer Transactions"). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources ("CDWR") referred to as CERS (the "CERS Transactions"). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

16. GUARANTEES

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Sept. 30, 2007 was a maximum of $2.0 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at Sept. 30, 2007, under the limited and unlimited guarantees, was $312.9 million as compared to $285.3 million at Dec. 31, 2006. The liabilities for these amounts are included in the corporation's balance sheet under "Risk Management Liabilities" and "Accounts payable and accrued liabilities".

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Sept. 30, 2007 was a maximum of $1.1 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at Sept. 30, 2007, they are included in accounts payable and accrued liabilities.

A subsidiary of the corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include US$255.0 million of loans made to subsidiaries of the corporation.

The corporation has approximately $0.9 billion of credit available from its committed and uncommitted credit facilities to secure these exposures.

17. COMMITMENTS

On June 21, 2007, TransAlta Utilities Corporation, a subsidiary of the corporation, has entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal to the Keephills 3 joint venture project. The total dragline purchase costs include approximately $104 million USD for the purchase of the equipment, and an additional $29 million CAD for the assembly and commissioning of the dragline, for a total of approximately $150 million CAD, with final payments for goods and services due by May 2010. Total anticipated payments under this agreement in 2007 are approximately $15 million USD.

Keephills 3 plant construction costs via the Keephills 3 Limited Partnership are anticipated to be approximately $1.6 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $800 million.

TransAlta signed a 25 year long-term contract in early 2007 with New Brunswick Power Distribution and Customer Service Corporation to provide 75 MW of wind power. We will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills") with an estimated capital cost of $130 million for the design, construction, transportation and assembly of the wind turbine generator towers and ancillary equipment. Commercial operations are expected to begin by the end of 2008, at which time final payments are also expected.

18. RELATED PARTY TRANSACTIONS

In August 2006, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican, a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

For the period November 2002 to November 2012, TA Cogen entered into various transportation swap transactions with a wholly owned subsidiary of TransAlta, TEC. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to Sheerness, which is operated by Canadian Utilities. 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 transaction was 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 with an external third party, therefore TransAlta has no risk other than counterparty risk.

19. SUBSEQUENT EVENTS

TransAlta Power

On Oct. 15, 2007 TransAlta Power, L.P. announced it had entered into a support agreement with Cheung Kong Infrastructure Holdings Limited (“CKI”) under which CKI agreed to offer $8.38 in cash per unit to acquire all of the outstanding units of TransAlta Power. The purchase price under the Offer represents a 15.7 per cent premium over the closing trading price of the units on the TSX on Oct. 12, 2007. The all-cash transaction is valued at approximately $629 million, excluding debt. This transaction does not have a material impact on TransAlta.

Power Purchase Agreement

On Oct. 12, 2007, the corporation signed an agreement amending the original power purchase agreement with the Ontario Electricity Financial Corporation (“OEFC”) for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant operations following the expiry of long term natural gas supply contracts. The agreement will be in effect from Nov. 1, 2007 until Dec. 31, 2012.

Mexico tax reform

On Oct. 1, 2007, the Mexican Government enacted law replacing the existing asset tax with a new flat tax effective Jan. 1, 2008. The flat tax is a minimum tax whereby the greater of income tax or flat tax is paid. In computing the flat tax, only 50 per cent of the undepreciated tax balance of certain capital assets acquired before Sept. 1, 2007 are deductible over 10 years. In addition, no deduction or credit is permitted in respect of interest expense and net operating losses for income taxes as at Dec. 31, 2007 cannot be carried forward to shelter flat tax. TransAlta is currently assessing the impact of this change but does not believe it will have a material impact on the carrying value of its Mexican investment.

SUPPLEMENTAL INFORMATION

(Annualized)			Sept. 30 2007		Dec. 31 2006
Closing market price		**$**	**31.30**	$	26.64
Price range (last 12 months)	High	**$**	**31.90**	$	26.91
	Low	**$**	**27.32**	$	20.22
Debt/invested capital (including non recourse debt)			**47.6%**		44.5%
Debt/invested capital (excluding non recourse debt)			**44.8%**		41.0%
Return on common shareholders' equity			**1.4%**		1.8%
Return on invested capital			**3.2%**		2.4%
Book value per share		**$**	**10.79**	$	11.99
Cash dividends per share		**$**	**1.00**	$	1.00
Price/earnings ratio (times)			**223.6 x**		121.1 x
Earnings coverage			**0.9 x**		**0.5 x**
Dividend payout ratio			**608.0%**		447.7%
Dividend coverage (times)			**3.6 x**		2.4 x
Dividend Yield			**3.2%**		3.8%
Cash Flow to Debt			**28.8%**		26.2%

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt – cash and interest-earning investments) / (debt + preferred securities + non-controlling interests + common equity)
Return on common shareholders' equity = net earnings excluding gain on discontinued operations / average of opening and closing common equity
Return on invested capital = (earnings before non-controlling interests and income taxes + net interest expense) / average annual invested capital
Book value per share = common shareholders' equity / common shares outstanding
Price/earnings ratio = current year's close / basic earnings per share from continuing operations
Earnings coverage = (net earnings + income taxes + net interest expense) / (net interest expense + capitalized interest)
Cash flow to total debt = cash flow from operations before changes in working capital / two-year average of total debt
Dividend payout = dividends / net earnings excluding gain on discontinued operations
Dividend coverage = cash flow from operating activities / common share dividends
Dividend yield = dividend per common share / current period's close price

GLOSSARY OF KEY TERMS

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, whether or not it is actually generating electricity.

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

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

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

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.

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

Megawatt - 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 fuel).

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