TRANSALTA CORP
Form 40-F
March 16, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

[Check one]

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

ý **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008
Commission file number 001-15214

TRANSALTA CORPORATION

(Exact name of Registrant as specified in its charter)

Not applicable	**Canada**	**4911**	**Not Applicable**
(Translation of Registrant's name into English (if applicable))	(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S Employer Identification Number (if applicable))

110-12th Avenue S.W., Box 1900, Station "M",
Calgary, Alberta, Canada, T2P 2M1,
(403) 267-7110
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System, 111 8th Avenue, 13th Floor,
New York, New York, 10011, (212) 894-8400
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered

Common Shares, no par value	**New York Stock Exchange**
Common Share Purchase Rights	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None
(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

ý Annual information form ý Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

At December 31, 2008, 197,622,215 common shares were issued and outstanding.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes o 82-

No ý

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No o

INCORPORATION BY REFERENCE

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended.

Form	Registration No.
S-8	333-72454
S-8	333-101470
F-10	333-155243

CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

A. Consolidated Audited Annual Financial Statements

For consolidated audited annual financial statements, including the report of independent chartered accountants with respect thereto, see pages **66** through 111 of the TransAlta Corporation 2008 Annual Report to shareholders included herein. See Exhibit 13.4 for the related supplementary note entitled "Reconciliation to United States Generally Accepted Accounting Principles" for a reconciliation of the important differences between Canadian and United States generally accepted accounting principles.

B. Management's Discussion & Analysis

For management's discussion & analysis, see pages 19 through 65 of the TransAlta Corporation 2008 Annual Report to shareholders included herein under the heading "Management's Discussion & Analysis."

For the purposes of this Form 40-F, only pages 66 through 111 and 19 through 65 of the TransAlta Corporation 2008 Annual Report to shareholders as referred to above shall be deemed incorporated herein by reference and filed, and the balance of such 2008 Annual Report, except as otherwise specifically incorporated by reference in the TransAlta Corporation Annual Information Form filed as Exhibit 13.1 hereto, shall not be deemed to be filed under the Exchange Act with the Securities and Exchange Commission as part of this Form 40-F.

DISCLOSURE 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 is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management 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 concluded that, as of December 31, 2008, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting.

Internal control over financial reporting refers to a process designed by, or under the supervision of, our chief executive officer and chief financial officer and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and members of our board of directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management evaluated the effectiveness of our internal control over financial reporting as of December 31, 2008 using the framework set forth in the report of the Treadway Commission's Committee of Sponsoring Organizations (COSO), "Internal Control Integrated Framework." Management has concluded that our internal control over financial reporting was effective as of December 31, 2008. Certain matters relating to the scope of Management's evaluation and limitations of management's conclusions are described below. See "Limitations and Scope of Management's Report on Internal Control over Financial Reporting."

Our independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2008. For Ernst & Young LLP's report see page 68 of the TransAlta Corporation 2008 Annual Report to shareholders under the heading "Independent Auditors' Report on Internal Controls Under Standards of the Public Company Accounting Oversight Board (United States)".

There has been no change in the internal control over financial reporting during the year covered by this report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

LIMITATIONS AND SCOPE OF MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process, and it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has not evaluated the internal controls of the Sheerness, CE Generation and Genesee 3 joint ventures (collectively, the "Excluded Entities"), in accordance with Frequently Asked Question No. 1, "Management's Report on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports," of the Office of the Chief Accountant of the Division of Corporation Finance of the U.S. Securities and Exchange Commission (revised Oct. 6, 2004). Accordingly, management's evaluation of the Company's internal control over financial reporting did not include an evaluation of the internal controls of any of the Excluded Entities, and management's conclusion regarding the effectiveness of the Company's internal control over financial reporting does not extend to the internal controls of any of the Excluded Entities.

Proportionate consolidation of the Excluded Entities contributes to the Company's financial statements in the amount of $1,680 million of the Company's total assets, $747 million of net assets, $481 million of revenues and $53 million of operating income. The Company's financial statements include the accounts of the Excluded Entities, accounted for via proportionate consolidation, in accordance with EITF 00-1, but management has been unable to assess the effectiveness of internal control at the Excluded Entities because the Company does not have the ability to dictate or modify the controls of the Excluded Entities and does not have the ability, in practice, to assess those controls.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its Audit and Risk Committee (the "ARC"). Mr. William D. Anderson has been determined to be an audit committee financial expert, within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley"), and is independent, as that term is defined by the New York Stock Exchange's ("NYSE") listing standards applicable to the Registrant. Mr. Gordon S. Lackenbauer has also been determined to be an audit committee financial expert for purposes of Section 407 of Sarbanes-Oxley and independent under the applicable NYSE listing standards. Under Securities and Exchange Commission rules the designation of persons as audit committee financial experts does not make them "experts" for any other purpose, impose any duties, obligations or liability on them that are greater than those imposed on members of their committee and the board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of their committee.

CODE OF ETHICS

The Registrant has adopted a code of ethics as part of its "Corporate Code of Conduct" that applies to all employees and officers which has been filed with the SEC. In addition, the Registrant has adopted a code of conduct applicable to all directors of the Company and a separate financial code of conduct which applies to all financial management employees. The Registrant's Corporate Codes of Conduct are available on its Internet website at www.transalta.com. There has been no waiver of the codes granted during the 2008 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2008 and 2007, Ernst & Young LLP and its affiliates were paid approximately $3,372,142 and $2,838,740 respectively, as detailed below:

	Year-ended December 31	
	2008	**2007**
Ernst & Young LLP		
Audit Fees	$2,594,183	$2,624,029
Audit-Related Fees	$ 432,343	$ 168,968
Tax Fees	$ 345,616	$ 45,743
All Other Fees	$	$
Total	**$ 3,372,142**	**$ 2,838,740**

No other audit firms provided audit services in 2008 or 2007.

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of the Company's annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English into French of the Company's financial statements and

other documents. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923. Total audit fees for 2007 include payments related to 2006 in the amount of $1,476,300.

Audit-Related Fees

The audit-related fees in 2008 and 2007 were primarily for work performed by Ernst & Young LLP in the provision of miscellaneous accounting advice provided to the Company.

Tax Fees

The majority of tax fees for 2008 related to the finalization of tax credit recoveries.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. The ARC has adopted a policy that prohibits the Company from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories as determined under Sarbanes-Oxley.

Percentage of Services Approved by the ARC

For the year ended December 31, 2008, none of the services described above were approved by the ARC pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

OFF-BALANCE SHEET ARRANGEMENTS

See page 47 of Exhibit 13.3.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 46 of Exhibit 13.3 under the heading "Liquidity and Capital Resources" and page 101 of Exhibit 13.2 under the heading "Commitments".

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing ARC. The members of the ARC are:

William D. Anderson (Chair)
Stephen L. Baum
Timothy W. Faithfull
Michael M. Kanovsky
Gordon S. Lackenbauer
Donna S. Kaufman (ex-officio member)

FORWARD LOOKING INFORMATION

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

Factors that may adversely impact the Corporation's forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which the Corporation operates; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving the Corporation's facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate the Corporation's facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) the Corporation's provision for income taxes; (xvi) legal proceedings involving the Corporation; (xvii) reliance on key personnel; (xviii) labour relations matters; and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in the documents filed herewith under Form 40-F and in other documents and filings made with securities regulatory authorities from time to time.

Readers are urged to consider these factors carefully in evaluating the forward looking statements and are cautioned not to place undue reliance on these forward looking statements. The forward looking statements included in this document are made only as of the date hereof and the Corporation does not undertake to publicly update these forward looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward looking events might or might not occur. The Corporation cannot assure you that projected results or events will be achieved.

UNDERTAKING

TransAlta Corporation undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSALTA CORPORATION

/s/ BRIAN BURDEN

Brian Burden
Executive Vice-President and Chief Financial Officer

Dated: March 16, 2009

EXHIBITS

13.1 TransAlta Corporation Annual Information Form for the year ended December 31, 2008.

13.2 Consolidated Audited Financial Statements for the year ended December 31, 2008 (included on pages 66 through 111 of the 2008 TransAlta Annual Report to Shareholders).

13.3 Management's Discussion and Analysis (included on pages 19 through 65 of the 2008 TransAlta Annual Report to Shareholders).

13.4 Reconciliation to United States Generally Accepted Accounting Principles of the 2008 Consolidated Audited Financial Statements.

23.1 Consent of Ernst and Young LLP Chartered Accountants.

31.1 Certification of Chief Executive Officer pursuant to Section 302 and Section 404 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 and Section 404 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of President and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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TRANSALTA CORPORATION

2009 RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 16, 2009

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form (**Annual Information Form**) is given as at or for the year ended December 31, 2008. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward-looking statements. All forward looking statements are based on TransAlta s beliefs as well as assumptions based on information available at the time the assumption was made. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as may , will , believe , expect , anticipate , intend , plan , foresee , potenti continue or other comparable terminology. These statements are not guarantees of TransAlta s future performance and are subject to risks, uncertainties and other important factors that could cause TransAlta s actual performance to be materially different from those projected.

Factors that may adversely impact the Corporation s forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which the Corporation operates; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving the Corporation s facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate the Corporation s facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) the Corporation s provision for income taxes; (xvi) legal proceedings involving the Corporation; (xvii) reliance on key personnel and (xviii) labour relations matters and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading Risk Factors in this Annual Information Form and in the documents incorporated by reference in this Annual Information Form, including the TransAlta Management s Discussion and Analysis for the year ended December 31, 2008 (the Annual MD&A).

Readers are urged to consider these factors carefully in evaluating the forward looking statements and are cautioned not to place undue reliance on these forward looking statements. The forward looking statements included in this document are made only as of the date hereof and the Corporation does not undertake to publicly update these forward looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward looking events might or might not occur. The Corporation cannot assure you that projected results or events will be achieved.

DOCUMENTS INCORPORATED BY REFERENCE

TransAlta s Audited Consolidated Financial Statements for the year ended December 31, 2008 and the Annual MD&A are hereby specifically incorporated by reference in this Annual Information Form. Copies of these documents are available on SEDAR at www.sedar.com.

CORPORATE STRUCTURE

Name and Incorporation

TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving the Corporation and TransAlta Utilities Corporation (**TransAlta Utilities** or **TAU**) under the *Canada Business Corporations Act*. The plan of arrangement, which was approved by shareholders on November 26, 1992, resulted in common shareholders of TransAlta Utilities exchanging their common shares for shares of TransAlta on a one-for-one basis. Upon completion of the arrangement, TransAlta Utilities became a wholly-owned subsidiary of TransAlta. On January 1, 2009, TransAlta was issued a Certificate of Amalgamation under the *Canada Business Corporations Act* in connection with the amalgamation of TransAlta Corporation, TransAlta Utilities, TransAlta Energy Corporation (**TransAlta Energy** or **TEC**) and Keephills 3 GP Ltd. The amalgamation was completed as part of a series of transactions involving TransAlta and certain of its subsidiaries and affiliates carried out to reorganize (the **Reorganization**) TransAlta s interest in certain of its assets.

The registered office and principal place of business of TransAlta is at 110 - 12th Avenue S.W., Calgary, Alberta, Canada, T2R 0G7.

Intercorporate Relationships

Effective January 1, 2009, the Corporation completed an internal reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta Corporation and TransAlta Generation Ltd., a wholly-owned subsidiary of TransAlta Corporation. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of the partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the *Canada Business Corporations Act*. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of the wind assets, and some of which are now held indirectly, in the case of the former generation assets and businesses of TAU and TEC.

As of January 1, 2009, the principal subsidiaries of the Corporation and their respective jurisdictions of formation are set out below.

Unless the context otherwise requires, all references to the "Corporation" and to "TransAlta" herein refer to TransAlta Corporation and its subsidiaries on a consolidated basis. References to "TransAlta Corporation" herein refer to TransAlta Corporation, excluding its subsidiaries.

OVERVIEW

TransAlta and its predecessors have been engaged in the production and sale of electric energy since 1909. The Corporation is among Canada s largest non regulated electricity generation and energy marketing companies with an aggregate net ownership interest of 7,976 megawatts (**MW**) of generating capacity[1] operating in facilities having approximately 9,697 MW of aggregate generating capacity. In addition, the Corporation has facilities under construction with a net ownership interest of 456 MW, of an aggregate generating capacity of 681 MW. The Corporation is focused on generating electricity in Canada, the United States and Australia through its diversified portfolio of facilities fuelled by coal, gas, hydroelectric, wind and geothermal resources.

In Canada, the Corporation holds a net ownership interest of 5,661 MW of electrical generating capacity in thermal, gas-fired, wind-powered and hydroelectric facilities, including 4,937 MW in Western Canada, 628 MW in Ontario and 96 MW in New Brunswick.

In the United States, the Corporation s principal facilities include a 1,376 MW thermal facility and a 248 MW gas-fired facility, both located in Centralia, Washington, which supply electricity to the Pacific northwest. The Corporation also holds a 50 per cent interest in CE Generation, LLC (**CE Generation**), through which it has an aggregate net ownership interest of approximately 385 MW of generating capacity in geothermal facilities in California and gas-fired facilities in Texas, Arizona and New York. In addition, the Corporation also has 6 MW of electrical generating capacity through hydroelectric facilities located in Washington and Hawaii.

In Australia, the Corporation has 300 MW of net electrical generating capacity from gas-fired generation facilities.

The Corporation regularly reviews its operations in order to optimize its generating assets and evaluates appropriate growth opportunities. The Corporation has in the past and may in the future make changes and additions to its fleet of coal, gas, hydro, wind and geothermal fuelled facilities.

The Corporation is organized into two business segments: Generation and Commercial Operations and Development. The Generation group is responsible for constructing, operating and maintaining electricity generation facilities. The Commercial Operations and Development group is responsible for managing the sale of production, purchasing natural gas, transmission capacity and market risks associated with the Corporation s generation assets and for non asset backed trading activities. Both 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, internal audit, and other administrative support.

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1 TransAlta measures capacity as the net maximum capacity that a unit can sustain over a period of time, which is consistent with industry standards. All capacity amounts are as of the date of this Annual Information Form and represent capacity owned and operated by the Corporation unless otherwise indicated.

GENERAL DEVELOPMENT OF THE BUSINESS

The significant events and conditions affecting TransAlta s business during the three most recently completed financial years are summarized below. Certain of these events and conditions are discussed in greater detail under the heading Business of TransAlta in this Annual Information Form.

Recent Developments

- On February 10, 2009, the Corporation reported that the 406 MW Sundance 4 facility had experienced an unplanned outage in December 2008 relating to the failure of an induced draft fan. At the time, the unit was derated to approximately 205 MW. The repair of the fan components by the original equipment manufacturer took longer than planned and, therefore, Unit 4 did not return to full service until February 23, 2009. As a result of the extended derate, first quarter production was reduced by 328GWh and net income declined by $17 million. The Corporation has given notice of a High Impact Low Probability Event to the PPA Buyer and the Balancing Pool which, if successful, will protect the Corporation from the financial loss and related penalties. The available penalties that the Corporation expects to recover in net income are anticipated to be $14 million.

- On January 29, 2009, the Board of Directors of the Corporation declared a quarterly dividend of $0.29 per common share, payable April 1, 2009 to holders of record on March 1, 2009. This represents a $0.02 per share increase in the quarterly dividend, yielding on an annualized basis a dividend of $1.16 per share.

- On January 29, 2009, the Corporation announced that it will be proceeding with the addition of two 23 MW efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded to 406 MW and are expected to be operational by the end of 2011 and 2012, respectively. The total capital cost of the projects is estimated at $68 million.

- Effective January 1, 2009, the Corporation completed an internal reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta and TransAlta Generation Ltd., a wholly-owned subsidiary of TransAlta. TransAlta Generation Partnership is managed by TransAlta pursuant to the terms of the partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the *Canada Business Corporations Act*. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of the wind assets, and some of which are now held indirectly, in the case of the former generation assets and businesses of TAU and TEC.

Year Ended December 31, 2008

- On December 31, 2008, the Corporation announced that the 96 MW, $170 million Kent Hills Wind Farm had begun commercial operation. The wind farm consists of 32 Vestas V90, 3MW wind turbines. The capacity from this project is sold under a power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation (**New Brunswick Power**).

- On October 8, 2008, the Corporation announced the completion of the sale of its Mexican businesses to Intergen Global Ventures B.V. II for a sale price of US$303.5 million. The sale included the 252 MW gas/diesel combined cycle gas plant in Campeche, a 259 MW combined cycle gas plant in Chihuahua and all associated commercial arrangements.

- On May 27, 2008, the Corporation announced that, commencing in 2009, it would be constructing another 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital cost for this expansion of the Summerview wind power project is expected to be $123 million. The capacity from this project is expected to be sold on the Alberta Power Pool.

- On May 5, 2008, the Corporation announced that it had received regulatory approval from the Toronto Stock Exchange (**TSX**) for the continuation of its normal course issuer bid (**NCIB**) program. Under the NCIB program, the Corporation has approval to purchase, for cancellation, up to 19.9 million of its common shares, representing 10 per cent of its public float as of April 23, 2008.

- On April 21, 2008, the Corporation announced a 53 MW efficiency uprate at Unit 5 of its Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009.

- On April 3, 2008, TransAlta announced a partnership with Alstom LLC to develop a one million tonne/year carbon capture and storage project at one of TransAlta s coal-fired power stations in Alberta. This project has been shortlisted by the Alberta Government for contributory funding as part of the province s $2 billion carbon capture and storage (**CCS**) program, with a decision expected by June 30, 2009.

- On February 20, 2008, the Corporation announced it had signed a purchase and sale agreement with Intergen Global Ventures B.V. pursuant to which Intergen agreed to pay the Corporation US$303.5 million in cash for its Mexican assets.

- On February 13, 2008, the Corporation announced that, commencing in 2009, it would be constructing a 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital costs for this Blue Trail wind power project is expected to be $115 million. The capacity from this project is expected to be sold on the Alberta Power Pool.

- On February 1, 2008, the Board of Directors of the Corporation declared a quarterly dividend of $0.27 per common share, payable April 1, 2008 to holders of record on March 1, 2008. This represents a $0.02 per share increase in the quarterly dividend, yielding on an annualized basis a dividend of $1.08 per share.

Year Ended December 31, 2007

- During the third quarter, the Corporation completed an uprate on the Sundance Unit 4 facility. A final measurement took place in the fourth quarter of 2007 and the generating capacity added as a result of this uprate was 53 MW.

- On September 11, 2007, the Corporation announced it had received regulatory approval to increase the number of shares it may purchase under its NCIB program. As a result, the Corporation was authorized to purchase for cancellation up to 20.2 million shares or approximately 10 per cent of the 202 million common shares issued and outstanding as of April 23, 2007.

- On July 17, 2007, the Corporation amended the power purchase agreement with New Brunswick Power to increase capacity at its Kent Hills wind power facility from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills project will also increase by $40 million, from $130 million to $170 million. The Corporation also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., to acquire its Fairfield Hill wind power site, including an option to develop the site at a future date.

- On June 21, 2007, TransAlta Utilities 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. The total dragline purchase costs are approximately $150 million, with final payments for goods and services due by May 2010. The total payments made under this agreement in 2007 were $18 million.

- On February 26, 2007, the Corporation and EPCOR Power Development Corporation (**EPCOR**) announced that they were proceeding with building the 450 MW Keephills 3 power project located approximately 70 kilometres west of Edmonton, Alberta. The capital cost for the project, including mine capital, is expected to be approximately $1.6 billion and is expected to be completed at the end of the first quarter of 2011. Through the Keephills 3 Limited Partnership (**K3LP**), an affiliate of the Corporation, TransAlta and EPCOR will be equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and EPCOR responsible for the construction. Upon completion, it is expected that TransAlta will operate the facility and EPCOR and TransAlta will independently dispatch and market their share of the unit s electrical output. The project has received approval from the Alberta Energy and Utilities Board and from Alberta Environment.

- On January 19, 2007, the Corporation announced that it had been awarded a 25-year Power Purchase Agreement (**PPA**) to provide 75 MW of wind power to New Brunswick Power. Under the agreement, TransAlta will construct, own and operate a wind power facility in New Brunswick. The capital cost of the project is estimated to be $130 million. The project is subject to regulatory and environmental approvals and is expected to begin commercial operations by the end of 2008. Natural Forces Technologies Inc., an Atlantic Canada based wind developer, is TransAlta s co-development partner in this project.

- On January 2, 2007, the Corporation redeemed, at par, all of its outstanding 7.75 per cent preferred securities, with an outstanding principal amount of $175 million.

Year ended December 31, 2006

- On December 18, 2006, TransAlta Utilities assigned its rights in the development agreement it held with EPCOR, governing the joint development of the Keephills 3 power project, to K3LP. K3LP subsequently sold a 50 per cent undivided interest in the Keephills 3 power project to the EPCOR Power Development (K3) Limited Partnership and has entered into a joint venture agreement governing the continued development of the Keephills 3 power project. In the event the Keephills 3 power project proceeds to operation, it is anticipated that TransAlta will be the operator of the project pursuant to an operations and maintenance agreement and coal supply agreement.

- On November 27, 2006, TransAlta announced it would immediately stop mining operations at its Centralia, Washington coal-mine. TransAlta also announced that it had entered into agreements to purchase and transport coal from the Powder River Basin to fuel TransAlta s Centralia thermal facility.

- On November 17, 2006, TransAlta Utilities entered into a settlement agreement with Canadian National Railway Company for a portion of outstanding claims for lost margin and incremental expenses relating to the train derailment and resulting oil spill into Lake Wabamun in 2005. The terms of the settlement are subject to a confidentiality agreement and cannot be disclosed.

- On February 17, 2006, a wholly-owned subsidiary of TransAlta, together with a subsidiary of Mid-American Energy Company (**Mid-American**), entered into an agreement to purchase a 10 MW hydro facility in Hawaii to be held directly by the Wailuku Holding Company LLC, a company jointly and equally owned by TransAlta and Mid-American.

- On February 15, 2006, TransAlta announced it had signed a five-year agreement with the Ontario Power Authority (**OPA**) for the supply of electricity from TransAlta s Sarnia Regional Cogeneration Power Plant. Under the terms of the agreement, Transalta will be available to supply an average of 400 MW of electricity to the Ontario electricity market. The supply contract is effective until December 31, 2010.

- On February 1, 2006, TransAlta Utilities entered into a development agreement with EPCOR to jointly pursue the Keephills 3 power project. Keephills 3 is a proposed 450 MW facility adjacent to TransAlta s existing Keephills facility, approximately 70 kilometres west of Edmonton, Alberta.

BUSINESS OF TRANSALTA

Generation Business Segment

The following table summarizes the Corporation s generation facilities which are operating, under construction or under development, as at January 31, 2009:

Region	**Facility**	**Capacity (MW)**	**Ownership (%)**	**Net Capacity Ownership Interest**	**Fuel**	**Revenue Source**	**Contract Expiry Date**
	Sundance (1)	2,126	100	2,126	Coal	Alberta PPA / Merchant (2)	2017, 2020
	Keephills (3)	812	100	812	Coal	Alberta PPA	2020
	Sheerness	780	25	195	Coal	Alberta PPA	2020
	Wabamun	279	100	279	Coal	Merchant	-
	Genesee 3	450	50	225	Coal	Merchant	-
	Keephills 3 (4)	450	50	225	Coal	Merchant	-
Western Canada (28 Facilities)	Fort Saskatchewan	118	30	35	Gas	Long-term contract (**LTC**)	2019
	Meridian	220	25	55	Gas	LTC	2024
	Poplar Creek	356	100	356	Gas	LTC/Merchant	2024
	Hydro assets (5)	801	100	801	Hydro	Alberta PPA	2013-2020
	Castle River (6)	44	100	44	Wind	LTC/Merchant	2011
	McBride Lake	75	50	38	Wind	LTC	2024
	Summerview 1 (7)	70	100	70	Wind	Merchant	-
	Blue Trail (4)	66	100	66	Wind	Merchant	-
	Summerview 2 (4)	66	100	66	Wind	Merchant	-
	Total Western Canada	**6,713**		**5,393**			
	Mississauga	108	50	54	Gas	LTC	2017
Eastern Canada (5 Facilities)	Ottawa	68	50	34	Gas	LTC	2012
	Windsor	68	50	34	Gas	LTC/Merchant	2016
	Sarnia (8)	506	100	506	Gas	LTC/Merchant	2022
	Kent Hills	96	100	96	Wind	PPA	2033
	Total Eastern Canada	**846**		**724**			
	Centralia (9)	1,376	100	1,376	Coal	Merchant	-
	Centralia Gas	248	100	248	Gas	Merchant	-
	Power Resource	212	50	106	Gas	Merchant	-
	Saranac	240	37.5	90	Gas	LTC	2009
United States (17 Facilities)	Yuma	50	50	25	Gas	LTC	2024
	Imperial Valley Geothermal Facilities (10)	327	50	164	Geothermal	LTC/Merchant	2016-2029
	Skookumchuk	1	100	1	Hydro	-	-
	Wailuku	10	50	5	Hydro	LTC	2023
	Total US	**2,464**		**2,015**			
Australia (5 Facilities)	Parkeston	110	50	55	Gas	LTC	2016
	Southern Cross (11)	245	100	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			
Total		**10,378**		**8,432**			

Notes:

(1) Includes a 53 MW uprate expected to be commercial in 2009.

(2) Merchant capacity refers to 53 MW and 44 MW uprates on units 4 and 6, respectively.

(3) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively.

(4) These facilities are currently under development.

(5) Comprised of 13 facilities.

(6) Includes 7 individual turbines at other locations.

(7) Comprised of 2 facilities.

(8) Sarnia s net maximum capacity (**NMC**) has been adjusted from 575 MW due to decommissioning of equipment at the facility.

(9) Centralia Thermal s NMC has been reduced from 1,404 MW to reflect a lower plant output as a result of its conversion to burning Powder River Basin coal.

(10) Comprised of 10 facilities.

(11) Comprised of 4 facilities.

Canada: Alberta

Thermal facilities

The following table summarizes the Corporation s western Canadian thermal generation facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Wabamun (1)	Wabamun Unit No. 4	279	100	1968
Sundance	Sundance Unit No. 1	280	100	1970
	Sundance Unit No. 2	280	100	1973
	Sundance Unit No. 3	353	100	1976
	Sundance Unit No. 4	406	100	1977
	Sundance Unit No. 5 (2)	406	100	1978
	Sundance Unit No. 6	401	100	1980

Keephills	Keephills Unit No. 1 (3)	406	100	1983
	Keephills Unit No. 2 (3)	406	100	1984
	Keephills Unit No. 3 (4)	450	50	2011
Sheerness	Sheerness Unit No. 1	390	25	1986
	Sheerness Unit No. 2	390	25	1990
Genesee	Genesee 3	450	50	2005
Total		**4,897**		

Notes:

(1) Wabamun unit 4 is expected to be removed from service upon the expiry of its license in 2010.

(2) Includes a 53 MW uprate expected to be commercial in 2009.

(3) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively.

(4) This facility is currently under development.

The Keephills, Sundance and Wabamun facilities (the **Alberta thermal plants**) are located approximately 70 kilometres west of Edmonton, Alberta and are owned by TransAlta. The Sheerness facility is jointly owned by TransAlta Cogeneration, L.P. (**TA Cogen**), an Ontario limited partnership, and ATCO Power (2000) Ltd. (**ATCO Power**). The Genesee facility is jointly owned by TransAlta and EPCOR. TransAlta s thermal plants are generally base load plants, meaning that they are expected to operate for long periods of time at or near their rated capacity. Availability is an important measure of the economic success of a thermal plant. The weighted equivalent availability factor for the Alberta thermal plants in 2008 was 82.9 per cent compared with 87.1 per cent in 2007 and 88.7 per cent in 2006. For the Sheerness facility, the weighted equivalent availability factor was 94.1 per cent in 2008 compared to 94.4 per cent in 2007 and 92.2 per cent in 2006. For the Genesee 3 facility, the weighted equivalent availability factor was 78.2 per cent in 2008 compared to 92.9 per cent in 2007 and 96.9 per cent in 2006.

Fuel requirements for TransAlta s thermal power facilities are supplied by surface strip coal-mines located in close proximity to the facilities. TransAlta owns two surface mines in Alberta that supply coal to its Alberta thermal plants. The Whitewood mine supplies the Wabamun plant and the Highvale mine supplies the Sundance and Keephills facilities. TransAlta estimates that the recoverable coal reserves contained in these mines are expected to be sufficient to supply the anticipated requirements for the life of these facilities including running post PPA expiry and plant expansion.

Coal for the Sheerness facility is provided from the adjacent Sheerness mine. The coal reserves of the mine are owned, leased or controlled jointly by TA Cogen, ATCO Power and Prairie Mines & Royalties Limited (**PMRL**).

TA Cogen and ATCO Power have entered into coal supply agreements with PMRL, which operates the mine, to supply coal until 2026.

Coal for the Genesee 3 facility is provided from the adjacent Genesee mine. The coal reserves of the mine are owned, leased or controlled jointly by PMRL and EPCOR. The Corporation has entered into coal supply agreements with PMRL, which operates the mine, to supply coal for the life of the facility.

In February 2001, the Corporation announced a proposal for a 900 MW expansion at its Keephills facility. Although the Corporation received regulatory approval to proceed with the expansion, an application was made, in December 2004, to the AEUB to amend its 900 MW permit to allow for the construction of a smaller 450 MW facility using improved technology.

On February 1, 2006, the Corporation entered into a development agreement with EPCOR to jointly pursue the 450 MW Keephills 3 power project. On December 18, 2006, the Corporation assigned its rights in the development agreement which it held with EPCOR for the joint development of the Keephills 3 power project to K3LP, an affiliate of the Corporation. K3LP subsequently sold a 50 per cent undivided interest in the Keephills 3 power project to the EPCOR Power Development (K3) Limited Partnership and has entered into a joint venture agreement governing the continued development of the Keephills 3 power project. The project received approval from the Alberta Energy and Utilities Board and from Alberta Environment.

On February 26, 2007, the Corporation and EPCOR commenced construction of the net 450 MW Keephills 3 power project. The capital cost for the project, including mine capital, is expected to be approximately $1.6 billion and is expected to be completed at the end of the first quarter of 2011. Through K3LP, TransAlta and EPCOR will be equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and EPCOR responsible for construction. Upon completion, it is expected that TransAlta will operate the facility and EPCOR and TransAlta will independently dispatch and market their share of the unit s electrical output. The Corporation will also provide coal to the facility through the Highvale mine. On January 29, 2009, the Corporation s estimate of total costs for Keephills 3 increased by $73 million, due to higher material and labour costs, for a total projected cost of $1.7 billion. The Corporation continues to monitor the costs and will look for opportunities to reduce the cost increases.

Gas fired facilities

The following table summarizes the Corporation s western Canadian gas fired generation facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Lloydminster, SK	Meridian	220	25	1999
Fort McMurray, AB	Poplar Creek	356	100	2001

Fort Saskatchewan, AB	Fort Saskatchewan	118	30	1999
Total		**694**		

The Corporation s interests in the Meridian and Fort Saskatchewan facilities are held through TA Cogen. See TA Cogen .

The Meridian plant is located in Lloydminster, Saskatchewan and is owned by TA Cogen and Husky Oil Operations Limited. The Meridian plant sells electricity to Saskatchewan Power Corporation, a Crown corporation owned by the Province of Saskatchewan, and steam to a heavy oil upgrader in Lloydminster, Saskatchewan.

The Poplar Creek plant is located in Fort McMurray, Alberta and is owned by the Corporation. This 356 MW cogeneration plant became fully operational in the first quarter of 2001 and delivers approximately 200 MW of electricity and steam to Suncor Energy Inc. (**Suncor**). Any surplus power not used by Suncor is available for sale by the Corporation to other parties, in which case Suncor is entitled to a share of that revenue, under certain conditions.

The Fort Saskatchewan plant is located in Fort Saskatchewan, Alberta and is owned by TA Cogen and Air Liquide Canada Inc. The 118 MW Fort Saskatchewan gas fired combined cycle cogeneration plant in Alberta provides electricity and steam to Dow Chemical Canada Inc.

Hydroelectric facilities

The following table summarizes the Corporation s western Canadian hydroelectric facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Bow River System	Horseshoe	14	100	1911
	Kananaskis	19	100	1913, 1951
	Ghost	51	100	1929, 1954
	Cascade	36	100	1942, 1957
	Barrier	13	100	1947
	Bearspaw	17	100	1953, 1954
	Pocaterra	15	100	1955
	Interlakes	5	100	1955
	Spray	103	100	1951, 1960
	Three Sisters	3	100	1951
	Rundle	50	100	1951, 1960
			100	
North Saskatchewan River System	Brazeau	355	100	1965, 1967
	Bighorn	120	100	1972
Total		**801**		

The Corporation s hydroelectric facilities are primarily peaking plants, meaning they are generally only operated during times of peak demand.

Wind Generation Facilities

The following table summarizes the Corporation s wind generation facilities:

Location	**Plant**	**Commissioning Dates**

		Capacity (MW)	Ownership (%)	
Fort MacLeod	McBride Lake	75	50	2003
Pincher Creek	Castle River and Other	44	100	1997 2001
Pincher Creek	Summerview 1	70	100	2004
New Brunswick	Kent Hills	96	100	2008
Fort Macleod	Blue Trail (1)	66	100	2009
Pincher Creek	Summerview 2 (1)	66	100	2010
Total		**417**		

Note:

(1) Facility under development reflects expected capacity and commissioning date.

The Corporation owns and operates approximately 248 MW of net capacity (excluding facilities under development) and operates approximately 285 MW of capacity primarily in three wind farms in southwestern Alberta and one in New Brunswick.

Castle River is a 40 MW facility comprised of 59 Vestas V47 (660 kW) turbines and 1 Vestas V44 (600 kW) turbine located at Pincher Creek, Alberta. The facility is 71 per cent contracted primarily to ENMAX Energy Corp.

(**ENMAX**) and is the sole Green Energy® provider to the City of Calgary s Ride the Wind Light Rail Transit program. The Corporation also owns and operates seven additional turbines totalling 4 MW located individually in the Pincher Creek, Fort Macleod and Hillspring areas of southwestern Alberta.

McBride Lake is a 75 MW facility comprised of 114 Vestas V47 (660 kW) turbines located at Fort MacLeod, Alberta. It was constructed by the Corporation and has been producing electricity since the third quarter of 2003. McBride Lake is operated by the Corporation and is owned by the Corporation and ENMAX Green Power Inc. The output from the facility is 100 per cent contracted in the form of a 20 year PPA with ENMAX. The Corporation is also entitled to receive Wind Power Production Incentive (**WPPI**) payments from the federal government at $12/MWh in respect of the McBride Lake facility until 2013.

On October 13, 2004, TransAlta announced the commencement of commercial operations at its $100 million Summerview 68 MW wind farm located approximately 15 kilometres northeast of Pincher Creek, Alberta. The Summerview facility, which comprises 38 1.8 MW turbines, together with an existing 1.8 MW turbine in the area, brings the total wind generation capacity at that location to 70 MW. The Summerview wind farm is a merchant facility but is entitled to receive WPPI payments from the Federal Government at $10/MWh until 2014.

On January 19, 2007, the Corporation announced that it had been awarded a 25 year PPA to deliver 75 MW of wind power to New Brunswick Power. On July 17, 2007, the Corporation announced it had amended its PPA with New Brunswick Power from 75 MW to 96 MW bringing the total capital cost for the project to an estimated $170 million. The project was completed by the end of 2008. Natural Forces Technologies Inc. (**Natural Forces**), an Atlantic Canada based wind developer, is TransAlta s co-development partner in this project and Natural Forces has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

On February 13, 2008, the Corporation announced that, commencing in 2009, it would be constructing a 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital cost for this Blue Trail wind power project is expected to be $115 million. The capacity from this project is expected to be sold on the Alberta Power Pool. The Blue Trail wind farm is entitled to receive payments from Natural Resources Canada (**NRCan**), a division of the federal government, through the eco Energy for Renewable Power (**eERP**) program.

On May 27, 2008, the Corporation announced that, commencing in 2009, it would be constructing another 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital costs for this expansion of the Summerview 2 wind power project is expected to be $123 million. The capacity from this project is expected to be sold on the Alberta Power Pool. With this announcement, existing and planned wind generation facilities owned and operated by the Corporation total 419 MW. The Summerview 2 wind farm expansion is entitled to receive payments from NRCan through the eERP program.

All of the electricity generated and sold by the Corporation s wind division is from generation facilities that are EcoLogo certified. The Corporation is an EcoLogo certified distributor of Alternative Source Electricity through Environment Canada s Environmental Choice program. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards. The Corporation s wind facilities constructed after April 2001, also qualify for the Green E and Green Leaf certifications.

Alberta PPAs

All of the Corporation s Alberta thermal and hydroelectric facilities, other than the Wabamun, Genesee 3 facilities, and uprated capacity, operate under Alberta PPAs. The Alberta PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each thermal plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which electricity is to be supplied. The Corporation bears the risk or retains the benefit of volume variances (except for those arising from events considered to be force majeure, in the case of the thermal plants) and any change in costs (unless due to a change in law) required to maintain and operate the facilities.

Under the Alberta PPAs, for the formerly regulated thermal facilities, the Corporation is exposed to electricity price risk if availability declines below contracted levels (other than as a result of outages caused by an event of force majeure). In such circumstances, the Corporation must pay a penalty for the lost availability based upon a price equal to the 30 day rolling average of Alberta s market electricity prices. This rolling average provision attempts to mitigate price spikes that can occur as a result of sudden outages. The Corporation attempts to further mitigate this exposure by maintaining contracted and uncontracted capacity in the market, through operating and maintenance practices, and through hedging activities.

The Corporation s hydroelectric facilities are not contracted on a facility-by-facility basis; rather, facilities are aggregated in a single Alberta PPA which provides for financial obligations for energy and ancillary services based on hourly targets. These targeted amounts are met by the Corporation through physical delivery or third party purchases.

The Corporation s compensation under the Alberta PPAs is based on a pricing formula which replaced the cost of service regime that applied previously under utility regulation. Key elements of the pricing formula are the amount of common equity deemed to form part of the capital structure, the amount of risk premium attributable to deemed common equity and a recovery of fixed and variable costs. Common equity is deemed to be 45 per cent of total capital and the return on equity is set annually at a 4.5 per cent premium over the rate on a 10-year Government of Canada Bond.

The pricing formula includes a provision for site restoration costs of the thermal generating plants for the whole term of the PPA. Until 2017, if the costs recovered are insufficient, then the Corporation can apply to the Balancing Pool to recover the incremental portion. The Alberta PPAs include, as part of the capacity payment for hydroelectric operations, an amount for decommissioning.

The expiry dates for the Corporation s Alberta PPAs, range from 2013 to 2020. With the expiry of the PPA at the Wabamun facility, the Corporation procured an extension of the license to operate Unit four of the Wabamun facility until March 31, 2010. The Corporation holds various licenses from Alberta Environment and the AEUB to operate its other facilities, most of which are renewed every few years. The Corporation is evaluating the economics of running assets post-PPA expiry. Upon the expiry of the PPAs and subject to procuring an extension of the licenses, if required, the Corporation will then be able to sell its electricity to the Alberta Power Pool and to third party purchasers through direct sales agreements. The Corporation is currently selling most of its electricity from the Wabamun facility on the spot market.

The Alberta PPAs (together with legislation which applies thereto) permit the Balancing Pool, an entity established by the Government of Alberta, directly or indirectly as successor to the power purchaser under the Alberta PPAs, to terminate the Alberta PPAs in certain circumstances. These termination provisions are similar to those found in some PPAs entered into by government related power purchasers. The Corporation will be entitled to receive a lump sum payment in connection with any such termination, other than a termination resulting from the Corporation s default and will thereafter be able to sell the output from any affected facilities for its own account.

Canada: Ontario

The Corporation s Ontario generating facilities are summarized in the following table:

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates
Sarnia	Sarnia	506	100	2003
Ottawa	Ottawa	68	50	1992
Mississauga	Mississauga	108	50	1992

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates

Windsor	Windsor	68	50	1996
Total		**750**		

The Sarnia facility is a combined cycle cogeneration facility which is owned by the Corporation. The Corporation acquired 135 MW of electric generation capacity in 2002, and in March 2003 the Corporation acquired the remaining 440 MW of capacity. On January 1, 2009, the Corporation applied, and subsequently received approval, to decommission a 69 MW turbine at Sarnia. The 506 MW facility provides steam and electricity to nearby facilities owned by Dow Chemical Canada Inc., Lanxess (formerly Bayer Inc.), Nova Chemicals (Canada) Ltd. and Suncor Energy Products Inc. On February 15, 2006, TransAlta announced that it had signed a five-year agreement with the OPA for production at its Sarnia facility. Under the terms of the contract, TransAlta will be available to supply an average of 400 MW of electricity to the Ontario electricity market. The supply contract is effective until December 31, 2010. On December 24, 2008, the Minister of Energy and Infrastructure directed the OPA to seek contracts with certain energy providers in Ontario, namely those listed in a December 14, 2005 Direction which includes Sarnia, for the supply of clean and efficient electricity generation. The OPA is not required to enter a new contract with the energy provider where an agreement cannot be reached as to what constitutes a reasonable cost to Ontario electricity consumers and a reasonable balancing of risk and reward.

The Ottawa plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 68 MW of electrical energy. This capacity is sold under a long-term contract with the Ontario Electricity Financial Corporation (**OEFC**), an agency of the Province of Ontario. This agreement expires in 2012. The Ottawa plant also provides thermal energy to the member hospitals and treatment centers of the Ottawa Health Sciences Centre, National Defence Medical Centre and the Perley and Rideau Veterans Health Centre.

The Mississauga plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 108 MW of electrical energy. This capacity is contracted under a long-term contract with the OEFC which expires in 2017. The Mississauga Plant provided cogeneration services to Boeing Canada Inc. (**Boeing**) until July 2005 at which time Boeing exercised its right under the cogeneration services agreement to no longer take and pay for cogeneration services due to the recent closure of its manufacturing facility. Boeing remains entitled to any steam credits based on the total plant electricity generation revenue. On or prior to each of January 1, 2013, 2018 and 2023, Boeing may give notice of its intention to continue to purchase, or discontinue, cogeneration services. In addition, on those same dates, Boeing has the option to require the removal of the Mississauga Plant from the leased lands or purchase the Mississauga Plant at its net salvage value.

The Windsor plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 68 MW of electrical energy. Currently, 50 MW of the capacity is sold under a long-term contract to the OEFC. This agreement expires in 2016. The Windsor plant also provides thermal energy to Chrysler Canada Inc. s minivan assembly facility in Windsor. In 2003, an agreement was reached with the OEFC to sell the remaining 18 MW to the Ontario power market when it is economic to do so.

United States

The Corporation s generation facilities in the United States are summarized in the following table:

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates

Washington	Centralia Coal No. 1	688	100	1971
	Centralia Coal No. 2	688	100	1971
	Centralia Gas	248	100	2002
	Skookumchuk	1	100	1970

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates

New York	Saranac	240	37.5	1994
California	Vulcan	34	50	1986
	Del Ranch	38	50	1989
	Elmore	38	50	1989
	Leathers	38	50	1990
	CE Turbo	10	50	2000
	Salton Sea I	10	50	1987
	Salton Sea II	20	50	1990
	Salton Sea III	50	50	1989
	Salton Sea IV	40	50	1996
	Salton Sea V	49	50	2000
Texas	Power Resources	212	50	1988
Arizona	Yuma	50	50	1994
Hawaii	Wailuku	10	50	1993
Total		**2,464**		

Centralia

The Corporation owns a two unit 1,376 MW thermal facility and a 248 MW gas-fired facility in Centralia, Washington, located south of Seattle. The Corporation also owns a 1 MW hydro-electric generating facility and related assets on the Skookumchuk River near Centralia, which facilities are used to provide reliable water supply to TransAlta s other generation facilities at Centralia. TransAlta also owns a coal-mine adjacent to the Centralia facility, however, it stopped all mining operations at the mine in late 2006.

The Corporation has entered into a number of medium to long-term energy sales agreements from the Centralia facility. The Corporation also sells electricity from the Centralia facility into the Western Electricity Coordinating Council and, in particular, on the spot market in the U.S. Pacific Northwest energy market. The Corporation s strategy is to balance contracted and non contracted sales of electricity to manage production and price risk.

The Corporation stopped mining operations at its Centralia coal-mine on November 27, 2006. Prior to that date, the Centralia mine produced approximately five to six million tons of coal annually, or approximately 70 to 85 per cent of the Centralia plant s annual coal requirements. Although the Corporation estimates that certain coal reserves remain to be extracted, the Corporation has not yet received permits for, nor developed the new area, from which this coal could be produced. The Corporation has entered into contracts to purchase and transport coal from the Powder River Basin in Montana and Wyoming to fuel its facility until such time, if any, as it is economic to pursue the extraction of coal at its Centralia mine.

CE Generation

On January 29, 2003, TransAlta announced the completion of the acquisition from El Paso Corporation (**El Paso**) of a 50 per cent interest in CE Generation, for total consideration of approximately US$240 million, which included approximately US$35 million for working capital. The CE Generation acquisition included the right to a 50 per cent interest in Salton Sea VI, a geothermal project, in the Imperial Valley, California. While there is still future development potential for CE Generation in the Imperial Valley, the Salton Sea VI project that was being pursued when TransAlta acquired its interest in CE Generation was never developed.

CE Generation, through its subsidiaries, is primarily engaged in the development, ownership and operation of independent power production facilities in the United States using geothermal and natural gas resources. CE Generation holds a net ownership interest of approximately 385 MW in 13 facilities, having an aggregate operating capacity of 829 MW, including 327 MW of geothermal generation in California and 502 MW of gas fired cogeneration in New York, Texas and Arizona.

CE Generation affiliates currently operate 10 geothermal facilities in Imperial Valley, California. Each of the geothermal facilities sells electricity pursuant to independent, long term contracts.

CE Generation affiliates currently operate three natural gas fired facilities in Texas, Arizona and New York State, having an aggregate generation capacity of 502 MW. The Arizona facility sells its output pursuant to long-term contracts while the Texas facility has contracted a tolling agreement for capacity, which expires at the end of 2009. The New York facility sells its output pursuant to long-term contracts until mid-2009, after which point its capacity will be sold on the spot market. The intent is to re-contract both the New York facility and the Texas facility under a tolling agreement for capacity.

Wailuku

On February 17, 2006, a subsidiary of TransAlta, together with a subsidiary of Mid-American entered into an arrangement to purchase a 10 MW hydro facility in Hawaii to be held directly by the Wailuku Holding Company LLC. Each of TransAlta and Mid American hold a 50 per cent interest in the facility. The facility sells electricity pursuant to the terms of a 30 year long-term contract with the Hawaii Electricity Light Company.

Australia

The Corporation holds interests in Western Australia consisting of the 110 MW Parkeston generation facility through a 50/50 joint venture with NP Kalgoorlie Pty Ltd, a subsidiary of Newmont Australia Limited, and the 245 MW Southern Cross Energy gas and diesel generation facilities. Most of TransAlta s generation supplies two large mining companies through long-term capacity contracts and the remaining amount of surplus energy and capacity is sold into Australia s Wholesale Electricity Market which was introduced in Western Australia in late 2006.

TA Cogen

The Corporation s interest in the 220 MW Meridian natural gas fired generation facility in Saskatchewan, the 780 MW Sheerness thermal generation facility, the 118 MW Fort Saskatchewan gas fired cogeneration facility in Alberta, and the Mississauga, Ottawa and Windsor Essex facilities in Ontario, are held through TA Cogen, an Ontario limited partnership owned 50.01 per cent by subsidiaries of TransAlta and 49.99 per cent by Stanley Power Inc., a subsidiary of Cheung Kong Infrastructure Holdings Limited.

Commercial Operations and Development

The Commercial Operations Development group provides a number of strategic functions to the Corporation, including the following:

- Gathering and assessing market intelligence, enabling management to more effectively engage in strategic planning and decision making for the Corporation. This includes identifying and ranking markets which are the most attractive to enter, and developing strategies and plans to effectively compete in each market where the Corporation operates;

- Identifying specific opportunities to develop, acquire, or divest of generation assets in markets where the Corporation is operating or growing and completing the business arrangements so the Corporation can either make investment or divesture decisions;

- Negotiating and entering into contractual agreements with customers for the sale of output from the Corporation s generating assets, including electricity, steam or other energy related commodities;

- Scheduling physical deliveries of natural gas supplies used to generate electricity and the electrical generation outputs from each asset to meet contractual obligations while managing the physical and financial risks associated with the generation and transmission of electrical energy, including during those periods of unplanned outages;

- Increasing the value of electricity output and fuel inputs from each generating asset through a variety of regional portfolio optimization strategies in both the current year and over the long-term; and

- Recommending optimum maintenance schedules and operating levels according to current and anticipated market conditions that will maximize earnings from each of the generation assets.

Beyond these functions, the Commercial Operations Development group derives additional revenue and earnings from the wholesale trading of electricity and other energy related commodities and derivatives.

The group seeks to manage and limit risk exposures from both financial and physical positions, as well as counterparty risks. The key risk control activities of the Commercial Operations Development group, in conjunction with other functions of the Corporation, include credit review approval and reporting, risk measurement monitoring and reporting, validation of transactions, and trading portfolio valuation monitoring and reporting.

The Corporation uses mark-to-market valuation and the application of a value at risk (**VAR**) determination for risk control practices for its trading portfolios. This approach is a measure of assessing the potential trading losses that the Corporation could experience over a given time, due to fluctuations in energy prices in each market. The Corporation s policy is to actively manage and limit the group s aggregate VAR exposure within board approved limits.

Competitive Environment

TransAlta is the largest generator of electricity in Alberta, measured by capacity, and has a significant portfolio of generation assets in the Pacific Northwest and western U.S. The Corporation also owns and operates generating assets in eastern Canada and Australia.

The Corporation expects continued long-term growth of electricity demand in its core markets although short-term growth rates may be significantly reduced in the current economic environment. In addition to increased demand, many of the markets in which TransAlta participates have established renewable portfolio targets or standards that require new renewable power investments.

As part of its balanced approach to capital allocation which includes returning capital to shareholders through dividends and share buybacks, TransAlta also has plans for investing in new capacity in its core markets where opportunities exist for renewable and cogeneration assets.

Alberta is Canada s fourth largest province by population with approximately 3.6 million residents representing approximately 11 per cent of Canada s total population. Alberta consumed approximately 70,000 GWh of electricity in 2008. As at December 31, 2008, the aggregate installed capacity of generating facilities in Alberta was approximately 12,300 MW.

Electrical utilities in the U.S. Pacific Northwest are organized into the Western Electricity Coordinating Council (WECC). The WECC is the largest geographically of the ten regions in the North American Electric Reliability Council and is divided into four sub regions, of which Region 1 includes British Columbia, Alberta, Washington, Oregon, Idaho, Montana, Utah, Western Wyoming and Northern Nevada. This sub region is referred to as the Northwest Power Pool (NWPP). The WECC estimates that approximately 369,000 GWh of electricity was consumed in the NWPP in 2008. The WECC also reported an estimated aggregate electrical generating capacity of approximately 85,000 MW in the NWPP for the year ending 2008.

Ontario is Canada s largest province with approximately 12.9 million residents representing approximately 39 per cent of Canada s total population. Ontario consumed approximately 148,700 GWh of electricity in 2008. Ontario Power Generation Inc., the successor to the generation business of Ontario s former integrated electric utility, controls two thirds of Ontario s approximately 32,000 MW of installed capacity, the balance of which is owned by municipal electric utilities and private independent power producers or industrial consumers.

In October 2004, the provincial government of New Brunswick officially opened the electricity market to partial competition and corporate reorganization. *The Electricity Act (2004)* allows wholesale and industrial consumers to purchase power from either New Brunswick Power or a competing supplier. The new competitive market does not extend to retail customers, businesses or small industries. In 2007, New Brunswick announced the Charter for Change requiring ten per cent of electricity purchases to be from renewable sources commencing in 2016.

The Corporation expects that the demand for electricity will continue to grow in its target markets over the long-term. In addition to increased demand, the market for electricity in some of these regions has undergone deregulation. Legislation in Alberta and Ontario and many states in the United States have mandated the unbundling of generation, transmission and distribution services which were traditionally provided by vertically integrated utilities to promote competition in the market for generation, which caused some integrated utilities to sell all or parts of their generation assets. While the pace of this process has changed, the Corporation believes that the combination of increased demand for electricity, deregulation and the increased availability of generation assets may provide an opportunity to increase its generation capacity and leverage its Commercial Operations Development capabilities, provided that in doing so, the financial position of the Corporation is not compromised.

Australia is heavily dependent on coal for electricity, more so than any other developed country except Denmark and Greece. About 80 per cent of power produced is derived from coal. Natural gas is increasingly used for electricity, especially in South Australia and Western Australia. The Australian Bureau of Agriculture and Resource Economics (ABARE) estimated total production of 272,000 GWh for 2008 with a growth rate of approximately 2.4 per cent per annum from 2009 to 2012. The major reform in the Australian electricity industry involved the establishment in southern and eastern Australia of the National Electricity Market (NEM). In Western Australia, where TransAlta s power assets are located, a new Wholesale Electricity Market (WEM) was introduced in late 2006. Total installed capacity in the WEM is about 4,500 MW, while TransAlta s capacity in the region is approximately 345 MW. TransAlta enjoys a solid competitive advantage in power supply to mining operations, especially remote mining operations, and has built up significant knowledge and expertise in this field.

Competitive Strengths

The Corporation believes it is well positioned to achieve its business strategy due to its competitive strengths, which include the following:

Financial strength - The Corporation has investment grade ratings from Moody s Investor Services, Inc. (**Moody s**), Standard & Poor s, a division of the McGraw Hill Companies, Inc. (**S&P**) and Dominion Bond Rating Service Limited (**DBRS**).

Stable cash flow base Approximately 70 per cent of the Corporation s generating capacity is contracted through PPAs or LTC s for the next five years. Revenues received under contractual arrangements are not subject to short-term fluctuations in the spot price for electricity.

Fuel diversity - The Corporation has a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, geothermal and wind. The Corporation believes that this mix reduces the impact on corporate performance in the event of external events affecting one fuel source.

Management team - The Corporation s management team has substantial industry, international and local market experience.

Commercial Operations Development expertise - The Corporation believes that its Commercial Operations Development group has enhanced returns from the Corporation s existing generation base and has allowed the Corporation to obtain more favourable pricing for uncommitted electricity, secure fuel supply on a cost-effective basis and fulfill electricity delivery obligations in the event of an outage.

Ownership or control of coal supply - The Corporation owns, controls or leases extensive coal reserves in Alberta that provide a long-term and stable source of fuel for all of its thermal generation capacity in Alberta. The Corporation s mines in Alberta contain some of the lowest sulphur coal in North America, averaging 0.25 per cent sulphur at the Whitewood mine and 0.25 per cent at the Highvale mine. Coal with lower sulphur content emits less sulphur dioxide when it is burned.

Wind Generation - The Corporation is one of the largest owners and operators of wind generation in Canada. The Wind management team has developed key relationships with customers, suppliers and policy makers that provide a competitive advantage in the development, operations and marketing of wind generation.

Environment The Corporation is a recognized leader in Sustainable Development and has taken early preventative action on a number of environmental fronts in advance of regulation.

Capital Expenditures

Capital expenditures for property and investments (including acquisitions) by TransAlta for the past five years were:

2008	$1,006.4 million	2005	$325.5 million
2007	$599.7 million	2004	$345.7 million
2006	$224.9 million		

ENVIRONMENTAL RISK MANAGEMENT

TransAlta is subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of electrical and thermal energy and surface mining. TransAlta is committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of its operations. TransAlta works with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

TransAlta s approach to managing its environmental, health and safety (**EHS**) risks has three elements:

- Compliance based activities, such as permitting and reporting;
- ISO based EHS Management systems and programs, such as safety programs and auditing; and
- Longer term strategic initiatives, including climate change and government policy development.

These elements are integrated into TransAlta s corporate wide operations and management systems. They are designed to mitigate risks of TransAlta s activities to employees, the public and the environment, and to address potential competitive risks from future changes in environmental policy. They are also supportive of TransAlta s corporate commitment to sustainability.

To meet regulatory requirements and improve environmental performance, TransAlta made environmental operating and capital expenditures in fiscal year 2008 of approximately $47 million. Environmental expenditures are generally defined as expenditures incurred to comply with Canadian or international environmental regulations, conventions or voluntary agreements.

All TransAlta s facilities are in material compliance with existing regulatory requirements. Environmental risk at the plants operated by TransAlta has been reduced by actions in several areas:

- Continued investment in mercury control technology evaluation leading to expected installation of mercury capture equipment at our Alberta coal plants in 2010, and at our Centralia, Washington coal plant by 2012;
- Uprate improvements delivering higher efficiency generation at the Sundance plant;
- Continued program of compliance and management system audits at all facilities;
- The planned decommissioning of the older Wabamun thermal plant in 2010;
- Acquisition of carbon offsets;
- Continued expansion of the wind energy business, with minimal emissions footprint; and
- Development of a carbon capture and storage demonstration project in Alberta.

On a longer time horizon, TransAlta anticipates future environmental regulatory developments in areas such as climate change, air quality and water. Regulatory changes and policy developments are tracked in all relevant jurisdictions. Relevant regulatory developments are discussed below.

Canada

On January 24, 2008, the Government of Alberta announced its long-term intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing carbon capture and storage technologies, developing conservation and energy efficiency programs, and through increased investment in clean energy technologies. We are assessing the impact of this proposal upon our operations and our own investment in environmental technologies and programs.

Alberta continues to maintain its greenhouse gas (**GHG**) regulatory regime which was implemented in July 1, 2007, under the *Climate Change and Emissions Management Amendment Act*. Under the legislation, baselines and targets for GHG intensity are set on a facility-by-facility basis. The legislation and subsequent regulations require a 12 per cent reduction in GHG emission intensity from a baseline of the average of 2003 to 2005 emission levels. 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 reduction requirements gradually increase until the eighth year by which time emissions must be 12 per cent below the established baseline. Emissions over the baseline must be mitigated either through contributions to an Alberta Technology Fund at $15 per tonne, or through the purchase and retirement of Alberta-based offsets from non-regulated sectors. 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 annual net compliance costs for 2008 are estimated to be $1.2 million.

Mercury reduction requirements in Alberta are established at a 70 per cent reduction by 2010. We submitted our mercury control plan in March 2007. Detailed mercury technology testing was conducted in 2008 and further is expected in 2009. Engineering work is underway to have mercury controls fully implemented in 2010.

On April 26, 2007, the Canadian government released details of its proposed environmental legislation in its Turning the Corner policy paper. 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 plan 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 of current levels. A number of material details in the federal plan are still to be determined, including its interaction with provincial programs, which would allow a reasonable determination of future compliance costs.

The Canadian government indicated in January 2009 that it intends to develop an integrated cap and trade program for greenhouse gas emissions, in cooperation with its North American trading partners. There are few details of this new approach and it is therefore not possible to determine what compliance costs would be or how it might affect the previous approach.

In August 2007, the Government of Ontario announced its climate change action plan which included a target to reduce GHG emissions by 6 per cent below 1990 level by 2014. Subsequently the government has indicated its intention to implement a cap and trade system for greenhouse gases by 2010, although no additional legislation or details have been developed.

United States

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect on July 22, 2007. Our 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.

On December 12, 2008, Washington State introduced draft legislation to enable a cap and trade system to be implemented by 2012. Specific details of caps and allocations will be developed in 2009. In parallel, Washington State is engaged with other western states in the Western Climate Initiative (**WCI**) to examine a regional cap and trade system for carbon. On September 23, 2008, the WCI released its design for a regional greenhouse gas cap and trade system, which will be influential in individual state regulation development. At this point, there are no indications as to how these initiatives will impact our fossil-fired assets in Washington.

The United States Federal Government continues to contemplate a number of proposed GHG related bills, but to date no clear outcome or schedule is evident. In February 2009, the Administration provided a budget plan for implementing an economy-wide federal cap & trade system to reduce greenhouse gases to 14 per cent below 2005 levels by 2020. The budget includes a plan to auction 100 per cent of the required allowances, with approximately $150B of the revenue raised from auctioning to be allocated to clean energy investments over 10 years.

TransAlta is an active participant in the Canadian Clean Power Coalition, which is committed to developing clean coal technology in Canada. The coalition has several engineering initiatives underway which will provide important guidance on ultimate clean coal solutions for TransAlta s facilities. The Corporation is also exploring the possibilities for a CO2 network pipeline through the ICON industry consortium.

In April 2008, TransAlta announced a partnership with Alstom LLC to develop a one million tonne/year carbon capture and storage project at one of TransAlta s coal-fired power stations in Alberta. This project has been shortlisted by the Alberta Government for contributory funding as part of the province s $2 billion CCS program, with a decision expected by June 30, 2009.

Environmental issues concerning water use are managed within the ISO 14001 framework. TransAlta continues to work with regulators in each jurisdiction in which it operates, to ensure water is used wisely on site and that all regulations pertaining to water and wetlands management, both on and off site, are met at all times.

TransAlta s environmental efforts have been recognized by the Dow Jones North American Sustainability Index for four years in a row. The Index represents the best environmental performance leaders in North America. In 2008, TransAlta also participated in the global Carbon Disclosure Project which requires detailed assessments of corporate climate change plans and actions.

To date, TransAlta does not believe that its competitive position in the wholesale generation business has been adversely affected by environmental concerns. TransAlta continues to make operational improvements and investments to its existing generating facilities to reduce the environmental impact of generating electricity.

RISK FACTORS

Readers should consider carefully the risk factors set forth below as well as the other information contained and incorporated by reference in this Annual Information Form. For a further discussion of risk factors affecting TransAlta, please refer to Risk Factors in the Annual MD&A, which is incorporated by reference herein.

A reference herein to a material adverse effect on the Corporation means such an effect on the Corporation on its business, financial condition, results of operations, or its cash flows, as the context requires.

Changes in the prices and availability of fuel supplies required to generate electricity, and in the price of electricity, may materially adversely affect the Corporation.

A significant portion of the Corporation s revenues are tied, either directly or indirectly, to the market price for electricity in the markets in which the Corporation operates. Market electricity prices are impacted by a number of factors, including: the price of fuel that is used to generate other sources of electricity (and, accordingly, certain of the factors that affect the price of fuel described below); the management of generation and the amount of excess generating capacity relative to load in a particular market; the cost of controlling emissions of pollution, including potentially the cost of carbon; the structure of the particular market; and weather conditions that impact electrical load. As a result, the Corporation cannot accurately predict future electricity prices and electricity price volatility could have a material adverse effect on the Corporation.

The Corporation buys natural gas and some of its coal to supply the fuel needed to generate electricity. The Corporation could be materially adversely affected if the cost of fuel that it must buy to generate electricity increases to a greater degree than the price that it can obtain for the electricity that it sells. Several factors affect the price of fuel, many of which are beyond the Corporation s control, including:

- prevailing market prices for fuel, including any associated transportation costs;
- demand for energy products;
- increases in the supply of energy products in the wholesale power markets; and
- the extent of fuel transportation capacity or cost of fuel transportation service into the Corporation s markets.

Changes in any of these factors may increase the Corporation s cost of producing power or decrease the amount of revenue it receives from the sale of power, which could materially adversely affect the Corporation.

The rules and regulations in the various markets in which the Corporation operates are subject to change, which may materially adversely affect the Corporation.

Certain of the markets in which the Corporation operates and intends to operate are subject to significant regulatory oversight and control. The Corporation is not able to predict whether there will be any further changes in the regulatory environment, including potential regulation of the rates allowed to be charged and the capital structure of wholesale generating companies such as the Corporation, or what the ultimate effect of a changing regulatory environment will have on its business. Existing market rules and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Corporation or its facilities which could have a material adverse effect on the Corporation. The Corporation cannot guarantee that it will be able to adapt its business in a timely manner in response to any changes in the regulatory regimes in which it operates, and such failure to adapt could have a material adverse effect on the Corporation.

Regulatory authorities may also from time to time investigate the Corporation s activities in the markets in which it operates or pursues trading. Such investigations may result in sanctions or penalties which may materially affect the Corporation s future activities or financial status.

The Corporation s facilities are also subject to various licensing and permitting requirements in the jurisdictions in which they operate, many of which licenses and permits need to be renewed from time to time. If the Corporation is unsuccessful in renewing such licenses or permits, or the terms of such licenses or permits are changed in a manner that is adverse to the Corporation, the Corporation could be materially adversely affected.

Any changes in the rules and regulations of provincial or state public utility commissions or other regulatory bodies in the other markets in which the Corporation competes or may compete in the future may materially adversely affect the Corporation.

Many of the Corporation s activities and properties are subject to environmental requirements and changes in, or liabilities under, these requirements may materially adversely affect the Corporation.

The Corporation s operations are subject to extensive Canadian, United States and other federal, provincial, state and local environmental laws, regulations and guidelines, relating to the generation and transmission of electrical and thermal energy and surface mining, pertaining to pollution and protection of the environment, health and safety and governing among other things, air emissions, water usage and discharges, storage, treatment and disposal of waste and other materials and remediation of sites and land use responsibility (collectively, environmental regulation). These laws can impose liability for costs to investigate and remediate contamination without regard to fault and under certain circumstances liability may be joint and several resulting in one responsible party being held responsible for the entire obligation. Environmental regulation can also impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transport, treatment and disposal of hazardous substances and waste and can impose clean-up, disclosure or other responsibilities with respect to spills, releases and emissions of various substances to the environment. Environmental regulation can also require that facilities and other properties associated with the Corporation s operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, there is an increasing level of environmental regulation regarding the use, treatment and discharge of water and increasing anticipation of new or additional emission regulations at a national level in Canada and the United States which may impose different compliance requirements standards on the Corporation. These various compliance standards may result in duplicate compliance and costs requirements for the Corporation or may impact our ability to operate our facilities.

To comply with environmental regulation, the Corporation must incur material capital and operating expenditures relating to environmental monitoring, emissions and effluent control equipment and processes, emissions measurement, verification and reporting, emissions fees and other compliance activities or obligations. The Corporation expects to continue to have environmental expenditures in the future. Stricter standards, new or greater regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Corporation subject to environmental regulation and the implementation of provincial, state and national GHG emissions, mercury emissions or other air emissions regulation in a jurisdiction in which we operate could increase the amount of these expenditures. To the extent these expenditures cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs (as defined herein) or otherwise, the costs to the Corporation could be material. In addition, compliance with environmental regulation might result in restrictions on some of the Corporation s operations. If the Corporation does not comply with environmental regulation, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on the Corporation or to curtail its operations and significant expenditures on compliance, new equipment or technology, reporting obligations and research and development. In addition to environmental regulation, the Corporation could also face civil liability in the event that private parties seek to impose liability on the Corporation for property damage, personal injury or other costs and losses. The Corporation cannot guarantee that lawsuits or administrative or investigative actions will not be commenced against it otherwise affect its operations and assets. If an action is filed against the Corporation or which may otherwise affect its operations and assets, the Corporation could be required to make substantial expenditures to defend or evidence its activities or to bring the Corporation, its operations and assets into compliance, which could have a material adverse effect on the Corporation.

A number of recent federal, provincial, state and local regulatory efforts continue to focus on potential climate change or GHG emissions regulation. GHG legislation is in early stages of evolution in Canada and the United States, and it is relatively early to determine the impact of potential GHG reduction requirements. For example, the issues of jurisdiction to regulate GHG emissions, as between the federal and provincial governments, and whether both levels of government will be able to agree on harmonization of desired GHG emissions reduction requirements, also remains outstanding in Canada. In addition, Washington is part of a group of states in the Western Climate Initiative, which have announced the intention to implement a cap and trade program for GHGs by 2012. Mandatory GHG emissions reductions requirements are expected to impose increased costs on the Corporation, as is expected to be the case generally for thermal power producers in North America. The Corporation is subject to other air quality regulation including mercury regulation. At this time, the Corporation cannot assess the potential impact of future mercury regulation at its United States facilities. To the extent new or additional GHG, mercury or other air emission regulations may require the Corporation to incur costs that cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs or otherwise, the costs could be material and have a material adverse effect on the Corporation.

The Corporation s surface mining operations are subject to laws and regulations establishing mining, environmental protection and reclamation standards for all aspect of surface mining. As a mine owner or operator the Corporation must obtain permits from the applicable regulatory body providing for the authorization of certain mining operations that result in a disturbance of the surface. These requirements seek to limit the adverse impacts of coal mining and more restrictive requirements may be adopted from time to time. TransAlta as a mine owner or operator may also be required to submit a bond or otherwise secure payment of certain long-term obligations including mine closure or reclamations costs. Surety bond costs have increased in recent years while the market terms of such bonds have generally become more unfavourable. In addition, the number of companies willing to issue surety bonds has decreased. TransAlta could be required to self fund these obligations should it be unable to renew or secure the required surety bonds for its mining operations.

Changes in general economic conditions may have a material adverse effect on the Corporation.

Adverse changes in general economic and market conditions could negatively impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, credit risk, and counterparty risk, which could have a material adverse effect on the Corporation. Changes in interest rates can impact the Corporation s borrowing costs and the capacity revenues the Corporation receives pursuant to the Alberta government mandated power purchase arrangements (the **Alberta PPAs**).

Under the government mandated power purchase arrangements pursuant to which the Corporation operates most of its facilities in Alberta, the Corporation is subject to certain risks, including the possibilities of penalties for unplanned outages and the burden of increased costs required to maintain and operate its generation facilities.

The majority of the Corporation s Alberta coal fired and hydroelectric generating plants operate under the Alberta PPAs which established committed capacity and electrical energy generation requirements and availability targets to be achieved by each coal fired plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which power will be supplied. Under the Alberta PPAs applicable to coal fired plants, in the event of an unplanned outage, other than an outage determined to be caused by force majeure, the Corporation must pay a penalty for the lost production based upon a price equal to the 30 day trailing average of Alberta market electricity prices. Consequently, an unplanned outage could have a material adverse effect on the Corporation.

The Corporation bears some of the impact of increases in its operating costs (other than increases arising as a result of a change of law as such term is defined in the Alberta PPAs) because the price at which the Corporation is able to sell its generation under the Alberta PPAs is based on a schedule of forecast fixed costs. Many of the forecast costs will be determined by indices, formulae or other means for the entire term of the Alberta PPA. The Corporation s actual results will vary and depend on performance compared to the forecasts on which the Alberta PPAs are based. Operating costs could increase as a result of a number of factors which are beyond the Corporation s control. A significant increase in the Corporation s operating costs could have a material adverse effect on the Corporation.

From time to time during the term of the Alberta PPAs, issues may arise regarding the intended operation of the Alberta PPAs which may require certain provisions of the Alberta PPAs to be interpreted, and the interpretations given may not be favourable to the Corporation. In such circumstances, the Corporation could be materially adversely affected.

The operation and maintenance of the Corporation s facilities involves risks that may materially adversely affect the Corporation.

The operation, maintenance, refurbishment, construction and expansion of power generation facilities involve risks, including breakdown or failure of equipment or processes, fuel interruption and performance below expected levels of output or efficiency. Certain of the Corporation s generation facilities, particularly in Alberta, were constructed many years ago and may require significant capital expenditures to maintain peak efficiency or to maintain operations at all. In addition, weather related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of the Corporation s facilities and may materially adversely affect the Corporation.

The Corporation has entered into on going maintenance and service agreements with the manufacturers of certain critical equipment. If a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support, the Corporation may have to enter into alternative arrangements with other providers if it cannot perform the maintenance itself. These arrangements could be more expensive to the Corporation than its current arrangements and this increased expense could have a material adverse effect on the Corporation. If the Corporation is unable to enter into satisfactory alternative arrangements, the inability of the Corporation to access technical expertise or parts could have a material adverse effect on the Corporation.

While the Corporation maintains an inventory, or otherwise makes arrangements to obtain, spare parts to replace critical equipment and maintains insurance for property damage to protect against operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties which could result if the Corporation is unable to operate its generation facilities at a level necessary to comply with sales contracts (including Alberta PPAs).

The Corporation may be subject to the risk that it is necessary to operate a plant at a capacity level beyond that which the Corporation has contracted to provide steam in order to fulfill a contract. In such circumstances the costs to produce the steam being sold may exceed the revenues derived therefrom.

The Corporation relies on transmission lines that it does not own or control, which may hinder its ability to deliver electricity.

The Corporation depends on transmission and distribution facilities that are owned and operated by utilities and other power companies to deliver the electricity the Corporation generates. An extended disruption in transmission would impact the Corporation s ability to sell and deliver electricity, which could have a material adverse effect on the Corporation.

The Corporation may be adversely affected if its supply of water is materially reduced.

Hydroelectric, natural gas, and coal-fired plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to the Corporation s facilities. Any material reduction in the water flow to the Corporation s facilities would limit the Corporation s ability to produce and market electricity from these facilities and could have a material adverse effect on the Corporation. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in Alberta. Any such change in regulations could have a material adverse effect on the Corporation.

Trading risks may have a material adverse affect on the Corporation.

The Corporation s trading and marketing business frequently involves the establishment of trading positions in the wholesale energy markets on both a long term and short term basis. To the extent that the Corporation has long positions in the energy markets, a downturn in the markets is likely to result in losses from a decline in the value of such long positions. Conversely, to the extent that the Corporation enters into forward sales contracts to deliver energy the Corporation does not own, or take short positions in the energy markets, an upturn in the energy markets is likely to expose the Corporation to losses as it attempts to cover any short positions by acquiring energy in a rising market.

In addition, from time to time the Corporation may have a trading strategy consisting of simultaneously holding a long position and a short position, from which the Corporation expects to earn a profit based on changes in the relative value of the two positions. If, however, the relative value of the two positions changes in a direction or manner the Corporation did not anticipate, it could realize losses from such a paired position.

If the strategy the Corporation uses to hedge its exposures to these various risks is not effective, it could incur significant losses. The Corporation s trading positions are subject to the level of volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect the Corporation s positions which could also have a material adverse effect on the Corporation.

While the Corporation uses a number of risk management controls to limit its exposure to risks arising from its trading activities, including value-at-risk, volumetric and term limits and restrictions on authorized instruments, the Corporation cannot guarantee that losses will not occur and such losses, if material, could have a material adverse effect on the Corporation.

Because of the Corporation s multinational operations, the Corporation is subject to currency rate risk and regulatory and political risk.

A significant part of the Corporation s revenues and expenditures are in U.S. and other currencies. Fluctuations in the exchange rate between these currencies and the Canadian dollar could have a negative effect on the Corporation. While the Corporation attempts to manage this risk through its use of hedging instruments, including cross currency swaps, forward exchange contracts and by matching revenues and expenses by currency at the Corporate level, fluctuations in these exchange rates may have a material adverse effect on the Corporation.

In addition to currency rate risk, the Corporation s foreign operations may be subject to regulatory and political risk. Any change to the regulations governing power generation or the political climate in countries where the Corporation has operations could impose additional costs and have a material adverse effect on the Corporation.

The Corporation may have difficulty raising needed capital in the future, which could significantly harm its business.

To the extent that the Corporation s sources of cash and cash flow from operations are insufficient to fund the Corporation s activities, it may need to raise additional funds. Additional financing may not be available when needed and, if such financing is available, it may not be available on terms favourable to the Corporation.

The Corporation s debt securities will be structurally subordinated to any debt of its subsidiaries that is currently outstanding or may be incurred in the future.

The Corporation operates its business through, and a majority of its assets are held by, its subsidiaries, including partnerships. The Corporation s results of operations and ability to service indebtedness are dependent upon the results of operations of its subsidiaries and the payment of funds by these subsidiaries to it in the form of loans, dividends or otherwise. The Corporation s subsidiaries will not have an obligation to pay amounts due pursuant to any debt securities issued by the Corporation or make any funds available for payment of debt securities issued by the Corporation, whether by dividends, interests, loans, advances or other payments. In addition, the payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions.

In the event of the liquidation of any subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used to pay the Corporation s indebtedness, including any debt securities issued by the Corporation. Such indebtedness and any other future indebtedness of such subsidiaries would be structurally senior to any debt securities issued by the Corporation.

The Corporation s subsidiaries have financed some investments using non recourse project financing. Each non recourse project loan is structured to be repaid out of cash flow provided by the investment. In the event of a default under a financing agreement which is not cured, the lenders would generally have rights to the related assets. In the event of foreclosure after a default, the Corporation s subsidiary may lose its equity in the asset or may not be entitled to any cash that the asset may generate. Although a default under a project loan will not cause a default with respect to any debt securities issued by the Corporation, it may materially affect the Corporation s ability to service its outstanding indebtedness.

Certain of the contracts to which the Corporation is a party require the Corporation to provide collateral against its obligations.

The Corporation is exposed to risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of hedges and proprietary trading. The terms and conditions of these contracts require the Corporation to provide collateral when the fair value of these contracts is in excess of any credit limits granted by the Corporation s counterparties and the contract obliges the Corporation to provide the collateral. The change in fair value of these contracts occurs due to changes in commodity prices. These contracts include: (i) purchase agreements, when forward commodity prices are less than contracted prices; and (ii) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in the Corporation s creditworthiness by certain credit rating agencies may decrease the credit limits granted by the Corporation s counterparties and accordingly increase the amount of collateral the Corporation may have to provide.

If counterparties to the Corporation s contracts are unable to meet their obligations, the Corporation may be materially adversely affected.

If purchasers of the Corporation s electricity, steam or other contractual counterparties of the Corporation default on their obligations, the Corporation may be materially adversely affected. While the Corporation seeks to control its exposure to credit risk by considering the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, the Corporation cannot guarantee that it will be successful in identifying credit worthy customers. Moreover, while the Corporation seeks to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, it cannot guarantee that it will be successful in doing so. If counterparties to the Corporation s contracts are unable to meet their obligations, the Corporation could suffer a reduction in revenue which could have a material adverse effect on the Corporation.

Insurance coverage may not be sufficient.

The Corporation has insurance for its facilities, including all risk property insurance, commercial general public liability insurance, boiler and machinery coverage, replacement power and business interruption insurance, in amounts and with deductibles that the Corporation considers appropriate. The Corporation s insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for any loss of or any damage to any of its generation facilities may not be sufficient to permit it to continue to make payments on its debt.

Provision for income taxes may not be sufficient.

The Corporation s operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. In addition, the Corporation s tax filings are subject to audit by taxation authorities. While the Corporation believes that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, the Corporation cannot guarantee that it will not have disagreements with the Canada Revenue Agency or other taxation authorities with respect to the Corporation s tax filings.

The Corporation may be unsuccessful in the defence of legal actions.

The Corporation is occasionally named as a defendant in various claims and legal actions. There can be no assurance that the Corporation will be successful in the defence of each of these claims and legal actions or that any claim or legal action that is decided adverse to the Corporation will not materially adversely affect the Corporation.

If the Corporation fails to attract and retain key personnel, it could be materially adversely affected.

The loss of any of the Corporation s key personnel or its inability to attract, train, retain and motivate additional qualified management and other personnel could have a material adverse effect on the Corporation. Competition for these personnel is intense and there can be no assurance that the Corporation will be successful in this regard.

If the Corporation is unable to successfully negotiate new collective bargaining agreements with its unionized workforce, as required from time to time, it will be adversely affected.

While the Corporation believes it has a good relationship with its unionized employees, the Corporation cannot guarantee that it will be able to successfully negotiate or renegotiate its collective bargaining agreements on terms agreeable to the Corporation. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on the Corporation.

EMPLOYEES

As of December 31, 2008, the Corporation had 2,110 full and part-time employees, of which 1,529 were employed in TransAlta s generation business and 147 were employed in TransAlta s energy marketing business. Approximately 46 per cent of the Corporation s employees are represented by labour unions. The Corporation is currently a party to 11 different collective bargaining agreements. Overall in 2008, the Corporation renewed three of the agreements, an additional five agreements are expected to be re-negotiated in 2009, and the remaining three agreements are expected to be re-negotiated in 2010.

CAPITAL STRUCTURE

General

The Corporation s authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. As at March 12, 2009, there were 197,849,306 common shares outstanding and no first preferred shares were outstanding.

Common Shares

Each common share of the Corporation entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Corporation, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board of Directors, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of the assets of the Corporation upon a liquidation, dissolution or winding up and subject to prior rights and privileges attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

First Preferred Shares

The Corporation is authorized to issue an unlimited number of first preferred shares, issuable in series and, with respect to each series, the Board of Directors is authorized to fix the number of shares comprising the series and determine the designation, rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

The first preferred shares of all series rank senior to all other shares of the Corporation with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board of Directors at the rate established by the Board of Directors at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of the Corporation unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of the Corporation until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares to the date of such liquidation, dissolution, winding up, or reduction of stated capital, as applicable. After payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of the assets of the Corporation.

The Corporation s Board of Directors may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon the Corporation failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board of Directors then consists of less than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Subject to the share conditions attaching to any particular series providing to the contrary, the Corporation may redeem first preferred shares of a series, in whole or from time to time in part, at the redemption price applicable to each series and the Corporation has the right to acquire any of the first preferred shares of one or more series by purchase for cancellation in the open market or by invitation for tenders at a price not to exceed the redemption price applicable to the series.

CREDIT RATINGS

Issuer Rating

As of December 31, 2008, the Corporation s issuer rating from S&P was BBB (stable), from Moody s was Baa2 (stable), and from DBRS was BBB (stable).

Senior Unsecured Long Term Debt

As of December 31, 2008, the Corporation s senior unsecured long-term debt is rated BBB (stable) by DBRS, BBB (stable) by S&P and Baa2 (stable) by Moody s. The ratings for debt instruments range from a high of AAA to a low of D in the case of both DBRS and S&P and from a high of Aaa to a low of C in the case of Moody s.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is more susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. High or Low grades indicate the relative standing within a rating category. DBRS also assigns rating trends to each of its ratings to give investors an understanding of DBRS opinion regarding the outlook for the rating in question.

According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on such obligations than on obligations in the higher rating categories. The ratings from AA to B may be modified by the addition of a plus (+) or minus ( ) sign to show relative standing within the major rating categories.

According to the Moody s rating system, debt securities rated Baa are subject to moderate credit risk. They are considered medium grade and as such may possess certain speculative characteristics. Numerical modifiers 1, 2 and 3 are applied to each rating category, with 1 indicating that the obligation ranks in the higher end of the category, 2 indicating a mid range ranking and 3 indicating a ranking in the lower end of the category.

Note Regarding Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Corporation s outstanding securities by S&P, Moody s and DBRS, as applicable, are not recommendations to purchase, hold or sell such securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by S&P, Moody s or DBRS in the future if, in its judgement, circumstances so warrant.

DIVIDENDS

In setting its dividend, TransAlta s Board of Directors considers the Corporation s financial performance and balances liquidity requirements, capital reinvestment and returning capital to shareholders, with a policy of paying annual dividends to its shareholders in the range of 60 to 70 per cent of comparable earnings. The payment and level of future dividends on the common shares are determined by the Board of Directors of TransAlta upon consideration of such factors. TransAlta has declared and paid the following dividends per share on its outstanding common shares for the past three years:

Period		Dividend per Common Share
2006	First Quarter	$0.25
	Second Quarter	$0.25
	Third Quarter	$0.25
	Fourth Quarter	$0.25
2007	First Quarter	$0.25
	Second Quarter	$0.25
	Third Quarter	$0.25
	Fourth Quarter	$0.25
2008	First Quarter	$0.27
	Second Quarter	$0.27
	Third Quarter	$0.27
	Fourth Quarter	$0.27

On January 29, 2009, the Corporation s Board of Directors declared a cash dividend of $0.29 per common share, payable on April 1, 2009 to shareholders of record on March 1, 2009.

MARKET FOR SECURITIES

TransAlta s common shares are listed on the TSX under the symbol TA and the New York Stock Exchange under the symbol TAC . The following table sets forth the reported high and low trading prices and trading volumes of the Corporation s common shares as reported by the TSX for the periods indicated:

	Price ($)		
Month	**High**	**Low**	**Volume**
2008			
January	34.00	29.85	15,201,560
February	35.80	32.01	27,280,079
March	35.73	30.03	31,739,588
April	34.27	30.83	16,237,231
May	36.16	33.24	16,671,590
June	37.30	34.65	17,308,802
July	38.10	30.71	42,637,530
August	37.73	34.59	20,057,372
September	36.88	26.53	28,180,867
October	29.85	20.00	24,458,282
November	24.59	21.00	14,517,240
December	24.45	20.77	11,835,571
2009			
January	26.60	21.13	10,881,392
February	22.96	18.50	16,191,905
March 1 to 12	21.05	17.96	5,609,514

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of the directors and officers of TransAlta as at March 12, 2009, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve to the Board is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
William D. Anderson Ontario, Canada	2003	*Corporate Director*. Mr. Anderson was President of BCE Ventures (a subsidiary of BCE Inc.) from 2001 to 2005 (telecommunications) and prior to that Chief Financial Officer (CFO) of BCE Inc., Bell Canada Inc. and Bell Cablemedia plc (telecommunications). As President of BCE Ventures, he was responsible for a number of significant operating companies as well as being Chief Executive Officer (CEO) of Bell Canada International Inc. In his CFO roles, Mr. Anderson was responsible for all financial operations of the respective companies and executed numerous debt and equity financings, corporate acquisition and disposition transactions as well as corporate and operational restructurings. Mr. Anderson is a director of Gildan Activewear Inc. and of MDS Inc. He is a past director at BCE Emergis Inc., Bell Cablemedia plc, Bell Canada International Inc., CGI Group Inc., Four Seasons Hotels Inc., Sears Canada Inc., and Videotron Holdings plc. At TransAlta, Mr. Anderson is Chair of the Audit and Risk Committee of the Board. Mr. Anderson holds a bachelor degree in business administration from the University of Western Ontario (London, ON) and is a Chartered Accountant.
Stephen L. Baum New Hampshire, U.S.A.	2008	*Corporate Director*. Mr. Baum was Chairman and CEO of Sempra Energy from December 1996 to February 2006, a San Diego-based Fortune 500 energy services holding company formerly known as Enova Corporation. Previous to that, Mr. Baum was President, CEO and Vice-Chairman of Sempra Energy. Prior to that he was Chairman, CEO and a member of the board of directors of Enova Corporation, the parent company of San Diego Gas & Electric (SDG&E) where he served in various officer positions including General Counsel. Before joining SDG&E, he was Senior Vice President and General Counsel of the New York Power Authority. He has also held various legal positions, including General Attorney at Orange & Rockland Utilities, and as an associate with the law firm of Curtis, Mallet-Prevost, Colt & Mosle in New York City. ***Mr. Baum is a member of the board of directors of Computer Science Corporation and is Chair of its Audit Committee. He is also a Senior Advisor to SkyFuel Inc., a solar company.*** ***At TransAlta, Mr. Baum is a member of the Audit and Risk Committee and the Human Resources Committee of the Board.*** ***Mr. Baum is a graduate of Harvard University and the University of Virginia Law School. He has also served as a Captain in the U.S. Marine Corps.***
Stanley J. Bright (1)	1999	

Maryland, U.S.A.

Corporate Director. Mr. Bright was President, CEO and Chairman of MidAmerican Energy Company (MidAmerican) from 1997 to 1999 (electric and gas utility). He was also Chairman, President, and CEO, and CEO of predecessor companies, including the Iowa-Illinois Gas & Electric Company (IIG&E) from 1991 to 1997. As the CEO of IIG&E, Mr. Bright was successful with the consolidation of IIG&E and other Iowa based utilities in anticipation of emerging market competition, giving rise to the creation of MidAmerican. As the Chairman, President and CEO of the new entity, Mr. Bright led the realization of significant synergies while working through the post-merger transition. The Company also structured a long-term rate plan with the Iowa Public Service Commission. He retired as CEO of MidAmerican in 1999 but continued as a director until 2006.

At TransAlta, Mr. Bright is Chair of the Human Resources Committee of the Board.

Mr. Bright holds an undergraduate degree in accounting from The George Washington University (Washington, DC) and is a Certified Public Accountant.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Timothy W. Faithfull England, U.K.	2003	***Corporate Director***. Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc (energy), where he filled diverse international roles principally in oil products and LNG project development. As President and CEO of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line, the first fully integrated oil sands venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operations of Shell International Trading and Shipping Company from 1993 to 1996. He was Chairman and CEO of Shell Eastern Petroleum in Singapore from 1996 to 1999, including Shell s main refinery and oil products trading for Asia Pacific. During his time in Singapore he was a director of DBS Bank, and the Port of Singapore Authority. He was a trustee of the main Singapore Arts/Theatre complex. In Calgary, he served on the board of the Calgary Health Trust and the Epcor Arts Centre. Mr. Faithfull is a director of Canadian Pacific Railway Limited, Shell Pension Trust Limited, AMEC plc and Enerflex Systems Income Fund. At TransAlta, Mr. Faithfull is a member of the Audit and Risk Committee and the Human Resources Committee of the Board. Mr. Faithfull holds a master of arts degree in philosophy, politics and economics from the University of Oxford, U.K.
Ambassador Gordon D. Giffin Georgia, U.S.A	2002	***Lawyer and Senior Partner, McKenna, Long & Aldridge LLP*** *(attorneys)*. From 1997 to 2001, Mr. Giffin served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy. Prior to this appointment, he practised law for 18 years as a senior partner in Atlanta, Georgia and Washington, D.C. His practice focused on energy regulatory work at the state and federal levels. Prior to that, he served as Chief Counsel and Legislative Director to United States Senator Sam Nunn, with responsibility for the legal and legislative operations of the office. In 2001, Mr. Giffin returned to private practice where he specialized in state and federal regulatory matters, including those related to trade, energy and trans-border commerce. Mr. Giffin is a director of Canadian Imperial Bank of Commerce, Canadian National Railway Company, Canadian Natural Resources Limited, and Ontario Energy Savings Ltd. At TransAlta, Mr. Giffin is Chair of the Governance and Environment Committee of the Board. Mr. Giffin holds a bachelor of arts from Duke University (Durham, NC) and a juris doctorate from Emory University School of Law (Atlanta, GA).

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
C. Kent Jespersen Alberta, Canada	2004	***Corporate Director***. Mr. Jespersen has been Chair and CEO of La Jolla Resources International Ltd. since 1998 (advisory and investments). He has also held senior executive positions with NOVA Corporation of Alberta, Foothills Pipe Lines Ltd., and Husky Oil Limited before assuming the presidency of Foothills Pipe Lines Ltd. and later, NOVA Gas International Ltd. (NOVA). At NOVA, he led the non-regulated energy services business (including energy trading and marketing) and all international activities. Mr. Jespersen is Chairman and a director of Orvana Minerals Ltd. and CCR Technologies Ltd. and a director of Matrikon Inc., Axia NetMedia Corporation and CanElson Drilling Ltd. At TransAlta, Mr. Jespersen is a member of the Governance and Environment Committee and the Human Resources Committee of the Board. Mr. Jespersen holds a bachelor of science in education and a master of science in education from the University of Oregon (Eugene, OR).
Michael M. Kanovsky Alberta, Canada	2004	***Corporate Director and Independent Businessman***. Mr. Kanovsky co-founded Northstar Energy Corporation (Northstar) with initial capital of $400,000 and helped build this entity into an oil and gas producer that was sold to Devon Energy Corporation for approximately $600 million in 1998. During this period, Mr. Kanovsky was responsible for strategy and finance as well as merger and acquisition activity. He initiated Northstar s entry into electrical cogeneration through its wholly-owned power subsidiary, Powerlink Corporation (Powerlink). Powerlink developed one of the first independent power producer (IPP) gas-fired co-generation plants in Ontario and also internationally. In 1997, he founded Bonavista Energy Trust, which has grown to a present day market capitalization of approximately $2 billion. Mr. Kanovsky is a director of Argosy Energy Corporation, ARC Energy Trust, Bonavista Energy Trust, Devon Energy Corporation, and Pure Technologies Ltd. At TransAlta, Mr. Kanovsky is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board. Mr. Kanovsky, a Professional Engineer, holds a bachelor of science in mechanical engineering from Queen s University (Kingston, ON) as well as a master of business administration from the Richard Ivey School of Business at the University of Western Ontario (London, ON).
Donna Soble Kaufman Ontario, Canada	1989	***Lawyer and Corporate Director***. Mrs. Kaufman is a former partner with Stikeman Elliott LLP, an international law firm, where she practised antitrust law. She has served on a number of boards since 1987, when she became a director of Selkirk Communications Limited, a diversified communications company. A year later she was appointed Chair of the Board, President and CEO. Several other directorships followed. In addition to TransAlta, Mrs. Kaufman currently serves on the boards of BCE Inc. and Bell Canada. She is also a director of HISTORICA, a private-sector education initiative, of the Institute of Corporate Directors, and a member of the Canadian Advisory Board of Catalyst, a non-profit organization working to advance women in business. In 2001, she was named a Fellow of the Institute of Corporate Directors. At TransAlta, Mrs. Kaufman is Chair of the Board and an ex-officio member of all committees of the Board.

Mrs. Kaufman holds a bachelor of civil law degree from McGill University (Montréal, QC) and a master of laws degree from the Université de Montréal (Montréal, QC).

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Gordon S. Lackenbauer (1) Alberta, Canada	2005	***Corporate Director***. Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. (investment banking) from 1990 to 2004. Prior to this, he was responsible for the principal activities of the firm, which included fixed income sales and trading, new issue underwriting, syndication and merger and acquisition advisory mandates. Mr. Lackenbauer has worked with many of Canada s leading utilities and has frequently acted as an expert financial witness testifying on the cost of capital, appropriate capital structure, and the fair rate of return, principally before the Alberta Utilities Commission, the National Energy Board, and the Ontario Energy Board. Mr. Lackenbauer is a director of NAL Oil & Gas Trust and CTV Globemedia Inc. At TransAlta, Mr. Lackenbauer is a member of the Governance and Environment Committee and the Audit and Risk Committee of the Board. Mr. Lackenbauer holds a bachelor of arts in economics from Loyola College (Montréal, QC), as well as a master of business administration from the University of Western Ontario (London, ON). He is also a chartered financial analyst.
Martha C. Piper British Columbia, Canada	2006	***Corporate Director***. Dr. Piper was President and Vice-Chancellor of the University of British Columbia from 1997 to 2006 (education). Prior to her appointment at UBC, she served as Vice-President, Research at the University of Alberta. She served on the boards of the Alberta Research Council, the Conference Board of Canada and the Centre of Frontier Engineering Research. Dr. Piper was also appointed by the Prime Minister of Canada to the Advisory Council on Science and Technology and currently Chairs the Board of the National Institute for Nanotechnology. Dr. Piper is a director of the Bank of Montreal, Shoppers Drug Mart Corporation and a member of the Canadian delegation to the Trilateral Commission, an organization fostering closer cooperation among the core democratic industrialized areas of the world. At TransAlta, Dr. Piper is a member of the Human Resources Committee and the Governance and Environment Committee of the Board. Dr. Piper holds a bachelor of science in physical therapy from the University of Michigan (Ann Arbor, MI), a master of arts in child development from the University of Connecticut (Storrs, CT), and a doctorate of philosophy in epidemiology and biostatistics from McGill University (Montréal, QC). She has also received honorary degrees from 16 international universities. Dr. Piper is an Officer of the Order of Canada and a recipient of the Order of British Columbia.
Luis Vázquez Senties Mexico	2001	***Corporate Director and Independent Businessman***. Mr. Vázquez is founder, President, CEO and Chairman of Grupo Diavaz, an international constructor of offshore oil and gas platforms, developer of oil and gas fields, and a distributor of natural gas in Mexico (oil and gas). Grupo Diavaz began as a Mexican underwater diving

operation that grew to become the world s second largest firm of its kind, servicing the offshore oil and gas industry in both exploration and production efforts.

Mr. Vázquez is Chairman of the Mexican Gas Association and Vice-President of the Mexico Chapter of the World Energy Council. He is a past director of the American Gas Association.

At TransAlta, Mr. Vázquez is a member of the Human Resources Committee of the Board.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Stephen G. Snyder Alberta, Canada	1996	***President and Chief Executive Officer of TransAlta Corporation since 1996.*** Previously Mr. Snyder was President & CEO, Noma Industries Ltd., President & CEO, GE Canada Inc., and President & CEO, Camco, Inc. Mr. Snyder is a director of the Canadian Imperial Bank of Commerce, Chair of the Calgary Stampede Foundation, and Chair of the Alberta Secretariat for Action on Homelessness. He is past-chair of the Calgary Committee to End Homelessness, the Canada-Alberta ecoEnergy Carbon Capture & Storage Task Force, the Conference Board of Canada, the Canadian Electricity Association, the Calgary Zoological Society, the University of Calgary Management Advisory Council, the Calgary Zoo Destination Africa Campaign and the Calgary United Way Campaign. Mr. Snyder holds a bachelor of science in chemical engineering from Queen s University (Kingston, ON) as well as a master of business administration from the University of Western Ontario (London, ON). He has honourary degrees from the University of Calgary (LLD), and the Southern Alberta Institute of Technology (Bachelor of Applied Technology). He was awarded the Alberta Centennial Medal in 2005, and the Conference Board Honorary Associate Award for 2008.

Notes:

(1) Mr. Bright served as a director of Access Air Inc. (Access Air) for the period of December 4, 1997 to January 31, 2000, a privately held start-up airline company. The company Mr. Bright was employed by, and whom he represented on the Access Air board, supported Access Air in the hope that it would improve air service to the state of Iowa. Access Air filed for bankruptcy protection on November 29, 1999.

(2) Mr. Lackenbauer resigned from the Board of Directors of Tembec Inc. (Tembec) on August 2, 2007. On December 19, 2007, Tembec announced its proposed recapitalization transaction providing a consensual solution to both noteholders and shareholders. On February 22, 2008, Tembec announced that it had received the approval of the majority of shareholders and the requisite majority of noteholders of Tembec Industries Inc. On February 27, 2008, Tembec announced that it had received approval from the Ontario Superior Court of Justice (Commercial List) with respect to their plan of arrangement relating to the proposed recapitalization transaction. On October 31, 2008, Tembec announced that it had successfully obtained a final American court order recognizing its Canadian plan of arrangement as a foreign proceeding in the United States.

Officers

Name	Principal Occupation	Residence
Stephen G. Snyder	President and Chief Executive Officer	Alberta, Canada
Brian Burden	Executive Vice-President and Chief Financial Officer	Alberta, Canada
William D.A. Bridge	Executive Vice-President, Generation Technology and PMM	Alberta, Canada
Dawn L. Farrell	Executive Vice-President, Commercial Operations and Development	Alberta, Canada
Richard P. Langhammer	Executive Vice-President, Generation Operations	Alberta, Canada
Kenneth S. Stickland	Executive Vice-President, Legal, SD and EH&S	Alberta, Canada
Michael Williams	Executive Vice-President, Human Resources, IT and Communications	Alberta, Canada
Frank Hawkins	Vice-President and Treasurer	Alberta, Canada
Maryse C. St.-Laurent	Corporate Secretary	Alberta, Canada

All of the officers of TransAlta have held their present principal occupation or position for the past five years, except for the following:

- Prior to December 2005, Brian Burden was Executive Vice-President and Chief Financial Officer of Molson Inc. Prior to 2002, he was Senior Vice-President, Seagram Corporate/Venture Transition of Diageo PLC.

- Prior to July 2007, William Bridge was Vice-President, Western Canada Operations. Prior to October 2005, Mr. Bridge was Vice-President, Customer and Asset Management; prior to September 2003, he was Vice-President, Development & Acquisition; and prior to September 2001 he was Director, Commercial Operations, Eastern Canada.

- Prior to July 2007, Dawn Farrell served as Executive Vice-President, Corporate Development, Executive Vice-President, Independent Power Projects and Vice-President, Energy Marketing and IPP Development at TransAlta Corporation. From 2003 to 2006, she served as Executive Vice-President Generation and in June 2006 she was appointed Executive Vice-President Engineering, Aboriginal Relations and Generation at B.C. Hydro.

- Prior to October 2005, Richard Langhammer was President, TransAlta Centralia Generation LLC and TransAlta Centralia Mining LLC, subsidiaries of the Corporation; and prior to December 2003, he was Vice-President, Plant Operations of TransAlta.

- Prior to April, 2007, Kenneth Stickland was Executive Vice-President, Legal.

- Prior to July 2007, Michael Williams was Executive Vice-President, HR & Communications.

- Prior to June 2007, Frank Hawkins was Assistant Treasurer.

- Prior to June 2005, Maryse St.-Laurent was Secretary of TC PipeLines, LP since September 2003 and Recording Secretary since January 2001, and Senior Legal Counsel TransCanada Corporation since June 1997.

As of March 11, 2009, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over an aggregate of 676,330 common shares of TransAlta. This constitutes less than one per cent of TransAlta s outstanding common shares.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Corporation, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10 per cent of the common shares of the Corporation, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving the Corporation within the three most recently completed financial years or to date in 2009 or in any proposed transactions that has materially affected or will materially affect the Corporation.

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2008, there has been no indebtedness, other than routine indebtedness, outstanding to TransAlta from any of TransAlta s directors, nominees for election as directors, executive officers, senior officers or associates of any such directors, nominees or officers.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders

Except as otherwise disclosed herein, no director, executive officer or controlling security holder of TransAlta Corporation is, as at the date of this Annual Information Form, or has been, within the past ten years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No director, executive officer or controlling security holder of TransAlta Corporation has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person s assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of TransAlta Corporation has:

(iv) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or

(v) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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, after taking into account amounts reserved by the Corporation. For further information, please refer to Notes 29 and 31 of the Corporation s audited consolidated financial statements for the year ended December 31, 2008, which financial statements are incorporated by reference herein. See Documents Incorporated by Reference herein.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for TransAlta s common shares is CIBC Mellon Trust Company in Vancouver, Calgary, Winnipeg, Toronto and Montreal. The transfer agent and registrar for the common shares in the United States is Mellon Investor Services LLC at its principal office in New York, New York.

INTERESTS OF EXPERTS

Ernst & Young LLP, Chartered Accountants, 1000, 440 - 2nd Avenue, S.W., Calgary, Alberta, T2P 5E9 are the auditors of the Corporation.

TransAlta s auditors, Ernst & Young LLP, are independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and have complied with the SEC s rules on auditor independence.

ADDITIONAL INFORMATION

Additional information in relation to TransAlta may be found under TransAlta s profile on SEDAR at www.sedar.com.

Additional information including directors and officers remuneration and indebtedness, principal holders of TransAlta s securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransAlta s Management Proxy Circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransAlta Corporation.

Additional financial information is provided in TransAlta s audited consolidated financial statements as at and for the year ended December 31, 2008 and in the Annual MD&A, each of which is incorporated by reference in this Annual Information Form. See Documents Incorporated by Reference herein.

AUDIT AND RISK COMMITTEE

General

The members of TransAlta s Audit and Risk Committee (**ARC**) satisfy the requirements for independence under the provisions of Canadian Securities Regulators, Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange Rules and Rule 10A-3 under the U.S. Securities and Exchange Act of 1934. The ARC s Charter requires that it be comprised of a minimum of three independent directors. It currently has six independent members, William D. Anderson (Chair), Stephen L. Baum, Timothy W. Faithfull, Michael M. Kanovsky, Gordon S. Lackenbauer and Donna S. Kaufman as an ex-officio member. All members of the committee are financially literate pursuant to both Canadian and U.S. securities requirements and each of Mr. William D. Anderson and Mr. Gordon S. Lackenbauer have been determined by the Board to be an *audit committee financial expert* , within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 (**Sarbanes-Oxley Act**).

Mandate of the Audit and Risk Committee

The mandate of the ARC is to assist the Board in its oversight responsibility to the shareholders of the Corporation, the investment community and others relating to the integrity of the Corporation s financial statements, the quality of its financial reporting processes, the systems of internal accounting and financial controls, the risk identification assessments conducted by management and the programs established in response to such risks, the internal audit function, the external auditors qualifications, independence, performance and reports and to provide oversight with respect to legal compliance programs established by management which may have a material effect on the financial statements of the Corporation. The ARC also reviews the Corporation s compliance with the Corporation s code of conduct, financial code of conduct and the Corporation s policy with respect to the hiring of employees of the external auditors.

The ARC s function is oversight. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation. Management and the internal audit group of the Corporation are responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures for compliance with accounting standards and applicable laws and regulations.

While the ARC has the responsibilities and powers set forth herein, it is not the duty of the ARC to plan or conduct audits or to determine that the Corporation s financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors.

Management is responsible for preparing the interim and annual financial statements and financial disclosure of the Corporation and for maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly. The ARC s role is to provide direct, meaningful and effective oversight of the Corporation s financial reporting and counsel to management without assuming responsibility for management s day to day duties.

Audit and Risk Committee Charter

The Charter of the Audit and Risk Committee is attached as Appendix A .

Relevant Education and Experience of Audit and Risk Committee Members

The following is a brief summary of the education or experience of each member of the ARC that is relevant to the performance of their responsibilities as a member of the ARC, including any education or experience that has provided the member with an understanding of the accounting principles used by TransAlta to prepare its annual and interim financial statements.

Name of ARC Member	**Relevant Education and Experience**
W. D. Anderson	Mr. Anderson is a Chartered Accountant. Mr. Anderson has served as Chief Executive Officer of a public company and as Chief Financial Officer of several public companies. In such capacities, Mr. Anderson actively supervised persons engaged in preparing, auditing, analyzing or evaluating financial statements. Mr. Anderson has also served as a principal financial officer and accounting officer and as a director and audit committee member of several public companies.

Stephen L. Baum	Mr. Baum has over 25 years of financial, legal and industry experience gained working as a senior officer, director and Chairman of energy companies. During his tenure as CEO of Sempra Energy, Mr. Baum had financial officers reporting directly to him. Mr. Baum also serves as Chairman of the Audit Committee of Computer Sciences Corporation, a NYSE listed company. Mr. Baum holds a law degree from the University of Virginia.
T. W. Faithfull	Mr. Faithfull holds a Bachelor of Arts degree in Economics and has acquired significant financial experience and exposure to accounting and financial issues as Chief Executive Officer of Shell Canada Limited and in his other capacities during his 36 years with the Royal Dutch/Shell group of companies.
M. M. Kanovsky	Mr. Kanovsky has over 30 years of financial and industry experience gained through working in the investment banking business as well as a director, officer and audit committee member of several public companies and trusts. Mr. Kanovsky is a graduate of the MBA program from the Richard Ivey School of Business at the University of Western Ontario.

Name of ARC Member	Relevant Education and Experience
G. S. Lackenbauer	Mr. Lackenbauer has over 35 years of experience in the investment banking industry. Mr. Lackenbauer has also appeared as an expert financial witness with respect to financial markets, capital structure, cost of capital and fair return on common equity, in over 40 regulatory proceedings. Mr. Lackenbauer also has extensive experience as a director or governor of public companies and not-for-profit organizations. Mr. Lackenbauer holds a Bachelor of Arts in Economics, a MBA degree from the University of Western Ontario and is a Chartered Financial Analyst.
D. S. Kaufman (ex-officio)	Mrs. Kaufman has over 25 years of legal, professional and financial management experience gained in the practice of law, as a director of several public companies and as Chair, President and CEO of Selkirk Communications. Mrs. Kaufman has served on several audit committees. Mrs. Kaufman holds a civil law degree from McGill University and a master of laws from the University of Montreal.

Other Board Committees

In addition to the Audit and Risk Committee, TransAlta has two other standing committees: the Governance and Environment Committee and the Human Resources Committee. Mrs. Kaufman, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as of December 31, 2008 are:

Governance and Environment Committee

Chair: Ambassador Gordon D. Giffin
C. Kent Jespersen
Michael M. Kanovsky
Gordon S. Lackenbauer
Dr. Martha C. Piper
Donna Soble Kaufman (ex-officio)

Human Resources Committee

Chair: Stanley J. Bright
Stephen L. Baum
Timothy W. Faithfull
C. Kent Jespersen
Dr. Martha C. Piper
Luis Vázquez Senties
Donna Soble Kaufman (ex-officio)

The Charters of the Governance and Environment Committee and the Human Resources Committee may be found on TransAlta s website under Corporate Responsibility - Governance at www.transalta.com. Further information about the Board and the Corporation s corporate governance may also be found on our website or in the Corporation s Management Proxy Circular which is filed on Sedar at www.sedar.com.

Fees Paid to Ernst & Young LLP

For the years ended December 31, 2008 and December 31, 2007, Ernst & Young LLP and its affiliates were paid $3,372,142 and $2,838,740 respectively, as detailed below:

Year ended Dec. 31				
Ernst & Young LLP		**2008**		**2007**
Audit fees	$	2,594,183	$	2,624,029
Audit related fees		432,343		168,968
Tax fees		345,616		45,743
Total	**$**	**3,372,142**	**$**	**2,838,740**

No other audit firms provided audit services in 2008 or 2007.

The nature of each category of fees is described below:

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of the Corporation s annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English to French of the Corporation s financial statements and other documents. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923. Total audit fees for 2007 include payments related to 2006 in the amount of $1,476,300.

Audit-Related Fees

The audit-related fees in 2008 were primarily for work performed by Ernst & Young LLP in relation to miscellaneous accounting advice provided to the Corporation.

Tax Fees

Majority of tax fees for 2008 relate to the finalization of tax credit recoveries.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors independence. In May 2002, the ARC adopted a policy that prohibits TransAlta from engaging the auditors for prohibited categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act.

Representatives of Ernst & Young LLP will be in attendance at the Meeting, will have the opportunity to make a statement if they so wish and will be available to respond to questions.

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APPENDIX A

TRANSALTA CORPORATION

(the Corporation)

AUDIT AND RISK COMMITTEE CHARTER

A. Establishment of Committee and Procedures

1. Composition of Committee

The Audit and Risk Committee (the Committee) of the Board of Directors (the Board) of TransAlta Corporation (the Corporation) shall consist of not less than three Directors. All members of the Committee shall be determined by the Board to be independent as required under the provisions of Canadian Securities Regulators Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange rules and Rule 10A-3 of the U.S. Securities and Exchange Act of 1934, as such rules apply to audit committee members. All members of the Committee must be financially literate pursuant to both Canadian and U.S. securities requirements and at least one member must be determined by the Board to be an audit committee financial expert within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 (the Sarbanes Oxley Act). Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the Board of Directors (the Board) at the recommendation of the Committee.

2. Appointment of Committee Members

Members of the Committee shall be appointed from time to time by the Board, on the recommendation of the Governance and Environment Committee, and shall hold office until the next annual meeting of shareholders, or until their successors are earlier appointed, or until they cease to be Directors of the Corporation.

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

4. Committee Chair

The Board shall appoint a Chair for the Committee on the recommendation of the Governance and Environment Committee.

5. Absence of Committee Chair

If the Chair of the Committee is not present at any meeting of the Committee, one of the members of the Committee who is present at the meeting shall be chosen by the Committee to preside at the meeting.

6. Secretary of Committee

The Committee shall appoint a Secretary who need not be a director of the Corporation.

7. Meetings

The Chair of the Committee or any of its members may call a meeting of the Committee. The Committee shall meet at least quarterly and at such other time during each year as it deems appropriate. In addition, the Chair of the Committee or any of its members may call a special meeting of the Committee at any time. Although the Corporation s Chief Executive Officer may attend meetings of the Committee, the Committee shall also meet in separate executive sessions.

8. Quorum

A majority of the members of the Committee present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other, shall constitute a quorum.

9. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing (including by way of written facsimile communication or email) to each member of the Committee at least 48 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive notice of a meeting; and attendance of a member at a meeting constitutes a waiver of notice of the meeting, except where a member attends for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called. Notice of every meeting shall also be provided to the external and internal auditors.

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members, officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board generally not later than the next scheduled meeting of the Board.

12. Review of Charter

The Committee shall evaluate its performance and review and reassess the adequacy of its Charter at least annually or otherwise, as it deems appropriate, and if necessary propose changes to the Governance and Environment Committee and the Board for review and approval.

13. Outside Experts and Advisors

The Committee Chair, on behalf of the Committee, or any of its members is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter.

B. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibility to the shareholders, the investment community and others, relating to the integrity of the Corporation s financial statements, the financial reporting process, the systems of internal accounting and financial controls, the risk identification assessment conducted by management and the programs established by management and the Board in response to such assessment, the internal audit function and the external auditors qualifications, independence, performance and reports to the Corporation. In so doing, it is the Committee s responsibility to maintain an open avenue of communication between the Committee, the external auditors, the internal auditors and management of the Corporation.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management of the Corporation is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and procedures that are in compliance with accounting standards, applicable laws and regulations and that provide reasonable assurances that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly.

While the Committee has the responsibilities and powers set forth herein, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation s financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors. The designation of a member or members as an audit committee financial expert is based on that individual s education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an *audit committee financial expert* does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on a member of the Committee and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation s risks and the development and implementation of policies and procedures to mitigate such risks. The Committee s role is to provide oversight in order to ensure that the Corporation s assets are protected and safeguarded within reasonable business limits.

C. Duties and Responsibilities of the Committee

The Committee shall have the following specific duties and responsibilities:

1. <u>Audit and Financial Matters</u>

The Committee shall:

(a) have direct responsibility for the compensation and oversight of the external auditors including nominating the external auditors to the Board for appointment by the shareholders at the Corporation s general annual meeting. In performing its function, the Committee shall:

(i) review the experience and qualifications of the external auditors senior personnel who are providing audit services to the Corporation and the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S. regulatory registration requirements;

(ii) review and approve annually the external auditors audit plan;

(iii) review and approve the basis and amount of the external auditors fees and ensure the Corporation has provided appropriate funding for payment of compensation to the external auditors;

(iv) review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors independence, including, without limitation, (i) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors report to satisfy itself of the external auditors independence;

(v) resolve disagreements between management and the external auditors regarding financial reporting;

(vi) pre-approve all audit related services including all non-prohibited non-audit services provided by the external auditors; the Chair of the Committee, is authorized to approve all audit related services including non-prohibited non-audit services provided by the external auditors, and shall report all such approvals to the Committee at its next scheduled meeting;

(vii) inform the external auditors and management that the external auditors shall have direct access to the Committee at all times, as well as the Committee to the external auditors; and

(viii) instruct the external auditors that they are ultimately accountable to the Committee as representatives of the shareholders of the Corporation;

(b) review with management and the Corporation s external auditors the Corporation s financial reporting in connection with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation s accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation s accounting principles and underlying estimates;

(c) review with management and the external auditors all financial statements and financial disclosure;

(i) recommend to the Board for approval the Corporation s audited annual financial statements including the notes thereto and, Management s Discussion and Analysis ;

(ii) review any report or opinion to be rendered in connection therewith;

(iii) review with the external auditors the cooperation they received during the course of their review and their access to all records, data and information requested;

(iv) discuss with management and the external auditors all significant transactions which were not a normal part of the Corporation s business;

(v) review the management processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(vi) review with management and the external auditors any changes in accounting principles and their applicability to the business;

(vii) review with management and the external auditors alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditors;

(viii) satisfy itself that there are no unresolved issues between management and the external auditors that could reasonably be expected to materially affect the financial statements;

(d) review with management and the external auditors the Corporation s interim financial statements, including the notes thereto, Management s Discussion and Analysis and earnings release, and approve the release thereof by management to the public;

(e) review and discuss with management and external auditors the use of pro forma or adjusted non-GAAP information and the applicable reconciliation;

(f) on behalf of the Committee, the Chair shall review all public disclosure of material financial information extracted or derived from the Corporation s financial statements;

(g) review with management at least annually the approach and nature of financial information and earnings guidance to be disclosed to analysts and rating agencies;

(h) review and recommend to the Board for approval the Corporation s issuance and redemption of securities, financial commitments and limits, and any material changes underlying any of these commitments;

(i) at least annually, obtain and review the external auditors report with respect to the auditing firm s internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm, any inquiry or investigation by governmental or professional authorities within the preceding five years undertaken respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues;

(j) review quarterly with senior management, the chief legal officer and, as necessary, outside legal advisors, and the Corporation s internal and external auditors, the effectiveness of the Corporation s internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and with the Corporation s policies;

(k) review quarterly with the chief legal officer, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the financial statements of the business;

(l) review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with management s response thereto;

(m) review changes in accounting practices or policies and the financial impact these may have on the Corporation;

(n) discuss with the external auditors their perception of the Corporation s financial and accounting personnel, any recommendations which the external auditors may have, including those contained in the management letter, with respect to improving internal financial controls, choice of accounting principles or management reporting systems, and review all management letters from the external auditors together with management s written responses thereto;

(o) review with management, the external auditors and, as necessary, internal and external legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(p) review annually the Annual Pension Report and financial statements of the Corporation s pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs;

(q) together with the Human Resources Committee of the Board, review annually and as required the overall governance of the Corporation s Pension Plans, approve the broad objectives of the plans and report to the Board annually;

(r) review annually the internal audit department s charter, the scope and plans for the work of the internal audit group the adequacy of the group s resources, the internal auditors access to all functions, records, property and personnel of the Corporation and inform the internal auditors and management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(s) meet separately with management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(t) review the annual audit of expense accounts and perquisites of the Directors, the CEO and his direct reports, including the use of the Corporation s assets, as well as the Corporation s annual sponsorship, donations and political contributions;

(u) review management s processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud and the process put in place for monitoring the risks within targeted areas;

(v) review with the Corporation s senior financial management and the Vice-President Internal Audit the adequacy of the Corporation s systems of internal control and procedures;

(w) review disclosures made to the Committee by the CEO and Chief Financial Officer (the CFO) during their certification process for the relevant periodic reports filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation s disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving management or other employees who have a significant role in the Company s internal controls was reported to the Committee;

(x) ensure that the Corporation s business practices and ethical behaviours are communicated to employees and contractors on an annual basis, to review at least annually the Corporate Code of Conduct and the policies and practices in place to ensure compliance. Inquire of the internal and external auditors as to any instances of deviation from the Corporate Code of Conduct which has come to their attention and the action taken as a result of same;

(y) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding accounting or auditing matters;

(z) review all incidents, complaints or information reported through the Ethics Help Line and/or management;

(aa) review disclosure made to the Committee by the chief executive officer, chief financial officer and/or chief legal officer of a material violation of applicable securities laws, a material breach of a fiduciary duty under applicable laws or a similar material violation by the Corporation or by any officer, director, employee or agent of the Corporation, which has been reported to the Committee, determine whether an investigation is necessary regarding any such report and report to the board;

(bb) discuss with management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation s financial statements or accounting policies;

(cc) report annually to shareholders or on the work of the Committee during the year;

(dd) review and approve the Corporation s hiring policies for employees or former employees of the external auditors and monitor the Corporation s adherence to the policy;

(ee) recommend to the Human Resources Committee the appointment and termination or transfer of the Vice-President, Internal Audit.

2. <u>Risk Management</u>

The Committee provides oversight of management s establishment of an overall risk culture for the Corporation. The Committee shall oversee and approve the processes established and developed by management for the identification of the Corporations principal risks, the evaluation of potential impact and the implementation of appropriate systems to mitigate and manage the risks.

The Committee shall:

(a) review annually with the Board management s assessment of the significant risks to which the Corporation is exposed; discuss with management the Corporation s policies and procedures for identifying and managing the principal risks of its business in order to ensure that management:

(i) has identified appropriate business strategies taking into account the principal risks identified, and

(ii) is maintaining systems and procedures to manage or mitigate those risks, including programs of loss prevention, insurance and risk reduction and disaster response and recovery programs;

(b) receive and review managements quarterly risk assessment update including an update on residual risks, emergent risks and next steps;

(c) review the Corporation s enterprise risk management framework and reporting methodology;

(d) review annually the Corporation s Financial and Commodity Exposure Management Policies and approve changes to such policies; review and authorize strategic hedging program guidelines and risk tolerance; review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(e) review the Corporation s annual insurance program, including the risk retention philosophy and resulting uninsured exposure and corporate liability protection programs for directors and officers including directors and officers insurance coverage;

(f) periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external counsel concerning risk management of the Corporation and review their performance in relation to such roles and responsibilities; and

(g) annually, together with management report to the Board on:

(i) the Corporation s strategies in light of the overall risk profile of the Corporation;

(ii) the nature and magnitude of all significant risks;

(iii) the processes, policies, procedures and controls in place to manage or mitigate the significant risks; and

(iv) the overall effectiveness of risk management processes including highlighting risk management problems and the actions that have been or will be taken to address them.

D. Compliance and Powers of the Committee

(a) The responsibilities of the Committee complies with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition this Charter complies with the applicable US laws, such as the Sarbanes-Oxley Act, and the rules and regulations adopted thereunder, and with the New York Stock Exchanges corporate governance standards, as they exist on the date hereof. This Charter is reviewed from time to time by the Corporate Secretary together with the Chair of the Committee in order to ensure on going compliance with such standards.

(b) The Committee may, at the request of the Board or on its own initiative, investigate such other matters as are considered necessary or appropriate in carrying out its mandate.

APPENDIX B

GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

AEUB means the Alberta Energy and Utilities Board;

Alberta PPA means an Alberta government mandated power purchase arrangement;

availability means the weighted average equivalent availability factor , which is a term used to calculate availability for a pool or fleet of units of varying sizes. It is a measure of time and energy expressed in 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;

capacity means net maximum capacity that a unit can sustain over a period of time;

gigawatt hour or **GWh** means one million kilowatt hours of electrical power;

kilowatt or **kW** means 1,000 watts of electrical power;

kilowatt hour or **kWh** means one hour during which one kilowatt of electrical power has been continuously produced;

megawatt or **MW** means 1,000 kilowatts or one million watts of electrical power;

megawatt hour or **MWh** means 1,000 kilowatt hours;

PPA means a power purchase agreement having an initial term of five years or greater;

watt means the scientific unit of electrical power, being the rate of energy use that gives rise to the production of energy at a rate of one joule per second;

watt hour is a measure of energy production or consumption equal to one watt produced or consumed for one hour; and

WPPI means the Government of Canada s Wind Power Production Incentive available to approved wind generation facilities commissioned between April 1, 2002 and March 31, 2007.

Management 's Discussion and Analysis

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This management's discussion and analysis ("MD&A") should be read in conjunction with the audited 2008 consolidated financial statements. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All dollar amounts in the following discussion including the tables are in millions of Canadian dollars unless otherwise noted. This MD&A is dated March 4, 2009. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including its annual information form, is available on SEDAR at www.sedar.com and on our website at www.transalta.com.

Business Environment

We are a wholesale power generator and marketer with operations in Canada, the United States and Australia. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and have expertise in generation fuels including coal, natural gas, hydro, and renewable energy.

We operate in a variety of markets to generate electricity, find buyers for the power we generate, and arrange for its transmission. Our key markets are Western Canada, the Pacific Northwest, and Eastern Canada. The key characteristics of these markets are described below.

Demand

Demand for electricity is a fundamental driver of prices in all of our markets. Economic growth is the key driver of longer-term changes in the demand for electricity. Demand for electricity in all three of our major markets has been growing at an average rate of one to three per cent per year; however, the current weak economic environment is potentially threatening growth in demand. Alberta has seen the highest rate of growth in demand in recent years, driven by a strong economy. However, development of the oil sands is starting to slowdown as oil sands developers delay and cancel projects. Since a significant portion of Alberta's electricity load is industrial, a slowdown in the oil sands development sector will likely affect overall demand growth. While declines in demand growth over the next few years are not expected to impact us significantly as a result of our highly contracted capability, a more significant decline in the rate of demand growth could occur between 2013 and 2018, when the majority of the delayed and cancelled oil sands projects were scheduled to begin operations. In the Pacific Northwest, demand has grown at a moderate but steady pace but may be threatened due to a recessionary environment in the nearer-term. Demand in Ontario is expected to remain relatively weak, due to reduced manufacturing activity and conservation.

Supply

In all markets in which we operate, the cost of building new generating capacity has increased due to a shortage of component parts and the increased cost of raw materials. We are seeing indications that many North American power companies are postponing the construction of projects or cutting 2009 capital spending. We believe that reserve margins, which are the amount of generating capacity available in excess of the capacity needed to meet normal demand levels, will continue to contract and, as a result, prices are expected to remain fairly strong over the longer-term. In the nearer-term, reserve margins are expected to increase due to weaker economic conditions and new supply coming on stream. Overall, significant changes in investment patterns are expected to increase the volatility in the price of both natural gas and electricity.

In Alberta, the existing thermal fleet is aging, resulting in more outages. As a result of strong economic growth over the past few years, new generation is needed to meet the increased demand, but is limited by transmission connections both within the province and to other markets. In the Pacific Northwest, sufficient generating supply exists in the nearer-term. In Ontario, the anticipated retirement of thermal generation is placing demand on new nuclear, natural gas-fired, and wind generation, although transmission capacity constraints may affect how much new generation can be added to the market.

Transmission

Transmission refers to the bulk delivery system of power and energy between a generating unit and the distribution system that links to wholesale and/or retail customers. Transmission lines themselves serve as the physical path, transporting electricity from the generating unit to the individual distribution systems. Transmission systems are designed with sufficient reserve capacity to allow for "real time" fluctuations in both supply and demand caused by generation plants or loads coming on and off the transmission network.

Transmission capacity refers to the ability of the transmission line, or lines, to transport this bulk supply of electricity, in an amount that balances the demand needs to the generating supply, allows for an amount of power required for system integrity and security, and for reserve capacity to respond to contingency situations on the system. In the past, adequate transmission capacity, tightly correlated to demand growth, served as a buffer to maintaining adequate transmission capacity during periods of new generation builds. Most transmission businesses in North America are still regulated.

In many markets, including Alberta, investment in transmission capacity has not kept pace with growth in the demand for electricity. Lead times in new transmission infrastructure projects are significant and are subject to extensive consultation processes with landowners and ever-changing regulatory requirements. As a result, additions of generating capacity, specifically renewable projects, such as wind, may not have ready access to markets until key transmission upgrades and additions are completed.

Environmental Legislation and Technologies

Environmental issues and related legislation have, and will continue to have, an impact upon our business. In 2007, we began to incur costs as a result of greenhouse gas ("GHG") legislation in Alberta. Legislation in other jurisdictions and at different levels of government is in various stages. Our exposure to increased costs as a result of environmental legislation in Alberta is minimized through change-in-law provisions in our Power Purchase Arrangements ("PPAs").

Both the Canadian and U.S. federal governments are considering cap and trade policies to manage greenhouse gas emissions. However, economic uncertainty fueled by financial market volatility, a developing recession, and Canada's political environment may delay the adoption of such systems. For these reasons, the government in Canada may not implement new environmental legislation until 2010 or later. In the U.S. the Western Climate Initiative ("WCI"), a group of eleven U.S. western states and Canadian provinces unveiled its final version of a cap and trade plan in 2008. Washington State, where our Centralia Thermal plant ("Centralia Thermal") is located, is a member of this group. The regional goal from this initiative is to reduce GHG emissions by 15 per cent below 2005 levels by 2020. Separately, Washington State is also considering its own climate change legislation that could be implemented independently or in coordination with the WCI program.

These initiatives will impact any decision to construct new coal-fired facilities in the region because growth will increase overall emissions and compliance costs. Additional growth would result in a need for alternative energy resources and carbon offsets to be investigated, and those investments could lead to an overall increase in compliance environmental spending. Refer to the Climate Change and Air Emissions section of this MD&A for further details.

While carbon capture and storage ("CCS") technologies are being developed, these technologies are not sufficiently advanced at this time. Consequently, we are expecting environmental compliance costs to increase the cost of generating electricity so long as they are in place and/or the cost of low carbon generation technologies are higher than high carbon generation technologies.

Economic Environment

As a result of the current economic environment, commodity prices, other than electricity, are decreasing. In the short-term, lower commodity prices, specifically natural gas and coal, will not significantly alter our operating costs because those input costs have been contracted. The decrease in commodity prices could result in lower operating costs for us in the future if commodity prices remain low and we can contract at those lower prices. In addition, decreasing commodity prices have begun to lower the price of assets owned by others, which could result in cost-efficient acquisitions to further diversify our portfolio of assets.

A number of financial and industrial counterparties have experienced credit rating downgrades and we expect 2009 will continue to be a challenging year for some of our counterparties as a result of the recent financial crisis and current economic environment. While we had no counterparty losses in 2008, we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties in our trading and hedging activities.

We expect continued strict lending conditions, which could reduce the amount of capital available and/or increase our cost of borrowing. Our strong financial position, available committed lines of credit, and relatively low debt maturity profile allow us to be selective about when we need to go to the market for financing. We see support in the market for successful projects with high returns, so we will continue to evaluate potential projects using the risk management policies that have been developed and take action when appropriate.

Electricity Prices

Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability as well as any contracting strategy. Our Alberta plants operating under PPAs pay penalties or receive payments based upon a rolling 30-day average of spot prices. Longer-term contracts at Centralia Thermal and Sarnia and our shorter-term contracts at Genesee 3 and Wabamun minimize the impact of spot price changes.

Spot electricity prices in our markets are driven by customer demand, generator supply, and the other business environment dynamics discussed above. We monitor these trends in prices and schedule maintenance, where possible, during times of lower prices.

The average spot electricity prices in each of the past three years in our three main markets are shown in the graph above.

For the year ended Dec. 31, 2008, spot prices increased in Alberta and the Pacific Northwest and were essentially flat in Ontario compared to the same period in 2007. Alberta spot prices increased due to higher natural gas prices during the first three quarters of 2008, higher production losses due to higher than normal forced and planned outages, and lost production as a result of transmission system upgrades. The Pacific

Northwest spot prices increased primarily due to higher natural gas prices during the first three quarters of 2008. Ontario spot prices were relatively unchanged, with higher natural gas prices being offset by increased hydro generation.

Fuel Costs

Our generating facilities use either renewable fuel sources such as water, wind, or geothermal or use combustible fuels such as coal and natural gas. The costs of these fuels, including the cost to supply them to our generating facilities, affect our financial results. With the current market conditions, we are generally seeing falling commodity prices, but coal costs are expected to continue to increase due to higher contract and transportation costs. As a result, coal costs at Centralia Thermal are expected to increase 10 to 15 per cent in 2009.

Mining coal in Alberta is subject to cost increases due to increased overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Coal costs for 2009, on a standard cost basis, are expected to increase five per cent from the prior year primarily due to increased capital expenditures.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices.

The previously announced construction of numerous liquefied natural gas ("LNG") terminals throughout North America was expected to significantly impact the natural gas market by allowing for large amounts of natural gas shipments to occur between continents. These terminals would have created an international market of supply and demand, which could have significantly impacted natural gas prices. However, with the recent economic environment, decreasing commodity prices and the supply of natural gas that currently exists in North America, the construction of the majority of the planned LNG terminals has been delayed or cancelled due to higher than anticipated construction costs and insufficient returns. Accordingly, this technology is not expected to have a significant impact on natural gas prices in the near future.

In 2008, the amount of natural gas production in North America from unconventional sources, such as shale gas, has increased. If shale gas production is sustainable and economically viable over the long-term, this increased production from unconventional sources could potentially reduce the price of natural gas over the longer-term.

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

Spark Spreads

Spark spreads measure the potential profit from generating electricity at current market rates.

A spark spread is calculated as the difference between the market price of electricity and its cost of production. The cost of production is comprised of the total cost of fuel and the efficiency, or heat rate, with which the plant converts natural gas to electricity. For most markets, a standardized heat rate is assumed to be 7,000 British Thermal Units (Btu) per Kilowatt hour (KWh).

Using this standardized measure, the average spark spreads in each of the past three years in our three main markets are shown in the adjacent graph.

Spark spreads will also vary between different plants due to their design, the region of the world in which they operate, and the requirements of the customer and/or market the plant serves. The change in the prices of electricity and natural gas and resulting spark spreads in our three major markets affect our Generation and Commercial Operations & Development ("COD") business segments.

For the year ended Dec. 31, 2008, spark spreads increased in Alberta and decreased in the Pacific Northwest and Ontario compared to the same period in 2007. Alberta spark spreads were higher due to increased planned and unplanned outages. Spark spreads in the Pacific Northwest were lower due to increased hydro generation during the second quarter of 2008. In Ontario, spot spark spreads were lower due to increased hydro generation, partially offset by higher natural gas prices.

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

The effect of these prices upon the margins from our generating facilities and our trading activities are described in further detail below.

Strategy

Our strategic position is to deliver shareholder value by maintaining a low-to-moderate risk profile, which is centered around long-term comparable earnings per share ("EPS") growth driven by geographically focusing our operations and expanding our portfolio in the western regions of Canada and the U.S. We are focusing on this geographic area because of market dynamics, such as deregulation, demand growth and potential green energy growth, and our expertise, scale, and access to numerous fuel resources, including coal, wind, geothermal, hydro and natural gas.

Financial Strategy

Our financial strategy is to maintain a strong balance sheet and investment grade credit ratios in our long-cycle, capital intensive, and commodity-sensitive business. A strong balance sheet and investment grade credit ratios improves our competitiveness by providing greater access to capital markets, lowering our cost of capital compared to that of non-investment grade companies and enabling us to contract our assets with customers on more favourable commercial terms. We value financial flexibility, which allows us to selectively access the capital markets when conditions are favourable.

Contracting Cash Flows

In Alberta, demand was almost flat in 2008 compared to the growth experienced in 2007, primarily due to the delayed start-up of several large industrial projects. In 2009, while we do expect some growth in demand in Alberta due to these delayed projects coming online, we expect that demand growth will be softer than initially forecasted. While we will not be immune to softening power prices, the impact is significantly mitigated because across our fleet approximately 90 per cent of 2009 and approximately 85 per cent of 2010 expected capacity is contracted. It is this low-to-moderate risk contracting strategy that helps protect our cash flow and our balance sheet through economic cycles and will ultimately help us through the current downturn in the market.

Growth Strategy

The time frame for delivering on the growth component of our strategy is outlined below.

Short-Term: 2009 2012

During this period, the focus will be on efficiency uprates at our Keephills and Sundance facilities and growing renewable energy capacity, such as wind and geothermal. We will continue our research related to various emission reduction technologies and projects, such as CCS technology and carbon dioxide ("CO_2") offsets. Our focus will be on renewable energy during this time frame until we determine if CCS technology will be economically viable prior to building more coal-fired facilities.

Medium-Term: 2013 2015

During this period, the focus of our strategy will shift to the construction of CCS technologies and investment in the life cycle of our Alberta Thermal plants ("Alberta Thermal") to improve the longer-term efficiency and availability of our facilities. Potential investments in alternative energy sources that have not been traditional growth areas for us, such as hydro, will be investigated along with continued investment in CO_2 offsets.

Longer-Term: Beyond 2016

During this period, our strategy will be to increase overall capacity without increasing our emissions profile. Construction of current growth and emission reduction projects will be completed and in full production, potentially including coal-fired plants with CCS technology. We anticipate having generating assets using alternative energy to be compliant with the expected increase in environmental regulations. This growth could be achieved by partnering with a large hydro operation, potentially obtaining an equity share in alternate energy projects, and/or uprating the capacity of existing facilities.

Capability to Deliver Results

We have numerous core competencies and non-capital resources that will enable us to achieve our corporate objectives, which are discussed below. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of the capital resources available that will assist in enabling us to achieve our objectives.

Portfolio Optimization

We seek to optimize our generating portfolio by owning and managing a mix of assets aimed at providing the highest return for a relatively low level of risk. This optimization requires that we divest or improve returns from our non-core and underperforming assets. Most recently, we sold our Mexico operations and we are currently pursuing an improved long-term contract at Sarnia. In 2009, we will perform upgrades on the gas turbine engines at our Ottawa, Mississauga and Windsor facilities to improve productivity and enhance returns.

Financial Strength

We carefully manage our balance sheet in order to maintain financial strength and flexibility throughout all economic cycles. This discipline is important in the current economic environment. We currently maintain financial ratios that exceed our minimum targets. We continue to maintain $2.2 billion available in committed credit facilities, and as of Dec. 31, 2008, $1.4 billion was available to us. These strong ratios, available credit, and continued positive cash flow from operations provide us with ample financial flexibility and as a result, we can be selective about if and when we go to the capital markets for funding.

Environmental Leadership

We are committed to being industry leaders in environmental stewardship. In the past, we have been involved in various projects directed toward researching and implementing more environmentally friendly technologies at our plants. In April 2008, we announced Project Pioneer that will pilot Alstom Canada's chilled ammonia CCS technology at one of our Alberta Thermal units. This technology has the potential to remove up to 90 per cent of CO_2 emissions. This CCS project will be the largest of its kind and the first project in the world to have an integrated underground storage system. TransCanada PipeLines Limited is participating in the development of Project Pioneer and we are working to secure additional industry partners. Securing industry partners and funding initiatives from the federal and provincial governments are key to accelerating CCS projects across Alberta.

In 2007, we voluntarily installed continuous emissions monitoring systems at Centralia Thermal. In 2008, we reached an agreement with the Department of Ecology in Washington State to voluntarily cut emissions of mercury and visibility-limiting nitrogen oxide. Testing and certification of these new technologies occurred throughout 2008 and will continue into the future. We continue to work with regulators to determine appropriate reduction targets and compliance timelines and to develop future environmental policy. We remain dedicated to being involved in discussions with policy-makers and regulators regarding future environmental legislation and implementation.

Disciplined Capital Allocation

We are committed to optimizing the balance between dividend growth, liquidity requirements, base business investment, growth opportunities, and share buybacks. We have a proven track record of long-term financial stability and are committed to paying dividends to shareholders based on between 60 and 70 per cent of comparable earnings.[1]

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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 63 of this MD&A for a further discussion of comparable earnings, including a reconciliation to net earnings.

We continue to grow our diversified generating fleet in order to increase production and meet future demand requirements, with all growth projects having to exceed corporate hurdles for returns. We currently have 456 megawatts ("MW") of capacity under construction and due to be commissioned in the 2009-2012 period, which is comprised of 225 MW of coal-fired generation, 99 MW of uprates to our thermal coal fleet, and 132 MW of wind power. We are a leading generator of wind power in Canada and these growth projects will increase our total renewable energy capacity.

In addition to our greenfield growth plans, we continue our uprates of existing facilities. These uprates add capability to our existing fleet and provide opportunities for high rates of return.

Lifecycle Planning

Managing the operation and maintenance of our fleet is important to ensure reliable generation and revenues. Ensuring the consistent reliability of our facilities is achieved by understanding current technologies and monitoring new developments in technology for their potential application. Lifecycle planning also involves making decisions as to when changes should be made to our existing facilities and when maintenance should occur on components at those facilities. Our success in providing reliable generation is a result of carefully planned and closely monitored maintenance schedules, as well as efficient response and correction of unplanned outages at our facilities. We expect to see increases in production over time as we continue to optimize our current major and routine maintenance programs.

Operational Excellence

We achieve operational excellence by closely planning and monitoring the routine maintenance requirements of our assets. Over the last five years, our average availability has been 88.1 per cent, which is below our corporate target of 90 to 92 per cent. This decrease in our average availability has been primarily impacted by the declines in availability in 2007 and 2008 due to higher than normal unplanned outages at our plants. A significant portion of these unplanned outages were a result of boiler leaks at our Alberta Thermal facilities.

While Alberta Thermal faced challenges in 2008, we have a solid plan to drive our fleet to 90 to 92 per cent availability. We realize that there is always going to be a trade-off between costs and availability and that there are always going to be operational risks that cannot be entirely eliminated economically. We acknowledge the challenges that were faced in 2008 and have refined our understanding of the business risks and the relationship to maintenance work related to these challenges. Part of our plan to address the boiler leaks at our Alberta Thermal facilities includes a heavy maintenance schedule for 2009, for which the majority of the work is scheduled to take place in the first and second quarters.

In addition, part of our plan to improve availability was implementing the Operations Diagnostic Centre ("ODC"), which came online on Dec. 1, 2008. The ODC is a real-time monitoring centre staffed by highly trained engineers and operators. It uses state-of-the-art technology to enable us to optimize our preventive maintenance work by allowing us to continuously monitor and improve our operation. The ODC is instrumental to improving the efficiency of our generating fleet by enabling us to monitor the entire fleet in one location and to plan and act on a fleet-wide basis, instead of on a somewhat isolated plant-level scale. We believe the investment in the ODC will pay for itself in two years.

We have performed significant planned maintenance work to improve availability and efficiency at Centralia Thermal by modifying the boilers to burn Powder River Basin ("PRB") coal. We completed the Unit 2 boiler modifications, a 500,000-man-hour turnaround, on time and with an excellent safety record. Unit 2 is operating to all performance targets. Unit 1 boiler modifications are scheduled to begin in the spring of 2009.

We will continuously monitor and revise our plans, as necessary, to improve availability and to meet our corporate targets.

Organizational Leadership

Our experienced leadership team is comprised of senior business leaders who bring a broad mix of skills in the electricity sector, finance, law, government, regulation, and corporate governance. The leadership team's experience and expertise, combined with our employees' knowledge and dedication to superior operations, has resulted in a long-term proven track record of financial stability and increasing shareholder value.

Performance Metrics

We have key measures that, in our opinion, are critical to evaluating how we are progressing towards meeting our goals. These measures, which include a mix of operational, risk management, and financial metrics, are discussed below.

Availability

Our plants must be available throughout the year at all times to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, and reduced production as a result of derates. Our goal is to minimize these events through regular assessments of our equipment and a comprehensive review of our maintenance plans. Over the past three years we have achieved an average availability of 87.3 per cent, which is below our long-term target of 90 to 92 per cent. Our availability in 2008 was 85.8 per cent. The graph above shows our availability results for the past three years.

Availability for the year ended Dec. 31, 2008 decreased to 85.8 per cent from 87.2 per cent compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher planned outages as a result of equipment modifications at Centralia Thermal, partially offset by lower derates at Centralia Thermal as in 2007 we conducted test burns of PRB coal.

In 2007, availability decreased to 87.2 per cent from 89.0 per cent in 2006 as a result of derating at Centralia Thermal due to test-burning PRB coal in 2007 and higher unplanned outages in Western Canada. The underlying availability, after adjusting for Centralia Thermal derates, was 90.5 per cent for the year ended Dec. 31, 2007.

Production

Production is a significant driver of revenue in some of our contracts and in our ability to capture market opportunities. Our goal is to optimize production through planned maintenance programs and the use of monitoring programs to minimize unplanned outages and derates. We combine these programs with our monitoring of market prices to optimize our results under both our contracted and merchant facilities. The graph above shows our production results for the past three years.

For the year ended Dec. 31, 2008, production decreased 1,504 gigawatt hours ("GWh") compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, higher planned outages at Centralia Thermal, lower market heat rates at Sarnia, and economic dispatching at Centralia Thermal, partially offset by lower unplanned outages at Centralia Thermal, higher merchant volumes due to the uprate on Unit 4 at our Sundance facility, and lower derates at Centralia Thermal resulting from test burns of PRB coal in 2007.

In 2007, production increased 2,182 GWh compared to the same period in 2006 due to higher production at Centralia Thermal and lower planned outages and increased demand at Sarnia partially offset by higher unplanned outages at Alberta Thermal.

Productivity

Our operations, maintenance, and administration ("OM&A") costs reflect the operating cost of our facilities. These costs can fluctuate due to the timing and nature of planned maintenance activities. The remainder of OM&A costs reflect the cost of day-to-day operations. Our target is to absorb the impact of inflation in our recurring operating costs as much as possible through cost control and targeted productivity initiatives. We measure our ability to maintain productivity on OM&A based on the cost per installed megawatt-hour ("MWh") of capacity.

OM&A costs per installed MWh have increased compared to the same period in 2007 due to cost escalations, higher planned maintenance costs, and increased compensation costs.

Safety

Safety is a top priority with all of our staff, contractors and visitors. Our goal is to improve safety by reducing the rate of injuries by 10 per cent each year and our ultimate target is for no incidents to occur.

	2006	**2007**	**2008**	**Target 09/10**
Injury Frequency Rate ("IFR")	1.96	1.76	**1.28**	Reduce >10% annually

The IFR has consistently decreased over the past three years as a direct result of our continuous efforts to improve safety.

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that requires consistent and stable capital expenditures. Our sustaining capital comprises two components: (1) routine and mine capital, and (2) planned maintenance.

In 2008, we spent $340 million on routine and mine capital and $125 million on planned maintenance. In 2007, we spent $293 million on routine and mine capital and $78 million on planned maintenance. The increase in both routine and mine capital and planned maintenance in 2008 compared to the same period in 2007 was due to higher unplanned outages at Alberta Thermal and Genesee 3, equipment modifications at Centralia Thermal, and higher planned maintenance activities across the fleet.

Our annual target for sustaining capital expenditures is expected to decrease for 2009 to approximately $340 to $390 million, primarily due to lower unplanned outages. We expect to return to normal sustaining capital expenditure levels of $270 to $315 million in 2010 as a result of lower productivity spending, reduced capital spending at CE Generation, LLC ("CE Gen"), and the elimination of capital spending related to Centralia Fuel Blend.

Earnings and Cash Flow From Operating Activities

We focus our base business on delivering strong earnings and cash flow growth. Comparable earnings per share[1] are targeted to increase in the low double-digit range per year with operating cash flows targeted between approximately $800 and $900 million.

	2006	2007	2008	Target 09/10
Earnings per share (comparable basis)	$ 1.16	$ 1.31	**$ 1.46**	>10% annually
Cash flow from operating activities ($ millions)	490	847	**1,038**	800-900

In 2008, earnings per share on a comparable basis increased 11 per cent to $1.46 due to favourable pricing in our core markets, higher merchant volumes due to the uprate on Unit 4 at our Sundance facility, and strong Energy Trading results across all markets, partially offset by higher unplanned outages at Alberta Thermal.

In 2007, earnings per share on a comparable basis increased 13 per cent to $1.31 due to favourable pricing, higher production and lower coal costs at Centralia Thermal, partially offset by higher unplanned outages at Alberta Thermal.

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 63 of this MD&A for a further discussion of comparable earnings, including a reconciliation to net earnings.*

In 2008, cash flow from operating activities increased 23 per cent to $1,038 million due to an increase in cash earnings and favourable changes in working capital including the timing of PPA receipts in 2008.

In 2007, cash flow from operating activities increased 73 per cent to $847 million mainly due to higher cash earnings, and receiving 12 months of contractually scheduled payments in 2007 compared to 11 in 2006.

Investment Ratios

Investment grade ratings support contracting activities and provide better access to capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings. Our objective is to maintain a cash flow to interest ratio of at least four times, a cash flow to debt ratio of at least 25 per cent, and a debt to invested capital ratio of not more than 55 per cent.

Cash flow to interest increased to 7.2 times from 6.6 times in 2007 and 5.5 times in 2006. Cash flow to interest increased in 2008 compared to the same period in 2007 as a result of increased cash from operating activities and lower interest expense.

Cash flow to total debt increased to 31.1 per cent from 30.7 per cent in 2007 and 26.2 per cent in 2006. Cash flow to total debt increased in 2008 compared to the same period in 2007 due to an increase in cash flows from operating activities, which offset the increase in debt balances.

At Dec. 31, 2008, our total debt (including non-recourse debt) to invested capital was 48.1 per cent (45.6 per cent excluding non-recourse debt) compared to the Dec. 31, 2007 ratio of 46.8 per cent and Dec. 31, 2006 ratio of 44.5 per cent. Total debt to invested capital increased in 2008 compared to the same period in 2007 as a result of the issuance of senior notes in the amount of U.S.$500 million.

	2006	**2007**	**2008**	**Target 09/10**
Cash flow to interest (times)	5.5	6.6	**7.2**	Minimum 4
Cash flow to total debt (%)	26.2	30.7	**31.1**	Minimum 25
Debt to invested capital (%)	44.5	46.8	**48.1**	Maximum 55

We seek to maintain financial flexibility by using multiple sources of capital to finance capital allocation plans effectively, while maintaining sufficient liquidity in our investments to support contracting and trading activities. Further, this allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are beneficial to our financial results.

Shareholder Value

Our business model is designed to deliver low-to-moderate risk-adjusted sustainable returns and maintain financial strength and flexibility, which enhances shareholder value in a capital intensive, long-cycle, commodity-based business. Our goal is to achieve consistent comparable return on capital employed ("ROCE")[2] greater than 10 per cent and total shareholder return ("TSR")[1] of 10 per cent or more per year.

The table below shows our historical performance on these measures:

	2006	**2007**	**2008**	**Target 09/10**
Comparable ROCE (%)	9.0	9.7	**9.8**	> 10% annually
TSR (%)	9.2	29.0	**(23.9)**	> 10% annually

Comparable ROCE in 2008 was consistent with the prior year. The decrease in TSR for 2008 was due to a decrease in share price during 2008 as a result of the weakening economic environment. The Standard & Poor's ("S&P")/Toronto Stock Exchange ("TSX") Composite Index decreased 35 per cent during the same period.

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These measures are not defined under Canadian GAAP. We evaluate our performance and the performance of our business segments using a variety of measures. These measures are not necessarily comparable to a similarly titled measure of another company. ROCE is a measure of the efficiency and profitability of capital investments and is calculated by taking earnings before income tax and dividing by total assets less current liabilities. Comparable ROCE measures economic value created from capital investments and is calculated *by taking comparable earnings before tax and dividing by total assets less current liabilities. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods. TSR is the total amount returned to investors over a specific holding period and includes capital gains, capital losses and dividends and is calculated by taking the internal rate of return of all cash flows.*

Results of Operations

The results of operations are presented on a consolidated basis and by business segment. We have two business segments: Generation and Commercial Operations & Development ("COD"). Our segments are supported by a corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.

Some of our accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Critical accounting policies and estimates include: revenue recognition, valuation and useful life of property, plant and equipment ("PP&E"), financial instruments, asset retirement obligations ("ARO"), valuation of goodwill, income taxes, and employee future benefits. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further discussion.

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.

Highlights and Summary of Results

During 2008, we:

- generated net earnings of $235 million compared to $309 million in 2007 and $45 million in 2006,
- generated earnings on a comparable basis[1] of $290 million compared to $264 million for 2007 and $234 million for 2006,
- generated cash flow from operations of $1,038 million compared to $847 million in 2007 and $490 million in 2006, and
- generated free cash flow[2] of $121 million compared to $111 million in 2007 and $230 million in 2006.

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

Year ended Dec. 31	**2008**	2007	2006
Availability (%)	**85.8**	87.2	89.0
Production (GWh)	**48,891**	50,395	48,213
Revenue	**$ 3,110**	$ 2,775	$ 2,677
Gross margin[1]	**$ 1,617**	$ 1,544	$ 1,491
Operating income before mine closure and asset impairment charges[1]	**$ 533**	$ 541	$ 479
Mine closure charges			(192)
Asset impairment charges			(130)
Operating income[1]	**$ 533**	$ 541	$ 157
Net earnings	**$ 235**	$ 309	$ 45
Basic and diluted earnings per common share	**$ 1.18**	$ 1.53	$ 0.22
Comparable earnings per share[1]	**$ 1.46**	$ 1.31	$ 1.16

Cash flow from operating activities	**$ 1,038**	$ 847	$ 490
Free cash flow[2]	**$ 121**	$ 111	$ 230
Cash dividends declared per share	**$ 1.08**	$ 1.00	$ 1.00

As at Dec. 31	**2008**	**2007**	**2006**
Total assets	**$ 7,815**	$ 7,157	$ 7,460
Total long-term financial liabilities	**$ 3,193**	$ 2,858	$ 3,094

1

Earnings on a comparable basis, Gross margin, Operating income before mine closure and asset impairment charges, Operating income, and Comparable earnings per share are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of these items, including a reconciliation to net earnings.

2

Free cash flow is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of this item, including a reconciliation to cash flow from operating activities.

Reported Earnings

In 2008, reported earnings decreased to $235 million, compared to $309 million in 2007 and $45 million in 2006, as shown below:

Net earnings for the year ended Dec. 31, 2006	$	45
Increase in Generation gross margins		83
Mark-to-market movements Generation		(64)
Writedown of coal inventory to lower of cost and market in 2006		44
Decrease in COD margins		(10)
Decrease in operations, maintenance and administration costs		4
Decrease in depreciation expense		4
Centralia coal mine closure charges in 2006		192
Asset impairment charges in 2006		130
Gain on sale of mining equipment		16
Decrease in net interest expense		35
Increase in equity loss		(33)
Decrease in non-controlling interest		4
Increase in income tax expense		(146)
Other		5
Net earnings for the year ended Dec. 31, 2007	$	309
Increase in Generation gross margins		7
Mark-to-market movements Generation		16
Increase in COD gross margins		50
Increase in operations, maintenance, and administration costs		(60)
Increase in depreciation expense		(22)
Gain on sale of mining equipment in 2007		(11)
Decrease in net interest expense		23
Increase in equity loss		(47)
Increase in non-controlling interest		(13)
Increase in income tax expense		(3)
Other		(14)
Net earnings, 2008	**$**	**235**

Generation gross margins[1], net of mark-to-market movements, increased by $7 million for the year ended Dec. 31, 2008 due to favourable pricing, lower derates at Centralia Thermal, and higher merchant volumes as a result of the uprate on Unit 4 at our Sundance facility, partially offset by higher unplanned outages at Alberta Thermal and Genesee 3.

In 2007, generation gross margins, net of mark-to-market movements, increased $83 million as a result of lower planned outages in Western Canada combined with favourable pricing, higher production, and lower fuel costs at Centralia Thermal, partially offset by higher coal costs and higher unplanned outages in Western Canada and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, COD gross margins increased $50 million primarily due to strong results in all markets. As at Dec. 31, 2008, substantially all of these positions had been settled. In 2007, COD gross margins decreased $10 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 and the strengthening of the Canadian dollar relative to the U.S. dollar.

OM&A costs for the year ended Dec. 31, 2008 increased $60 million compared to the same period in 2007 due to cost escalations, higher planned maintenance costs, and increased compensation costs. In 2007, OM&A decreased $4 million compared to the same period in 2006 primarily due to reduced operational spending across the Generation fleet, partially offset by the impact of the economic dispatch at Centralia Thermal in the second quarter of 2006, increased investment in our technological infrastructure, and higher stock compensation costs.

For the year ended Dec. 31, 2008, depreciation expense increased $22 million compared to the same period in 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal. In 2007, depreciation decreased $4 million due to the impairment recorded in 2006 on turbines held in inventory and by lower depreciation as a result of the impairment of the Centralia Gas-fired facility ("Centralia Gas") recorded in 2006.

For the year ended Dec. 31, 2008, net interest expense decreased $23 million compared to the same period in 2007 primarily due to interest received on the settlement of a tax issue and higher capitalized interest, partially offset by lower interest income from cash deposits. In 2007, net interest expense decreased $35 million mainly due to lower long-term debt levels, higher interest income on cash deposits, and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, equity loss increased $47 million compared to the same period in 2007 due to the writedown of our Mexican investment in the first quarter of 2008, partially offset by a tax expense recorded in 2007 as a result of changes in tax law in Mexico. In 2007, equity loss increased $33 million as a result of changes in Mexican tax laws, lower margins, and higher interest expense as a result of refinancing these subsidiaries, partially offset by the recognition of deferred financing fees in 2006.

1 *Gross margin is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of this item, including a reconciliation to net earnings.*

Income tax expense for the year ended Dec. 31, 2008 was comparable to the same period in 2007. In 2007, income taxes increased $146 million compared to the same period in 2006 due to higher pre-tax earnings in 2007, lower benefits from tax rate reductions relating to prior periods, and tax recoveries on the 2006 asset impairment and mine closure charges, partially offset by the recovery from resolution of uncertain tax positions in 2007. Adjusting for these items, the effective tax rate for the year ended Dec. 31, 2008 was 21 per cent compared to 23 per cent in 2007, and 20 per cent in 2006.

Significant Events

Our consolidated financial results include the following significant events:

2008

Kent Hills Wind Farm

On Dec. 31, 2008, our 96 MW Kent Hills Wind Farm, which is located 30 kilometres southwest of Moncton, New Brunswick, began commercial operations. This project was delivered on time and on budget.

Carbon Capture and Storage

On April 3, 2008, we announced an agreement with Alstom Canada to pilot chilled ammonia carbon capture technology at one of our Alberta Thermal units, contingent on acquiring adequate industry and government support.

On April 4, 2008, the Government of Canada announced a $125 million fund to support the development of CCS technologies from the oil sands and from coal-fired electricity plants, and on July 8, 2008, the Alberta government announced its commitment to provide $2 billion in funding for the development of CCS technology. These funding initiatives are key to accelerating CCS projects across Alberta and in particular, our chilled ammonia CCS pilot project with Alstom Canada. We have applied for funding support under both of these programs.

On Dec. 18, 2008, we announced the participation of TransCanada PipeLines Limited in our proposed development of Canada's first fully-integrated carbon capture and storage project. When complete, the plant will be one of the largest CCS facilities in the world and the first to have an integrated underground storage system. The project will pilot Alstom Canada's proprietary chilled ammonia carbon capture technology and will be designed to capture one megatonne of CO_2 at one of our Alberta Thermal units. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site.

Debentures

On July 31, 2008, $100 million of debentures issued by TransAlta Utilities Corporation ("TAU") were redeemed by the holder of the debentures at a price of $98.45 per $100 of notional amount. The debentures had been issued at a fixed interest rate of 5.49 per cent, maturing in 2023, and redeemable at the option of the holder in 2008.

On Oct. 10, 2008, $50 million of debentures issued by TAU were redeemed at a negotiated price. The debentures were originally issued at a fixed interest rate of 5.66 per cent and were to mature in 2033.

As of Dec. 12, 2008, TAU is no longer a reporting issuer.

Contract Negotiations with the International Brotherhood of Electrical Workers ("IBEW")

On July 18, 2008, being unable to reach an agreement with the IBEW representing our Alberta Thermal and Hydro employees, the Government of Alberta approved our application to have the matter referred to a Disputes Inquiry Board. As part of this process, the ability of the IBEW to strike or for us to exercise a lockout was suspended. Contract negotiations continued during this process with the assistance of a government-appointed mediator.

On Sept. 19, 2008, the Disputes Inquiry Board concluded that union members at three of our facilities were required to vote in accordance with the original terms of the Memorandum of Settlement. Discussions were held with the Labour Relations Board and the IBEW to determine a voting process and on Oct. 17, 2008, the IBEW membership at our Alberta Thermal and Hydro facilities reached a settlement and voted to accept our revised offer and ratify the Memorandum of Settlement.

Genesee 3

On Oct. 10, 2008, the Genesee 3 plant, a 450 MW joint venture with EPCOR Utilities Inc. ("EPCOR") (225 MW net ownership interest), experienced an unplanned outage as a result of a turbine blade failure. EPCOR, the plant operator, returned the unit to service on Nov. 18, 2008. As a result of the event, fourth quarter total production was reduced by 210 GWh and gross margin decreased by $15 million.

Mexican Business

On Oct. 8, 2008, we successfully completed the sale of our Mexican business to InterGen Global Ventures B.V. ("InterGen") for gross proceeds of $334 million (U.S.$303.5 million). The sale included the plants at both facilities and all associated commercial arrangements.

The actual net loss as a result of the sale was $62 million, which is calculated below:

Contractual proceeds		$ 334
Less: closing costs		(3)
Net proceeds excluding cash on hand of $1 million		331
Book value of investment		420
Loss before deferred foreign exchange losses		89
Deferred foreign exchange losses on the net assets of the Mexican operations	$ 147	
Deferred gains on financial instruments designated as hedges of the net assets of the Mexican operations	(148)	
Income tax expense on financial instruments	9	
Deferred foreign exchange losses		8
Loss before income taxes		$ 97
Income tax recovery		35
Net loss		**$ 62**

The difference between the $65 million estimated loss on the sale of our Mexican business and the actual net loss of $62 million is due to an increase in earnings of our Mexican assets between the first quarter and the completion of the sale. The gross charge of $97 million is recorded in equity loss.

LS Power and Global Infrastructure

On July 18, 2008, we received a non-binding letter from LS Power Equity Partners, an entity associated with Luminus Management LLC, and Global Infrastructure Partners regarding engaging in a dialogue about a possible acquisition of TransAlta.

On Aug. 6, 2008, the Board of Directors unanimously concluded that the proposal undervalued the company and was not in the best interest of TransAlta and its shareholders. The Board made its determination following a detailed and comprehensive review by a special committee of independent directors and based on advice from financial and legal advisors.

On Oct. 7, 2008, LS Power Equity Partners and Global Infrastructure Partners announced that their proposal set out in the letter on July 18, 2008 had been withdrawn.

Potential Breach of Keephills Ash Lagoon

On July 26, 2008, we detected a crack in the dyke wall at our Keephills ash lagoon. We immediately notified Alberta Environment and the local authorities, and began taking measures to control and mitigate the effects of any potential breach and release of water from the lagoon. A series of dykes were constructed at the Keephills ash lagoon site and the risk associated with the potential breach was successfully mitigated.

Expansion at Summerview

On May 27, 2008, we announced a 66 MW expansion at our Summerview wind farm located in southern Alberta near Pincher Creek. The total capital cost of the project is estimated at $123 million with commercial operations expected to commence by the first quarter of 2010.

Bond Offering

On May 9, 2008, we completed an offering of U.S.$500 million of 6.65 per cent senior notes due in 2018. The net proceeds from the offering were used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

Normal Course Issuer Bid ("NCIB") Program

On May 5, 2008, we announced plans to renew our NCIB program until May 5, 2009. We received the approval to purchase, for cancellation, up to 19.9 million of our common shares representing 10 per cent of our 199 million common shares issued and outstanding as at April 23, 2008. Any purchases undertaken will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2008, we purchased 3,886,400 shares (2007   2,371,800 shares) at an average price of $33.46 per share (2007 $31.59 per share). The shares were purchased for an amount higher than their weighted average book value of $8.95 per share (2007 $8.92 per share) resulting in a reduction of retained earnings of $95 million (2007 $54 million).

Year ended Dec. 31		**2008**		**2007**
Total shares purchased		**3,886,400**		2,371,800
Average purchase price per share	**$**	**33.46**	$	31.59
Total cost	**$**	**130**	$	75
Weighted average book value of shares cancelled		**35**		21
Reduction to retained earnings	**$**	**95**	$	54

Given the current unprecedented level of volatility in the financial markets, we have decided to suspend purchases under our NCIB program at this time in order to maintain maximum financial flexibility. We will re-evaluate financial market conditions throughout 2009 to determine the best use of cash resources going forward.

Uprate at Sundance Facility

On April 21, 2008, we announced a 53 MW efficiency uprate at Unit 5 of our Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009.

Greenhouse Gas Emissions

March 31, 2008 marked the deadline for the first compliance year with Alberta's Specified Gas Emitters Regulations for GHG reductions. Compliance was required for GHGs emitted from the implementation date of July 1, 2007 to Dec. 31, 2007. Affected firms were required to reduce their emissions intensity by 12 per cent annually from an emissions baseline averaged over 2003-2005. For our operations not covered under PPAs, we complied through the delivery to government of purchased emissions offsets, acquired at a competitive cost below the $15 per tonne cap. For Alberta plants having PPAs, we were also responsible for compliance, and the approach was coordinated with PPA Buyers such that a mix of Buyer-supplied offsets and contributions to the Alberta Technology Fund at $15 per tonne were used. The PPAs contain change-in-law provisions that allow us to recover compliance costs from the PPA customers.

Dividend Policy and Dividend Increase

On Feb. 1, 2008, the Board of Directors declared a quarterly dividend of $0.27 per share on common shares. This represented an increase of $0.02 per share to the quarterly dividend which on an annual basis yielded $1.08 per share versus $1.00.

On March 25, 2008, the Board of Directors announced the adoption of a formal dividend policy that targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings.[1]

Blue Trail Wind Power Project

On Feb. 13, 2008, we announced plans to design, build, and operate Blue Trail, a 66 MW wind power project in southern Alberta. The capital cost of the project is estimated at $115 million. Commercial operations are expected to commence in the fourth quarter of 2009.

2007

Tax Rate Change

On Dec. 14, 2007, Bill C-28 received Royal Assent, lowering the federal corporate income tax rate to 15 per cent by 2012. These are further rate reductions from the ones included in Bill C-52, which received Royal Assent on June 22, 2007. A total of $48 million of future income tax benefit was recorded in 2007.

TransAlta Power, L.P.

On Dec. 6, 2007, Stanley Power, an indirect wholly owned subsidiary of Cheung Kong Infrastructure Holdings Limited, announced that it had paid for and acquired all of the limited partnership units of TransAlta Power, L.P. at the price of $8.38 in cash per unit. The transaction was valued at approximately $629 million. This transaction had no material impact on us.

Ottawa Power Purchase Agreement

On Oct. 12, 2007, we signed an agreement amending our original PPA 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. We recorded a $28 million charge in equity losses as a result of this change.

1 *Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this document for a further discussion of this item, including a reconciliation to net earnings.*

NCIB Program

On Sept. 11, 2007, we announced an expansion of our NCIB program under which we could purchase, for cancellation, up to 20.2 million of our 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 continued until May 2, 2008. Purchases were made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2007, we purchased 2,371,800 shares at an average price of $31.59 per share. This purchase price was in excess of the weighted average book value of $8.92 per share, resulting in a reduction to retained earnings of $54 million.

New Brunswick Power Purchase Agreement

On Jan. 19, 2007, we announced a 25-year contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 96 MW of wind power in New Brunswick ("Kent Hills"). We constructed, own and operate the Kent Hills facility for which commercial operations began on December 31, 2008. Total capital costs for the construction of Kent Hills were approximately $170 million. On July 17, 2007, we 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.

Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days from Dec. 31, 2008, the commencement of commercial operations.

Sundance Unit 4 Uprate

During 2007, we completed an uprate on Unit 4 of our Sundance facility that added 53 MW of capacity to this facility.

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 GHG emissions intensity are set on a facility-by-facility basis. The legislation requires a 12 per cent reduction in carbon emission intensity over a baseline for the period 2003 to 2005, 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 $5 million per year until we are able to meet the targets for GHG emissions under the Act.

Dragline Deposit

On June 21, 2007, TAU 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. The total dragline purchase costs are approximately $150 million, with final payments for goods and services due by May 2010. The total payments made under this agreement in 2007 were $18 million.

Keephills 3 Power Plant

On Feb. 26, 2007, we announced that we would be building the 450 MW Keephills 3 coal-fired power plant. The plant is being developed jointly by EPCOR and by us. The capital cost of the project is expected to be approximately $1.7 billion, including associated mine capital, and is anticipated to begin commercial operations in the first quarter of 2011. We own a 50 per cent interest in this unit.

2006

Centralia Coal Mine

On Nov. 27, 2006, we ceased mining activities at our Centralia coal mine as a result of increased costs and unfavourable geological conditions. Inventory extracted up to the date on which we ceased operations was mostly consumed throughout 2007. Coal requirements for the foreseeable future are expected to be sourced from coal imported from the PRB. In 2007, we reduced production at the plant by approximately 2,500 GWh. We completed the Unit 2 boiler modifications at Centralia Thermal in the second quarter of 2008 and Unit 1 boiler modifications are scheduled to begin in the spring of 2009.

We incurred an after-tax charge of $154 million ($0.76 per share) due to asset and inventory writedowns, reclamation liabilities, severance costs and other charges.

As required by GAAP, the restructuring charges appear on their appropriate lines on the Statements of Earnings. These have been summarized in the following table and are described below:

Writedown of coal inventory	$	44
Impact on gross margin		(44)
Mine closure charges		
Mine equipment and infrastructure writedown	$	72
ARO writedown		81
Severance costs and other		39
Total mine closure charges		192
Loss before income taxes	$	(236)
Income tax recovery		82
Net loss impact of event	$	(154)

Writedown of Coal Inventory

Since all coal requirements are now being sourced from an external source, the existing internally produced coal inventory was written down to fair market value, which was the current PRB cost at the time of cessation of mining activities.

Mine Equipment and Infrastructure Writedown

Mine equipment was valued at the lower of current net book value and fair value. The majority of this equipment was anticipated to be sold in 2007. Mining infrastructure, which includes processing facilities, was also written down to its expected fair values.

ARO Writedown

The unamortized cost of future reclamation expenses was recognized immediately.

Severance Costs and Other

This includes salaries payable to employees, estimated benefit obligations, other transition payments as a result of the closure, amounts accrued for estimated contract termination penalties, and writedown of materials and supplies. These costs were paid in 2007 for a total of $24 million with the difference between this amount and the amount above of $39 million due to the strengthening of the Canadian dollar relative to the U.S. dollar.

Further, since Centralia Thermal was not operating at full capacity in 2007 and 2008, certain contracts were no longer backed by physical production at the plant and therefore no longer qualified for hedge accounting. Therefore, under GAAP, we recorded these contracts at fair value and as a result of differences between market prices at that time and those of the contracts, recognized mark-to-market gains on these contracts. As well, we entered into additional contracts to offset some of this exposure and recorded these contracts at fair market value. As a result, on a net basis, based on current forward price estimates at that time, we recorded mark-to-market gains of $35 million. These mark-to-market adjustments, which are not included in the table above, had no cash impact on the 2006 financial statements, although the fair market value will continue to change as market prices change until settlement occurs in future periods.

Centralia Gas Impairment

During our annual impairment review, we concluded that the full book value of our Centralia Gas facility was unlikely to be recovered from future cash flows due to changes in our outlook for the plant's profitability based on market dispatch rates and trading values. As a result, we recorded an $84 million after-tax ($0.42 per share) impairment charge to write the plant down to fair value.

Notice of Preferred Securities Redemption

On Nov. 22, 2006, we announced our intention to redeem all of our 7.75 per cent Preferred Securities, which had an aggregate principal of $175 million. We redeemed these securities on Jan. 2, 2007.

Designation of Eligible Dividends

Under the 2007 legislation enacted by the Department of Finance, Canadian residents are entitled to a higher gross-up and dividend tax credit in 2006 and subsequent years if they receive eligible dividends. The dividends paid by us during 2006, 2007 and 2008 are eligible dividends.

Amendment to Dividend Reinvestment and Share Purchase ("DRASP") Plan

On Oct. 20, 2006, we announced that effective Jan. 1, 2007, we were amending and thereby removing the five per cent discount on the price of shares purchased through the DRASP plan and suspending the issuance of shares from treasury. Instead, shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the TSX on the investment dates. Shares issuable under the DRASP plan have not been registered under any U.S. Federal or State Securities laws and U.S. persons or residents are not eligible to participate in the DRASP plan.

Wabamun Outage

In 2005, an oil spill at Lake Wabamun, Alberta forced us to shut down unit four of our Wabamun coal-fired plant for 39 days. In the fourth quarter of 2006, we settled a portion of our outstanding claim for lost margin and incremental expenses. The terms of the settlement are subject to a confidentiality agreement. The settlement is included in merchant revenues.

Sarnia Power Plant

On Feb. 15, 2006, we signed a five-year contract with the Ontario Power Authority for our Sarnia Regional Cogeneration Power Plant to supply an average of 400 MW of electricity to the Ontario electricity market. The contract was effective Jan. 1, 2006.

Centralia Thermal Reduced Production and Economic Dispatch

Due to heavy rainfall in the Pacific Northwest in the first quarter of 2006, we derated Centralia Thermal and started rebuilding our coal inventory. The impact of derating the plant during this time was partially offset by increasing coal imports and purchasing replacement power. We experienced 875 GWh of lower production during the first quarter of 2006 compared to the same period of 2005.

During the second quarter of 2006, lower market prices allowed us to purchase power at a price lower than our variable cost of production. As a result, Centralia Thermal did not operate for the majority of the second quarter. We experienced 1,936 GWh of lower production during the second quarter compared to the same period of 2005.

In the third quarter of 2006, the 702 MW unit 2 experienced a turbine blade failure. As a result of the event, total production was reduced by 727 GWh. Also, in the third quarter of 2006, higher unplanned outages resulted in 232 GWh of lower production.

In the fourth quarter of 2006, 358 GWh of production at Centralia Thermal was lost as a result of PRB coal test burns at the plant.

For the year ended Dec. 31, 2006, as a result of the above-mentioned events, total production at Centralia was 4,128 GWh lower than in 2005.

Purchase of Wailuku River Hydroelectric L.P.

On Feb. 17, 2006, we purchased a 50 per cent interest in Wailuku River Hydroelectric L.P. through Wailuku Holding Company, LLC ("Wailuku") for cash of U.S.$1 million (CDN$1.2 million). Wailuku had debt of U.S.$19 million (CDN$22 million) at the time of acquisition. Wailuku owns a run-of-river hydro facility in Hawaii with an operating capacity of 10 MW. MidAmerican Energy Holdings Company ("MidAmerican") owns the other 50 per cent interest in Wailuku.

Change in Depreciation Rate

In the first quarter of 2006, we changed the depreciation method of the Windsor-Essex, Mississauga, Ottawa, Meridian, and Fort Saskatchewan plants. Previously, these plants were amortized on a unit-of-production method over the life of the plants. After reviewing the estimated useful life and considering the uncertainty for the plants' operations beyond the terms of the current sales contracts, we determined that it was more reasonable to allocate the remaining net book value of the plants on a straight-line basis over the remaining term of the respective contracts. This increase in depreciation is offset by a reduction in earnings attributable to the non-controlling interests in our consolidated statement of earnings.

Keephills 3 Project

On March 14, 2006, we signed a development agreement with EPCOR to jointly examine the development of the Keephills 3 power project, a proposed 450 MW supercritical coal-fired plant adjacent to our existing Keephills facility.

2006 Federal and Alberta Budgets

On May 24, 2006, the Alberta budget received Royal Assent. As a result, the general corporate income tax rate for Alberta was reduced from 11.5 per cent to 10 per cent effective April 1, 2006. The federal budget received Royal Assent on June 22, 2006. As a result, the general corporate federal tax rate is to be reduced from 21 per cent to 19 per cent by Jan. 1, 2010. The corporate surtax was eliminated for taxation years ended after Dec. 31, 2007 and the federal capital tax has been eliminated effective Jan. 1, 2006. The carry-forward period for non-capital losses and investment tax credits earned after 2005 was extended from 10 to 20 years. As a result of these changes, we reduced income tax expense by $55 million.

Subsequent Events

Sundance Unit 4 Derate

On Feb. 10, 2009, we reported the first quarter financial impact of an extended derate at Unit 4 of our Sundance thermal plant ("Unit 4"). The facility experienced an unplanned outage in December 2008 related to the failure of an induced draft ("ID") fan. At that time, Unit 4, which has a capacity of 406 MW, had been derated to approximately 205 MW. The repair of the ID fan components by the original equipment manufacturer took longer than planned, and therefore, Unit 4 did not return to full service until Feb. 23, 2009. As a result of the extended derate, first quarter production was reduced by 328 GWh and net income declined by $17 million.

We have given notice of a High Impact Low Probability Event to the PPA Buyer and the Balancing Pool, which if successful, will protect us from the financial loss and related penalties. The available penalties that we would expect to recover in net income are anticipated to be $14 million.

Keephills Units 1 and 2 Uprates

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

Dividend Increase

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

Carbon Capture and Storage

On Jan. 27, 2009, the Government of Canada announced in the 2009 federal budget an additional $850 million of funding that has been earmarked to support the development of CCS technologies. The impact of this announcement on us cannot be reasonably determined at this time because specific information regarding the use, distribution timelines, and recipients of the funding have not been clarified by the government.

Discussion of Segmented Results

GENERATION: Owns and operates hydro, wind, geothermal, natural gas- and coal-fired plants and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. At Dec. 31, 2008, Generation had 8,482 MW of gross generating capacity[1] in operation (8,073 MW net ownership interest) and 456 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 18 of this Annual Report.

During 2008, we completed the Kent Hills wind farm in New Brunswick that added 96 MW of generating capacity. Kent Hills operates under a PPA with New Brunswick Power.

We have strategic alliances with EPCOR, ENMAX Corporation ("ENMAX"), and MidAmerican. The EPCOR alliance provided the opportunity for us to acquire a 50 per cent ownership in the 450 MW Genesee 3 project and to build the Keephills 3 project. ENMAX and our Company each own 50 per cent of the partnership in the McBride Lake wind project. MidAmerican owns the other 50 per cent interest in CE Gen and Wailuku.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually 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 impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Canadian and U.S. markets.

The results of the Generation segment are as follows:

	2008		**2007**		**2006**	
Year ended Dec. 31	**Total**	**Per installed MWh[2]**	**Total**	**Per installed MWh[2]**	**Total**	**Per installed MWh[2]**
Revenues	**$ 3,005**	**$ 40.63**	$ 2,720	$ 37.03	$ 2,612	$ 35.64
Fuel and purchased power	**(1,493)**	**(20.18)**	(1,231)	(16.76)	(1,186)	(16.19)
Gross margin	**1,512**	**20.45**	1,489	20.27	1,426	19.45
Operations, maintenance and administration	**487**	**6.58**	447	6.08	458	6.25
Depreciation and amortization	**409**	**5.53**	391	5.33	397	5.42
Taxes, other than income taxes	**19**	**0.26**	20	0.27	21	0.29
Intersegment cost allocation	**30**	**0.41**	27	0.37	28	0.38
Operating expenses	**945**	**12.78**	885	12.05	904	12.34
Operating income before mine closure and asset impairment charges[3]	**567**	**7.67**	604	8.22	522	7.11
Mine closure charges					192	2.62
Asset impairment charges					130	1.77
Operating income	**$ 567**	**$ 7.67**	$ 604	$ 8.22	$ 200	$ 2.72
Installed capacity (GWh)	**73,969**		73,447		73,287	
Production (GWh)	**48,891**		50,395		48,213	
Availability (%)	**85.8**		87.2		89.0	

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1

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

2

We have traditionally presented gross margins and other key elements of the income statement on a per MWh produced. While for specific types of contracts this is an effective measure of profitability between periods, levels of production and associated revenues and costs are not comparable across all plants within the Generation segment. To better gauge overall fleet performance and return on the investment in assets, we have presented overall results on an installed MWh basis, which is a measure of overall fleet capacity.

3

Operating income before mine closure and asset impairment charges is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of these items, including a reconciliation to cash flow from operating activities

Generation Production and Gross Margins

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

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

Year ended Dec. 31, 2007	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh[1]	Gross margin per installed MWh[1]
Western Canada	33,398	45,385	$ 1,302	$ 449	$ 853	$ 28.69	$ 9.90	$ 18.79
Eastern Canada	3,775	7,173	443	303	140	61.75	42.19	19.56
International	13,222	20,889	975	479	496	46.66	22.92	23.74
	50,395	73,447	$ 2,720	$ 1,231	$ 1,489	$ 37.03	$ 16.76	$ 20.27

Year ended Dec. 31, 2006	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh[1]	Gross margin per installed MWh[1]
Western Canada	33,501	45,238	$ 1,291	$ 403	$ 888	$ 28.55	$ 8.90	$ 19.65
Eastern Canada	3,353	7,174	454	300	154	63.23	41.87	21.36
International	11,359	20,875	867	483	384	41.53	23.14	18.39
	48,213	73,287	$ 2,612	$ 1,186	$ 1,426	$ 35.64	$ 16.19	$ 19.45

Western Canada

Our Western Canada assets consist of five coal facilities, three natural gas-fired facilities, 13 hydro facilities, and three wind farms with a total gross generating capacity of 5,224 MW (4,937 MW net ownership interest). We are currently constructing a 450 MW (225 MW net ownership interest) merchant thermal plant at our Keephills facility under a joint venture with EPCOR, which is scheduled to enter commercial production in 2011. We are also currently constructing two wind farms, Summerview 2 and Blue Trail, in southern Alberta. Each farm will have a generating capacity of 66 MW. Blue Trail is scheduled to enter commercial production in 2009 and Summerview 2 is scheduled to enter commercial production in 2010.

Our Sundance, Keephills, and Sheerness plants and hydro facilities operate under PPAs with a gross generating capacity of 4,030 MW (3,835 MW net 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 that is not included in capacity covered by the PPAs is 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 contract a portion of this production to guarantee cash flows.

Due to their close physical proximity, three of our coal-fired plants, 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.

For the year ended Dec. 31, 2008, production decreased 1,034 GWh compared to 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, partially offset by increased merchant production resulting from the Unit 4 uprate at our Sundance facility.

In 2007, production decreased 103 GWh compared to 2006 due to higher unplanned outages at Alberta Thermal, partially offset by increased customer demand at Fort Saskatchewan, increased hydro production, and lower planned outages at Alberta Thermal.

1

We have traditionally presented gross margins and other key elements of the income statement on a per MWh produced. While for specific types of contracts this is an effective measure of profitability between periods, levels of production and associated revenues and costs are not comparable across all plants within the Generation segment. To better gauge overall fleet performance and return on the investment in assets, we have presented overall results on an installed MWh basis, which is a measure of overall fleet capacity.

Gross margin for the year ended Dec. 31, 2008 decreased $64 million ($1.67 per installed MWh) compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher coal costs, partially offset by favourable pricing and higher merchant volumes due to the uprate on Unit 4 of our Sundance facility.

In 2007, gross margin decreased $35 million ($0.86 per installed MWh) compared to 2006 due to higher coal costs, higher unplanned outages at Alberta Thermal, and lower prices, partially offset by lower planned outages at Alberta Thermal and higher excess energy due to the uprate on Unit 4 of our Sundance facility.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities and one wind farm with a total gross generating capacity of 915 MW (793 MW net ownership interest). All four natural gas-fired 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, began commercial operations on Dec. 31, 2008.

For the year ended Dec. 31, 2008, production decreased 485 GWh compared to the same period in 2007, primarily due to higher planned outages and lower market heat rates at Sarnia.

In 2007, production increased 422 GWh compared to 2006 primarily as a result of favourable market conditions, higher customer demand and lower planned maintenance at Sarnia and increased production at Ottawa due to natural gas sales in the first quarter of 2006.

For the year ended Dec. 31, 2008, gross margins were comparable to the same period in 2007. In 2007, gross margins decreased $14 million ($1.80 per installed MWh) compared to 2006 as a result of lower gas sales at Ottawa.

International

Our international assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,043 MW and natural gas- and diesel-fired assets in Australia with a generating capacity of 300 MW. 385 MW of our United States assets are operated by CE Gen, a joint venture owned 50 per cent by us.

Our Centralia Thermal, Centralia Gas, 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 year ended Dec. 31, 2008, production increased 15 GWh compared to the same period in 2007 due to lower unplanned outages and lower derates at Centralia Thermal (in 2007 we conducted test burns of PRB coal), partially offset by higher planned outages as a result of equipment modifications made at Centralia Thermal and economic dispatching at Centralia Thermal in the second quarter.

In 2007, production increased 1,863 GWh compared to 2006 due to lower unplanned outages combined with higher production at Centralia Thermal due to the facility being economically dispatched in the second quarter of 2006, partially offset by lower production at Centralia Gas.

For the year ended Dec. 31, 2008, gross margins increased $77 million ($3.97 per installed MWh) compared to the same period in 2007 primarily due to favourable pricing and mark-to-market movements.

In 2007, gross margins increased $112 million ($5.35 per installed MWh) due to favourable market and contractual pricing and increased production at Centralia Thermal, the writedown of inventory related to the cessation of mining activities of the Centralia coal mine in 2006, and lower coal costs at Centralia Thermal, partially offset by mark-to-market losses in 2007 versus mark-to-market gains in 2006 and the strengthening of the Canadian dollar compared to the U.S. dollar.

Operations, Maintenance, and Administration

For the year ended Dec. 31, 2008, OM&A expenses increased $40 million compared to the same period in 2007 due to cost escalations and higher planned maintenance costs.

In 2007, OM&A expense decreased by $11 million primarily due to lower operational spending and planned maintenance expenditures, partially offset by savings realized from the economic dispatch at Centralia Thermal in the second quarter of 2006.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed, excluding CE Gen:

Year ended Dec. 31	**2008**	2007	2006
Capitalized	**$ 125**	$ 78	$ 84
Expensed	**68**	54	56
	$ 193	$ 132	$ 140
GWh lost	**3,478**	2,056	2,325

Production lost as a result of planned maintenance in the year ended Dec. 31, 2008 increased by 1,422 GWh primarily due to the Unit 2 boiler modifications at Centralia Thermal. Production lost in 2007 decreased by 269 GWh from 2006 due to reduced planned outages across the fleet.

For the year ended Dec. 31, 2008, total capitalized and expensed maintenance costs increased compared to 2007 due to the Unit 2 boiler modifications at Centralia Thermal, higher planned outages across the fleet and cost escalations. Total capital and expensed maintenance costs decreased in 2007 compared to the same period in 2006 primarily due to lower planned maintenance activity at our gas-fired facilities.

Depreciation Expense

For the year ended Dec. 31, 2008, depreciation expense increased $18 million compared to the same period in 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal.

In 2007, depreciation expense decreased $6 million compared to 2006 due to the impairment recorded in 2006 on turbines held in inventory, lower depreciation at Centralia Gas, and the strengthening of the Canadian dollar versus the U.S. dollar, partially offset by the recording of ARO accretion at the Centralia coal mine, increased depreciation as a result of capital spending in 2006, and reduced life of certain parts at Centralia Thermal.

For active mines, accretion expense related to ARO is included in cost of sales. However, the Centralia coal mine is currently considered to be inactive and accretion expense is therefore now recorded in depreciation expense. Accretion expense of $9 million and $10 million related to the Centralia coal mine was recorded in depreciation for the years ended Dec. 31, 2008 and 2007, respectively. Accretion expense of $9 million was recorded in cost of sales for the year ended Dec. 31, 2006.

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

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

Our 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 it is transacted. Results will therefore vary regionally or by strategy from one reported period to the next.

A portion of OM&A costs incurred within COD is 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 intersegment allocation is represented as a cost recovery in COD and an operating expense within Generation.

The results of the COD segment, with all trading results presented net, are as follows:

Year ended Dec. 31	**2008**	2007	2006
Gross margin	**$ 105**	$ 55	$ 65
Operations, maintenance and administration	**53**	34	37
Depreciation and amortization	**3**	1	1
Intersegment cost allocation	**(30)**	(27)	(28)
Operating expenses	**26**	8	10
Operating income	**$ 79**	$ 47	$ 55

For the year ended Dec. 31, 2008, gross margins increased $50 million compared to the same period in 2007 due to increased margins across all markets. As at Dec. 31, 2008, substantially all of these positions had been settled.

For the year ended Dec. 31, 2007, gross margins decreased $10 million compared to the same period in 2006 due to decreased natural gas and eastern region trading margins as a result of natural gas market volatility and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, OM&A costs increased $19 million compared to the same period in 2007, from additional trading compensation as a result of increased gross margins.

OM&A costs for 2007 decreased $3 million due to lower incentive costs as a result of decreased margins as well as lower project consulting expenses.

The inter-segment cost allocations increased slightly in 2008 due to an increase in the work performed on behalf of the Generation segment. The inter-segment cost allocations in 2007 and 2006 were comparable.

Net Interest Expense

Year ended Dec. 31	**2008**	2007	2006
Interest on long-term debt	**$ 147**	$ 145	$ 154
Interest on short-term debt	**30**	26	13
Interest income from tax settlement	**(30)**		
Interest on preferred securities			14
Interest income	**(16)**	(32)	(13)
Capitalized interest	**(21)**	(6)	
Net interest expense	**$ 110**	$ 133	$ 168

$30 million of reported interest income relates to refund interest received or due from taxation authorities for the settlement of outstanding tax issues related to prior periods.

For the year ended Dec. 31, 2008, net interest expense decreased $23 million compared to the same period in 2007 primarily due to interest income received on the settlement of the tax issue discussed above, and higher capitalized interest, partially offset by lower interest income from cash deposits.

In 2007, net interest expense decreased $35 million compared to 2006 due to lower long-term debt balances, the strengthening of the Canadian dollar relative to the U.S. dollar, the redemption of preferred securities, higher interest on cash deposits and interest capitalized related to assets under construction, partially offset by higher short-term debt balances.

Gain on Sale of Assets

As a result of the decision to cease mining activities at the Centralia coal mine in 2006, all associated mining and reclamation equipment was classified as being held for sale. All equipment was recorded at the lower of net book value or anticipated realized proceeds. These assets were included in the Generation segment. In 2007, some of this equipment had been retained for reclamation activities and some was transferred to the Highvale mine for use in production of coal inventory. The equipment retained was reclassified to property, plant, and equipment in 2008. The decision to retain equipment for use in reclamation activities at the Centralia coal 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 their disposal.

During 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million. For the year ended Dec. 31, 2007, we sold equipment with a recorded value of $31 million, received proceeds of $47 million, and recorded a pre-tax gain of $16 million.

Non-Controlling Interests

We own 50.01 per cent of TA Cogeneration, L.P. ("TA Cogen"), which owns, operates, or has an interest in five natural gas-fired and one coal-fired generating facility with a total gross generating capacity of 814 MW. A private investor owns the minority interest in TA Cogen. Our CE Gen joint venture investment includes a 75 per cent ownership of Saranac, a 320 MW natural gas-fired cogeneration facility in New York. Since we own a controlling interest in TA Cogen and Saranac, under Canadian GAAP, we consolidate the entire earnings, assets, and liabilities in relation to TA Cogen's ownership of those assets. Non-controlling interests on the income statement and balance sheet relate to the earnings and net assets attributable to TA Cogen and Saranac that are not owned by us. On the statement of cash flow, cash paid to the minority shareholders of TA Cogen and Saranac is shown as 'Distributions to subsidiaries' non-controlling interests' in the financing section.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2008 increased $13 million due to higher earnings at TA Cogen and CE Gen.

In 2007, earnings attributable to non-controlling interests decreased $4 million due to lower margins at Sheerness and Ottawa, partially offset by higher margins at Meridian.

Equity Loss

As required under Accounting Guideline 15, Consolidation of Variable Interest Entities, of the Canadian Institute of Chartered Accountants ("CICA"), our Mexican operations were accounted for as equity subsidiaries. On Oct. 8, 2008, we successfully completed the sale of our Mexican operations to InterGen for a sale price of $334 million. The sale included the plants at both facilities and all associated commercial arrangements. Refer to the Significant Events section for further details.

The table below summarizes key information from these operations.

Year ended Dec. 31		**2008**		**2007**		**2006**
Availability (%)		**97.5**		92.7		90.8
Production (GWh)		**2,646**		3,084		2,918
Equity loss	**$**	**(97)**	$	(50)	$	(17)
Capital expenditures	**$**		$	1	$	10
Operating cash flow	**$**	**2**	$	(3)	$	(7)
Interest expense	**$**	**13**	$	27	$	32

As at Dec. 31	2008	2007
Total assets	**$**	$ 451
Total liabilities	**$**	$ 369

For the year ended Dec. 31, 2008, availability increased due to lower planned and unplanned outages at Chihuahua and lower unplanned outages at Campeche. In 2007, availability increased primarily due to lower planned outages at Campeche and Chihuahua and unplanned outages at Chihuahua.

As a result of the sale of our Mexican business in 2008, total production decreased by 438 GWh compared to 2007. In 2007, production increased 166 GWh due to higher customer demand at Chihuahua and lower planned outages at Campeche and Chihuahua.

For the year ended Dec. 31, 2008, equity loss increased $47 million due to the writedown of our Mexican investment in the first quarter of 2008, partially offset by a tax expense recorded in 2007 as a result of changes in tax law in Mexico.

As described in the Significant Events section of this MD&A, on Oct. 1, 2007, the Mexican government enacted law introducing a flat tax system starting Jan. 1, 2008, and as a result, we recorded a $28 million charge to equity losses and a corresponding reduction in investments reflecting the expected impact of this change in law in 2007.

For the year ended Dec. 31, 2007, equity loss increased $33 million due to the income tax expense described above, lower margins, and increased interest costs as a result of refinancing these subsidiaries in 2006, partially offset by the recognition of deferred financing fees and the loss incurred on unwinding a cross-currency swap in 2006 related to the refinancing.

Income Taxes

Income tax expense under GAAP is based on the earnings of the period, the jurisdiction in which the income is earned, and if there are any differences between how pre-tax income is calculated under GAAP versus income tax law. Income tax rates and amounts differ based upon these factors. When calculating income tax expense, if there is a difference from when an expense or revenue is recognized under either accounting or income tax rules, we make an estimate of when in the future this difference will no longer be in effect and the anticipated income tax rate at that time. These items are deductible or taxable temporary differences. We base these tax rates upon the rates the government expects to be in effect when these temporary differences reverse.

Therefore, when a government announces a change in future income tax rates, it will affect the anticipated income tax asset or liability that will appear in our financial statements. We have seen several large reductions in future tax expense as a result of the Canadian government reducing future tax rates.

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

Year ended Dec. 31	2008	2007	2006
Earnings (loss) before income taxes per statement of earnings	**$ 258**	$ 329	$ (81)
Equity loss	**(97)**	(50)	(17)
Adjustments:			
Coal inventory writedown			44
Mine closure charges			192
Asset impairment charges			130
Turbine impairment			10
Earnings before income taxes, equity loss and other items	**$ 355**	$ 379	$ 312
Income tax expense excluding equity loss and other items	**73**	86	61
Income tax recovery on one-time adjustments	**(35)**		(132)

Income tax recovery recorded on sale of equity investment						
Income tax recovery from settlement of tax positions		**(15)**		(18)		
Change in tax rate related to prior periods				(48)		(55)
Income tax expense (recovery) per financial statements	**$**	**23**	$	20	$	(126)
Effective tax rate (%)[1]		**21**		23		20

In 2008, we recorded a tax recovery of $35 million related to the sale of our Mexican business.

During 2008 and 2007, we settled certain taxation issues with the associated taxation authorities. As a result, we recorded a future income tax recovery of $15 million and $18 million, respectively, related to these items.

As a result of a reduction in Canadian corporate income tax rates expected to apply to future tax liabilities, income tax expense was reduced by $48 million for the year ended Dec. 31, 2007. In 2006, this change in tax rates reduced income tax expense by $55 million.

Adjusting for the items mentioned above, income tax expense decreased for the year ended Dec. 31, 2008 compared to the same period in 2007 due to lower pre-tax income. In 2007, tax expense increased from the same period in 2006 due to an increase in pre-tax income earnings and the effect of the change in the mix of jurisdictions in which pre-tax income is earned.

1 *To present comparable reconciliations, prior years' effective tax rate analyses were reclassified and calculated on earnings before income tax, equity loss and other items.*

Financial Position

The following chart outlines significant changes in the consolidated balance sheets from Dec. 31, 2007 to Dec. 31, 2008:

	Increase/ (Decrease)	**Explanation of change**
Income taxes receivable	12	Tax recovery from current year provision offset by use of tax prepayments
Inventory	21	Higher inventory balances as a result of lower production and an increase in exchange rates
Restricted cash	(242)	Return of funds
Investments	(125)	Disposal of equity investment
Risk management assets (current and long-term)	206	Price movements
Property, plant, and equipment, net	904	Capital additions and the weakening of the Canadian dollar relative to the U.S. dollar, partially offset by depreciation expense
Goodwill	17	Weakening of the Canadian dollar compared to the U.S. dollar
Assets held for sale, net	(29)	Assets previously held for sale have been reclassified to property, plant, and equipment
Other assets	(18)	Amortization and reclassification of certain costs to property, plant, and equipment
Short-term debt	(208)	Net decrease in short-term debt
Accounts payable and accrued liabilities	209	Timing of operational commitments and the weakening of the Canadian dollar compared to the U.S. dollar
Recourse long-term debt (including current portion)	504	Issuance of long-term debt of U.S.$500 million
Non-recourse long-term debt (including current portion)	24	Weakening of the Canadian dollar compared to the U.S. dollar, partially offset by scheduled debt payments
Risk management liabilities (current and long-term)	(59)	Price movements
Asset retirement obligation (including current portion)	21	Increase in estimate and the weakening of the Canadian dollar compared to the U.S. dollar, partially offset by costs settled
Deferred credits and other long-term liabilities	21	Receipt of funding from joint venture partner
Net future income tax liabilities (including current portions)	53	Tax effect on the decrease in net risk management liabilities
Non-controlling interests	(27)	Distributions in excess of earnings from TA Cogen
Shareholders' equity	211	Net earnings and movements in AOCI, partially offset by shares redeemed under the NCIB and dividends declared

Financial Instruments

Financial instruments are used to manage our exposure to interest rates, commodity prices, currency fluctuations, as well as credit and other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives, which are described below. Financial instruments are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, these changes in fair value will not affect earnings until the financial instrument is settled. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as risk management assets and liabilities.

We have two types of financial instruments: (1) those that are used in the COD and Generation segments in relation to Energy Trading activities, commodity hedging activities, and other contracting activities and (2) those used in the hedging of debt, projects, expenditures, and the net investment in self-sustaining foreign subsidiaries. The majority of the Corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or have contracts that extend beyond the time period for which market-based quotes are available, requiring us to use internal valuation techniques or models.

The majority of our financial instruments and physical commodity contracts are recorded under normal purchase/normal sale accounting or qualify for, and are recorded under, hedge accounting rules. As a result, for those contracts for which we have elected hedge accounting, no gains or losses are recorded through the statement of earnings as a result of differences between the contract price and the current forecast of future prices until the period of settlement. We record the changes in value of these contracts through the

Statement of Other Comprehensive Income ("OCI"). When these contracts are settled, the value previously recorded in OCI is reversed and we receive the contracted cash amount for those contracts.

Under hedge accounting rules we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. For commodity contracts, this testing ensures that the amount of electricity we have contracted to supply or natural gas contracted to buy is still likely to be provided. For financial instruments related to debt and projects, this testing ensures that the amount we have contracted to pay for long-term financing and capital projects has remained consistent in terms of timing and amounts. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. Where hedges are *effective*, that is, it is reasonable that we will fulfill that contract without having to purchase commodities in the market, we continue the accounting treatment described above. Where hedges are *ineffective*, that is, we will be required to fulfill that contract with commodities purchased in the market, these hedges, in total or in part, are considered ineffective. The ineffective portion is no longer recorded as a hedge and the changes in fair value are recorded in income and no longer through OCI.

As well, there are certain contracts in our portfolio that at their inception do not qualify for, or we have chosen not to elect, hedge accounting. For these contracts we recognize mark-to-market gains and losses in the statement of earnings resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not affect the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

Our financial instruments are categorized as fair value hedges, cash flow hedges, net investment hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

Fair Value Hedges

Fair value hedges are used to offset the impact of fluctuations in the foreign currency and interest rates on various assets and liabilities. Interest rate swaps are used to hedge exposures in the fair value of long-term debt caused by variations in market interest rates by fixing interest rates. Foreign exchange contracts are used to hedge certain foreign currency denominated assets and liabilities. Based on the fair value of risk management assets and liabilities at Dec. 31, 2008, approximately 5 per cent of our financial instruments are fair value hedges.

All gains or losses related to fair value hedges are recorded on the statement of earnings, which, in turn, are completely offset by the value of the gains or losses on the fair value of the related debt instruments on the foreign currency denominated assets and liabilities. A summary of how fair value hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract[1]				
Reporting date (marked-to-market)				
Settle contract				

1

Option contracts may require an upfront cash investment.

Cash Flow Hedges

Cash flow hedges are categorized as project or commodity hedges and are used to offset foreign exchange and commodity price exposures on long-term projects as a result of market fluctuations. These contracts have a maximum duration of five years. Based on the fair value of risk management assets and liabilities at Dec. 31, 2008, approximately 94 per cent of our financial instruments are cash flow hedges.

Project Hedges

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. When project hedges qualify for, and we have elected to use hedge accounting, the gains or losses related to these contracts in the periods prior to settlement are recorded in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the financial instruments, any gain or loss on the contracts is included in the cost of the related asset and depreciated over the asset's estimated useful life.

A summary of how project hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract				
Reporting date (marked-to-market)[1]				
Roll-over into new contract				
Settle contract				

1

Any ineffective portion is recorded in the statement of earnings.

Commodity Hedges

Physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. When commodity hedges qualify for, and we have elected to use hedge accounting, the fair value of the hedges is recorded in risk management assets or liabilities with changes in value being reported in OCI, up until the date of settlement. The fair value of the majority of our commodity hedges are calculated using adjusted quoted prices from an active market and/or the input is validated by broker quotes. Upon settlement of these financial instruments, the amounts previously recognized in OCI are reclassified to net earnings.

These commodity contracts are designated as all-in-one hedges. However, unlike a typical financial instrument used in a hedging relationship that results in a net settlement with the counterparty, these contracts will not likely result in a net cash outflow despite their fair value currently resulting in a liability on our balance sheet. For contracts settled by physical delivery, we will physically deliver the electricity at the price fixed under the contract, and receive cash payment for that physical delivery. Any related cash flow hedge after-tax losses will be offset by the notional fair value of the contract. If the all-in-one hedge contracts cannot be settled by physical delivery of the underlying commodity they will be settled financially.

A summary of how commodity hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract[1]				
Reporting date (marked-to-market)[2]				
Settle contract				

1 *Option contracts may require an upfront cash investment.*

2 *Any ineffective portion is recorded in the statement of earnings.*

During the year, the change in the position of financial instruments to a net asset position is primarily a result of changes in future prices on contracts in our Generation segment. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding fair valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2007.

In limited circumstances, we may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under GAAP as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, therefore fair value is determined using valuation models or upon internally developed assumptions or inputs. Our Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, or demand profiles. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2008, Level III instruments had a net carrying value of nil.

For both project and commodity cash flow hedges, when we do not elect for hedge accounting, or the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices or exchange rates related to these financial instruments are recorded through the statement of earnings in the period the gain or loss occurs.

Net Investment Hedges

Cross-currency interest rate swaps, foreign currency forward contracts, and foreign currency debts are used to hedge exposure to changes in the carrying values of our net investments in foreign operations having functional currencies 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. Based on the fair value of risk management assets and liabilities at Dec. 31, 2008, approximately one per cent of our financial instruments are net investment hedges.

Since net investment hedges qualify for hedge accounting, gains or losses related to net investment hedges are recorded in OCI until there is a reduction in the net investment of the foreign operation. Net investment hedges are short-term in nature related to the underlying investment, therefore contracts must be routinely renewed. As each of the short-term contracts mature or is settled, cash inflows or outflows result that are recorded in investing activities on the statement of cash flow to reconcile the difference between contracted rates and market rates at the date of settlement. If there is a reduction in the net investment of the foreign operation, the gains or losses previously recorded in OCI are transferred to net earnings in that period.

A summary of how net investment hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract				
Reporting date (marked-to-market)				
Roll-over into new contract				
Settle contract				
Reduction of net investment of foreign operation				

Non-Hedges

We use natural hedges as much as possible, such as U.S. interest rates on our U.S.-denominated long-term debt, to offset any exposures related to changes in foreign exchange rates. Financial instruments not designated as hedges are used to reduce currency risk on the results of our foreign operations due to the fluctuation of exchange rates beyond what is naturally hedged. All gains or losses related to non-hedges are recorded in the statement of earnings as they do not qualify for, nor have they been designated for, hedge accounting. The fair value of risk management assets and liabilities related to non-hedges at Dec. 31, 2008 had a net value of $nil.

A summary of how non-hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract[1]				
Reporting date (marked-to-market)				
Roll-over into new contract				
Settle contract				
Divest contract				

1

Some contracts may require an initial cash investment.

Employee Share Ownership

We employ a variety of stock-based compensation plans to align employee and corporate objectives. On Feb. 1, 2008, one million stock options were granted at an exercise price of $31.97, being the last sale price of board lots of the shares on the TSX the day prior to the day the options were granted for Canadian employees, and U.S.$31.83, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire on Feb.1, 2019. At Dec. 31, 2008, 1.7 million options to purchase our common shares were outstanding, with 0.6 million exercisable at the reporting date. At Dec. 31, 2007, 1.2 million options to purchase our common shares were outstanding, with 0.8 million exercisable at the reporting date. There is no impact on diluted EPS as a result of these options.

On March 2, 2009, we had 1.6 million outstanding employee stock options with a weighted average exercise price of $23.03. For the year ended Dec. 31, 2008, 0.3 million options with a weighted average exercise price of $20.52 were exercised resulting in 0.3 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $27.96.

Under the terms of the Performance Share Ownership Plan ("PSOP"), certain employees receive grants which, after three years, make them eligible to receive a set number of common shares or the equivalent value in cash plus dividends based upon our performance relative to companies comprising the S&P/TSX Composite Index. After three years, once PSOP eligibility has been determined, 50 per cent of the common shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. At Dec. 31, 2008, there were 0.9 million PSOP awards outstanding (2007   1.0 million). There is no impact on diluted EPS as a result of this program.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below executive level for up to 30 per cent of the employee's base salary for the purchase of our common shares from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. At Dec. 31, 2008, 0.8 million shares had been purchased by employees under this program (2007   0.7 million). This program is not available to officers and senior management.

Employee Future Benefits

We have registered pension plans in Canada and the U.S. covering substantially all employees of the corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options. In Canada, there is a supplemental defined benefit plan for Canadian-based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plan ceased for new employees on June 30, 1998. The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2008.

We provide other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2007.

The supplemental pension plan is an obligation of the corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $52 million to secure the obligations under the supplemental plan.

Statements of Cash Flows

Year ended Dec. 31	2008	2007	Explanation of change
Cash and cash equivalents, beginning of period	**$ 51**	$ 66	
Provided by (used in):			
Operating activities	**1,038**	847	Increase in cash earnings of $47 million and favourable changes in working capital of $144 million primarily due to the timing of PPA receipts in 2008.
Investing activities	**(581)**	(410)	Additional capital spending of $407 million, and a decrease in realized gains on financial instruments of $55 million, partially offset by proceeds from the sale of an equity investment of $332 million.
Financing activities	**(467)**	(444)	Increase in repayments of short-term debt of $532 million and long-term debt of $56 million, and a $55 million increase to repurchase common shares under the NCIB program, partially offset by the issuance of $500 million of long-term debt in 2008 and the redemption of preferred shares of $175 million in 2007.
Translation of foreign currency cash	**9**	(8)	
Cash and cash equivalents, end of period	**$ 50**	$ 51	

Year ended Dec. 31	2007	2006	Explanation of change
Cash and cash equivalents, beginning of year	$ 66	$ 79	
Provided by (used in):			
Operating activities	847	490	Increase in cash earnings of $102 million and favourable changes in working capital due to the collection of 2006 PPA revenues in 2007.
Investing activities	(410)	(261)	Additional capital spending of $375 million due to equipment modifications at Centralia Coal, the Sundance Unit 4 uprate, and Keephills 3, combined with a $245 million loan to our equity investment, partially offset by a $390 million return of restricted cash.
Financing activities	(444)	(243)	$75 million used to repurchase common shares under the NCIB program, the redemption of preferred shares of $175 million in 2007, and an increase in cash dividends paid on common shares of $71 million due to the cessation of dividends being reinvested in the DRASP Plan in 2007.
	(8)	1	

Translation of foreign currency cash				
Cash and cash equivalents, end of period	$	51	$	66

Liquidity and Capital Resources

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

Our liquidity needs are met through a variety of sources, including: cash generated from operations, short-term borrowings against our credit facilities, and long-term debt issued under our U.S. shelf registrations and Canadian medium-term 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 total of $2.2 billion of committed credit facilities of which $1.4 billion is not drawn and is available as of Dec. 31, 2008, subject to customary borrowing conditions. At Dec. 31, 2008, credit utilized under these facilities is $0.8 billion, which is comprised of short-term debt of $443 million, less cash on hand of $50 million, and letters of credit of $430 million.

Our ability to generate adequate cash flow from operations in the short-term and the long-term to maintain financial capacity and flexibility and to provide for planned growth remains substantially unchanged since Dec. 31, 2007. In the first quarter of 2008 we received $116 million worth of PPA revenue from 2007 due to the timing of contractually scheduled payments. Consequently, the effect of the timing of these payments is that we have received 13 months of revenue in 2008.

On March 2, 2009, we had approximately 198 million common shares outstanding.

Guarantee Contracts

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 Dec. 31, 2008, we had issued letters of credit totalling $430 million compared to $550 million at Dec. 31, 2007. This decrease in letters of credit is due primarily to lower forward electricity prices in the Pacific Northwest. These letters of credit secure certain amounts included on our balance sheet under "Risk Management Liabilities" and "Asset Retirement Obligations."

Working Capital

For the year ended Dec. 31, 2008, the excess of current liabilities over current assets of $730 million is mainly a result of higher accounts payable and accrued liabilities, combined with a higher current portion of long-term recourse debt, partially offset by an increase in net risk management assets and lower short-term debt balances.

For the year ended Dec. 31, 2007, the excess of current liabilities over current assets of $686 million is mainly due to higher short-term debt balances, and lower accounts receivable balances, partially offset by receiving November 2006 revenues, as contractually scheduled, on Jan. 2, 2007.

Capital Structure

CICA Handbook 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.

Our capital structure consisted of the following components as shown below:

As at Dec. 31	**2008**		**2007**	
Debt, net of cash and cash equivalents	**$ 2,758**	**48%**	$ 2,437	47%
Non-controlling interests	**469**	**8%**	496	9%
Common shareholders' equity	**2,510**	**44%**	2,299	44%
	$ 5,737	**100%**	$ 5,232	100%

Contractual repayments of long-term debt, commitments under operating leases, fixed price purchase contracts, growth project commitments, and commitments under mining agreements are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Long-term debt	Interest on long-term debt[1]	Growth project commitments	Total
2009	$ 9	$ 17	$ 51	$ 244	$ 158	$ 292	$ 771
2010	7	19	47	32	145	74	324
2011	7	19	47	254	133	4	464
2012	7	19	47	397	112		582
2013	8	18	51	396	98		571
2014 and thereafter	37	73	317	1,033	564		2,024
Total	$ 75	$ 165	$ 560	$ 2,356	$ 1,210	$ 370	$ 4,736

1 *Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.*

Off-Balance Sheet Arrangements

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such off-balance sheet arrangements.

Climate Change and Air Emissions

The variety of combustible 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. We place significant importance on environmental compliance to ensure we are able to continuously deliver low cost electricity.

Ongoing and Recently Passed Environmental Legislation

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.

Canada

In Canada, the Conservative Government has indicated its intention to coordinate its climate change policies more closely with those of the U.S., and to seek alignment on a continental cap and trade system. To date there has been no detail as to when this alignment would occur or how Canada's system might be designed. Furthermore, there has been no announcement as to the fate of the prior intensity-based program proposed by the previous Conservative Government. Consequently, at this time it is not possible to fully assess how these broad directional objectives will affect us.

On Jan. 24, 2008, the Government of Alberta announced its long-term intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing CCS technologies, developing conservation and energy efficiency programs, and increasing investment in clean energy technologies. We continue to assess the impact of this proposal upon our operations and our own investment in environmental technologies and programs.

Alberta continues to maintain its GHG regulatory regime that was implemented on July 1, 2007, under the *Climate Change and Emissions Management Amendment Act.* Under the legislation, baselines and targets for GHG intensity are set on a facility-by-facility basis. The legislation and subsequent regulations require a 12 per cent reduction in GHG emission intensity from a baseline set as the average level of emissions during 2003 to 2005. New facilities are exempt for three years and subsequently are subject to a slowly increasing reduction requirement. Emissions over the baseline must be mitigated either through contributions to an Alberta Technology Fund at $15 per tonne, or through the purchase and retirement of Alberta-based offsets from non-regulated sectors. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover these compliance costs from the PPA customers. For 2008, after flow-through, our annual net greenhouse gas compliance costs will be less than $2 million (2007 less than $1 million). We have measures in place to meet the anticipated reduction targets for 2008 and 2009, and continue to examine compliance options, including additions to our offsets portfolio to minimize our compliance risk beyond that period.

In August 2007, the Government of Ontario announced its climate change action plan which included a target to reduce GHG emissions by six per cent below 1990 levels by 2014. Subsequently, the Government of Ontario has indicated its intention to implement a cap and trade system for greenhouse gases by 2010, although no additional legislation or details have been developed at this time.

United States

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect on July 22, 2007. Our 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.

Washington State is developing the conceptual design for a cap and trade mechanism to manage greenhouse gases. On Dec. 12, 2008, the State introduced draft legislation to enable a cap and trade system to be implemented by 2012. Specific details of caps and allocations will be developed in 2009. In parallel, Washington State is engaged with other western states and some Canadian provinces in the WCI to examine a regional cap and trade system for CO_2 emissions. On Sept. 23, 2008, the WCI released its design for a regional greenhouse gas cap and trade system, which will be influential in individual state regulation development. At this point there are no indications as to how these initiatives will impact our fossil-fired assets in Washington.

Federally in the U.S., President Obama has indicated his intentions to push forward legislation on GHGs in 2009. While some form of cap and trade legislation is anticipated, it is still premature to assess when the legislation might become law and what the specific impacts would be on our U.S. assets.

Legal Implications

There are currently no ongoing legal actions as a result of environmental legislation.

TransAlta Activities

We believe that climate change has the potential to impact the business environment in which we operate. We continuously act to reduce the environmental impact of our operating activities because severe changes in weather, such as drought and temperature changes, could hinder our operating abilities and ultimately, our profits. Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We believe that increased scrutiny will be placed on environmental emissions and compliance, and we therefore have a proactive approach to minimizing risks to our results.

Our environment management programs encompass several elements:

- construction of renewable power sources,
- operational excellence that has reduced outages and environmental impact,
- active participation in policy discussions,
- clean technology including CCS development,
- development of cleaner generation technologies, and
- continued investment in an offsets portfolio.

Renewable Power

Our investment in renewable power sources continues through the building of renewable power resources such as the Kent Hills, Summerview 2 and Blue Trail wind farms.

Policy Discussions

We are active in policy discussions at a variety of levels of government. These stakeholder negotiations have allowed us to engage in proactive discussions with governments to meet environmental requirements over the longer-term.

As one of the founders, and active members, of the Clean Coal Power Coalition, we aim to secure a future for coal-fired electricity generation, within the context of Canada's multi-fuelled electricity industry, by proactively addressing environmental issues in cooperation with government and our stakeholders. We are also part of a group of companies participating in the Integrated CO_2 Network to work with the Albertan and Canadian governments to develop carbon capture and storage systems for Canada.

CCS Development

On July 8, 2008, the Alberta government announced its plan to provide funding of $2 billion for new CCS projects operational before 2015. On Nov. 12, 2008, we announced that the CCS pilot project was accepted to the short list of projects for funding under this program. On Dec. 18, 2008, we announced the participation of TransCanada PipeLines Limited in our proposed development of Canada's first fully integrated carbon capture and storage project. When complete, the plant will be one of the largest CCS facilities in the world and the first to have an integrated underground storage system. The project will pilot Alstom Canada's proprietary chilled ammonia carbon capture technology and will be designed to capture one megatonne of CO_2 at one of our Alberta Thermal units. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site. A full project proposal is now being prepared and will be submitted to the Alberta government by March 31, 2009. The government will select the successful projects for funding by June 30, 2009.

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We are continuing with detailed technology testing and engineering design in preparation for installing mercury control equipment at our Alberta Thermal operations by 2010 in order to meet the province's 70 per cent reduction objectives and are on track to meet that deadline. We submitted our mercury control plan in March 2007. In prior years we have invested in other capture technologies such as those for sulfur dioxide.

The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us the opportunity to recover compliance costs from the PPA customers.

Offsets Portfolio

We continue to pursue emission offset opportunities that also allow us to meet emission targets at a competitive cost. We ensure that any investments in offsets will meet certification criteria in the market in which they are to be used.

Future Growth

In 2008, we estimate that 38.5 million tonnes of GHGs with an intensity of 0.893 tonnes/MWh (2007 39.3 million tonnes of GHGs with an intensity of 0.880 tonnes/MWh) were emitted as a result of normal operating activities.[1] Total GHG emissions decreased in 2008 due to lower availability and production. Our planned growth over the next four years, as discussed in the Capability to Deliver Results section of this MD&A, will result in 456 MW of capacity being added to our generation fleet. This growth and the related increase in emissions will be partially offset by the decommissioning of Unit 4 at our Wabamun plant. We estimate that approximately 0.3 million tonnes of additional GHGs will be emitted each year as a result of these projects being completed. The various activities discussed above, including our investment in renewable power and CCS technology, are designed to minimize the environmental and financial impacts of the expected increase in emissions.

Our Board of Directors continues to monitor the results of our reduction efforts and future reduction plans to ensure we are compliant with existing environmental regulations and to ensure that we will be compliant with future legislation.

1 *2008 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO2, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO2.*

2009 Outlook

Business Environment

Power Prices

For 2009, lower natural gas prices and slowing year-over-year demand growth due to the current weak economic environment could result in reduced power prices compared to prior periods in some of our markets. The potential change in power prices as a result of the current economic environment is not expected to materially affect our results as we currently have approximately 90 percent of our expected 2009 capability contracted.

In 2009, approximately 16 per cent of production at our natural gas-fired facilities and seven per cent of production at our coal-fired facilities is exposed 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.

Environmental Legislation

For 2009, we anticipate increasing regulatory clarity on future GHG requirements as both the Canadian and U.S. governments develop their programs. Given recent announcements, we now expect environmental regulations to move in the direction of a cap and trade system.

In Alberta, current regulations on greenhouse gases and air pollutants are clear, but it is uncertain how federal regulations will affect Alberta firms once federal regulations are implemented. We expect discussions to take place in 2009 between the Federal Government and the provinces about what rules are to be applied and their administration. In Washington State, we expect to see details of the State's cap and trade legislation by the end of 2009.

We are active participants in consultations leading up to the formation of these legislative and regulatory mechanisms.

Economic Environment

As a result of the current economic environment, commodity prices are decreasing, which could result in lower input costs for us in the future. Although we have contracted the price of the majority of our inputs in the short-term, in the long-term we may see the benefit of lower operating costs.

A number of financial and industrial counterparties have experienced credit rating downgrades and we expect 2009 will continue to be a challenging year for some of our counterparties as a result of the recent financial crisis and current economic environment. While we had no counterparty losses in 2008, we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties in our trading and hedging activities.

We expect continued strict lending conditions, which could reduce the amount of capital available. Our strong financial position, available committed lines of credit, and relatively low debt maturity profile allow us to be selective about when we need to go to the market for financing. We see support in the market for successful projects with high returns, so we will continue to evaluate potential projects using the risk management policies that have been developed and take action when appropriate.

We do not expect our results from operations in 2009 to be significantly impacted by the current economic environment because production amounts and prices are mainly contracted through our PPAs.

Operations

Production, Availability, and Capacity

Generating capacity is expected to increase late in 2009 due to the completion of Blue Trail and the uprate at Sundance Unit 5. Production and availability are expected to increase in the second half of 2009 primarily due to lower unplanned outages at Alberta Thermal. Overall production for 2009 is expected to increase compared to 2008 primarily due to lower unplanned outages at Alberta Thermal and higher expected production at Centralia Thermal.

Fuel Costs

Coal mining in Alberta is subject to cost increases related to mining such as increased overburden removal, inflation, and increases in commodity prices such as diesel. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Coal costs for 2009, on a standard cost basis, are expected to increase five per cent from the prior year primarily due to increased capital expenditures.

Fuel at Centralia Thermal is purchased from external suppliers in the PRB and delivered by rail. The delivered cost of fuel is expected to increase between 10 and 15 percent from the prior year due to rail and transportation contract escalations.

Our natural gas-fired facilities have minimal exposure to market fluctuations in energy commodity prices. Exposure to natural gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term natural gas purchase contracts. Merchant natural gas facilities are exposed to the changes in spark spreads, as discussed in the Business Environment section, as the majority of the natural gas is purchased on a spot basis. The input costs that are purchased on a spot basis are expected to decrease in 2009 due to lower prices resulting from the current economic environment.

In addition, the decreasing commodity prices have the potential to lower the price of existing assets available for sale, which could result in more cost-efficient acquisitions to further diversify our portfolio of assets.

Operations, Maintenance, and Administration Costs

OM&A costs per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per installed MWh in 2009 are expected to increase due to higher planned maintenance activities in Alberta and cost escalations, partially offset by productivity initiatives. The increase in planned maintenance activities is expected to improve our availability at Alberta Thermal.

Energy Trading

Earnings from our COD segment are affected by prices in the market, the positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2009 objective is for Energy Trading to contribute between $65 million and $85 million in gross margin.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign currency expenses, including interest charges, which are also used to mostly offset foreign currency revenues.

Net Interest Expense

Net interest expense for 2009 is expected to be higher mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar to the U.S. dollar will affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, there may be the need for additional liquidity. To mitigate this liquidity risk, we maintain and monitor $2.2 billion of committed credit facilities and monitor exposures to determine any expected liquidity requirements. We have taken steps in order to maintain maximum financial flexibility, such as suspending purchases under our NCIB program, until we gain a better understanding of where markets may settle.

Accounting Estimates

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

Capital Expenditures

Projects and Growth

Our major projects are comprised of spending on sustaining our current operations and for growth activities. Six significant growth capital projects are currently in progress: Keephills 3, Blue Trail, Sundance Unit 5 uprate, Summerview 2, and Keephills Units 1 and 2 uprates. A summary of each of these projects is outlined below:

Project	Total spend (millions)	Expected 2009 spend (millions)	Expected completion date	Details
Keephills 3	$ 888	$ 235 255	Q1 2011	A 450 MW (225 MW net ownership interest) coal-fired supercritical plant

							and associated mine capital in a partnership with EPCOR
Blue Trail		115		85	90	Q4 2009	A 66 MW wind farm in southern Alberta
Sundance Unit 5 uprate		75		50	60	Q4 2009	A 53 MW efficiency uprate at our Sundance facility
Summerview 2		123		80	90	Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate		34		5	10	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate		34		5	10	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Total growth	$	1,269	$	460	515		

Our estimate of total costs for Keephills 3 has increased by $73 million compared to previous estimates due to higher material and labour costs. We continue to monitor these costs and look for opportunities to reduce these increases.

Sustaining Expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2009, our estimate for total sustaining capital expenditures is between $340 million and $390 million net of any contributions received, allocated among:

$155 $180 million for routine capital,

$35 $45 million for mining equipment and land purchases,

$20 $25 million for Centralia modifications, and

$130 $140 million on planned maintenance, as outlined in the following table:

		Coal		Gas and Hydro		Total
Capitalized	$	85 90	$	45 50	$	130 140
Expensed		85 90		0 5		85 95
	$	170 180	$	45 55	$	215 235
GWh lost		2,600 2,700		250 275		2,850 2,975

In 2009, we expect to lose approximately 2,850 to 2,975 GWh of production due to planned maintenance.

Included in our estimate for routine capital expenditures is productivity capital, which is used for various initiatives that are designed to improve the productivity of existing facilities. The overall increase in sustaining capital expenditures for 2009 is related to a productivity initiative at our Ontario cogeneration plants. In 2009, we will perform upgrades on the natural gas turbine engines at our Ottawa, Mississauga, and Windsor facilities. This new productivity investment, along with other investments, brings our total productivity spend in 2009 to $50 million. We expect these investments in productivity to provide returns in excess of 20 per cent.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity. The funds required for committed growth and sustaining projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flow and amount of credit available at Dec. 31, 2008.

Related Party Transactions

On January 1, 2009, TAU and TransAlta Energy Corporation ("TEC") transferred certain generation and transmission assets to a newly formed internal partnership, TransAlta Generation Partnership ("TAGP"), before amalgamating with TransAlta Corporation.

On Dec. 16, 2006, TAU, a wholly owned subsidiary, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership with EPCOR Power Development Corporation. TAU will supply coal until the earlier of the permanent closure of the Keephills 3 facility or from early termination of the agreement by TAU and the partners of the joint venture. As at Dec. 31, 2008, TAU had received $27 million from Keephills 3 Limited Partnership, a wholly owned subsidiary, for the right to coal. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011. Payments received prior to that date for the right to coal are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

In August 2006, we entered into an agreement with CE Gen, a corporation jointly controlled by us and MidAmerican, a subsidiary of Berkshire Hathaway, whereby we buy available power from certain CE Gen subsidiaries at a fixed price. As this available power is from plants that are already contracted, the value of this agreement is immaterial. 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, one of our subsidiaries, TA Cogen, entered into various transportation swap transactions with 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 the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the transaction was the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. We entered into an offsetting contract and therefore we have no risk other than counterparty risk.

Risk Management

Our business activities expose us to a wide variety of risks. Our goal in managing these risks is to protect the Corporation from an unacceptable level of earnings or financial exposure while still enabling business processes and opportunities. We use a multi-level risk management oversight structure to manage these objectives by ensuring that the risks arising from our business activities, the markets in which we operate, and the political environments in which we operate is mitigated. As evidence of our dedication to excellent risk management and corporate governance, we were awarded the Private Sector Conference Board of Canada/Spencer Stuart 2009 National Award in Governance on Feb. 10, 2009.

The responsibilities of the various stakeholders of our risk management oversight structure are described below:

The Board of Directors provides stewardship of the Corporation, establishes policies and procedures, defines risk tolerance as established under the TSX corporate governance guidelines, and receives the annual comprehensive Enterprise Risk Management

("ERM)" review. The ERM reviews consist of a holistic view of the company's inherent risks, how we mitigate these risks, and residual risks. It defines these risks, discusses who is responsible to manage the risks, how the risks are inter-related with each other, and what the risk metrics are. The Board of Directors examines the ERM review in order to fulfill its requirement to understand the key risks of the company and directs management to address any risk levels with which it is uncomfortable.

Audit and Risk ("A&R") Committee, established by the Board of Directors, provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of our financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications, terms and conditions of appointment, including remuneration, independence, performance and reports; and the legal and risk compliance programs as established by management and the Board of Directors. The A&R Committee approves our Commodity Risk and Financial Exposure Management policies and reviews quarterly ERM reporting.

Exposure Management Committee ("EMC") is chaired by our Executive VP and Chief Financial Officer and is comprised of the Executive Vice-President of Commercial Operations and Development, Executive Vice-President of Generation Operations, Vice-President of Commercial Operations, Managing Director of Trading, Vice-President and Treasurer, Vice-President of Financial Operations, Vice-President and Comptroller, and the Director of Risk Management. The EMC is responsible for reviewing, monitoring, and reporting on our compliance with approved financial and commodity risk exposure management policies.

Corporate Treasury is responsible for the management, oversight, and reporting of financial risks, including: interest rate, foreign exchange, credit, liquidity, and insurable risks. The objectives are to maintain a low cost of capital by mitigating earnings volatility, maintain access to capital markets, and avoid losses. Our risk management policy requires that there be sufficient resources and training available to fulfill these objectives, including maintaining segregation of duties, all in accordance with risk management best practices.

Risk Management is staffed by experienced risk professionals who are responsible for enterprise risk reporting to the Board and A&R Committee, analyzing commercial and environmental risk exposures in our assets and trading operations, as well as ensuring our daily market price exposure is kept within VaR limits. The Risk Management group uses a variety of processes and models to perform this analysis.

Our risk management practices address key risk factors. These are described in greater detail as follows.

Risk Controls

Our management of these risks is also described in the respective sections. Our risk controls have several key components:

Enterprise Tone

Our corporate values are clearly articulated throughout the organization. Employees sign agreements outlining their commitment to our corporate code of conduct.

Policies

We maintain a set of enterprise-wide policies that have been established to address key risks. These policies establish delegated authorities and limits for business transactions, as well as allow for an exceptional approval process. We perform periodic reviews and audits to ensure compliance with these policies.

Reporting

We regularly report risk exposures to key decision makers including the Board of Directors, senior management, and the EMC. This reporting includes analysis of risks being assumed, existing risk exposures, and recommendations for any suggested course of action. This frequent reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a system in place where employees may report any potential ethical concerns. These concerns are directed to the Vice-President Internal Audit who engages Corporate Security, Legal and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the Audit and Risk Committee.

Value at Risk and Trading Positions

VaR is the most commonly used metric employed to track the risk of trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum loss over a specified period of time.

VaR is the primary measure used to manage COD's exposure to market risk resulting from trading activities. VaR is monitored on a daily basis, and is used to determine the potential change in the value of our marketing portfolio over a three-day period within a 95 per cent confidence level resulting from normal market fluctuations. Stress tests are performed weekly on both earnings and VaR to measure the potential effects of various market events that could impact financial results, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. The 3-day average VaR for the year ending Dec. 31, 2008 was $6 million compared to $4 million for the same period in 2007.

We estimate VaR using the historical variance/covariance approach. Currently, there is no uniform energy industry methodology for estimating VaR. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. See additional discussion under commodity price risk in the Risk Management section.

Risk Factors

Risk is inherent in all business activities and cannot be entirely eliminated. However, shareholder value can be maintained and enhanced by identifying, mitigating, and where possible, insuring against these risks.

The following section addresses some, but not all, risk factors that could affect our future results and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

Certain sections will show the after-tax effect on net earnings and/or cash flows of changes in certain key variables. The analysis is based on business conditions and production volumes in 2008. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes.

Volume Risk

Volume risk relates to the variances from our expected production. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

Our hydro operations' financial performance is partially dependent upon the availability of water in a given year. The availability of water is difficult to forecast as it is primarily driven by weather. Such water availability introduces a degree of volatility in revenues earned by our hydro operations from year to year. This risk is complicated by obligations imposed within the PPA applicable to our Alberta hydro facilities. A monthly financial obligation must be paid to the PPA Buyer, based on a predetermined quantity of energy and ancillary services at market prices, regardless of our ability to generate such quantities. We carefully balance all of these factors together to achieve optimal productivity with the water resources available.

Our wind and geothermal operations are dependant upon the availability of wind and geothermal resources.

We manage these risks by:

- actively managing our assets and their condition through the Generation and Generation Technology groups in order to be proactive in plant maintenance,
- monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities,
- placing our wind and geothermal facilities in locations that we believe to have sufficient resources in order for us to be able to generate sufficient electricity to meet the requirements of contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require, and
- monitoring market volumes and liquidity to ensure sufficient volumes are available to fulfill proprietary trading requirements.

The sensitivities of volumes to our net income are described below:

Factor	**Increase or decrease**	**Approximate impact on earnings and cash flow (after-tax)**
Availability/production	1%	$ 21

Generation Equipment and Technology Risk

Our plants are exposed to operational risks such as fatigue cracks in boilers, corrosion in boiler tubing, turbine failures, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we must either compensate the purchaser for the loss in the availability of production or record reduced electrical or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period with our equipment unavailable to produce electricity.

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the output of our generating facilities for the longest period of time,
- performing preventative maintenance on a regular basis,
- adhering to a comprehensive plant maintenance program and regular turnaround schedules,
- having sufficient business interruption insurance in place in the event of an extended outage,
- having force majeure clauses in the PPAs and other long-term contracts,
- using technology in our generating facilities that is selected and maintained with the goal of maximizing the return on those assets,
- monitoring technological advances and evaluating their impact upon our existing generating fleet and related maintenance programs,
- negotiating strategic supply agreements with selected vendors to ensure key components are available in the event of a significant outage, and
- developing a long-term asset management strategy with the objective of maximizing the life cycles of our existing facilities and/or replacement of selected generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam and other services are provided,
- entering into a variety of short- and long-term contracts to minimize our exposure to short-term fluctuations in electricity prices,
- purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit, and
- ensuring limits and controls are in place for our proprietary trading activities to ensure they are in line with VaR methodologies. VaR is the primary measure used to manage COD's exposure to market risk resulting from trading activities.

In 2008, we had approximately 97 per cent of production under short-term and long-term contracts and hedges (2007 96 per cent). In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts.

We manage fuel price commodity risk by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants, and
- using hedges, where available, to set prices for fuel.

We are exposed to increases in the cost of fuels used in production to the extent such increases are greater than the increases in the price that we can obtain for the electricity we produce. In 2008, 82 per cent (2007 81 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2007 100 per cent) of our purchased coal costs were contractually fixed.

We monitor the market for opportunities to enter into favourably priced long-term gas contracts.

The sensitivities of price changes to our net income are described below:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Electricity price	$ 1.00/MWh	$ 9
Natural gas price	$ 0.10/GJ	$ 1
Coal price	$ 1.00/tonne	$ 15

Fuel Supply Risk

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. The ability to have sufficient fuel available when required for generation could have an impact upon our ability to produce electricity under contracts and for merchant sale opportunities.

At Alberta Thermal, higher input costs, such as diesel, tires, the price of mining equipment, increased amounts of overburden being removed to access coal reserves, and mining operations moving further away from the power plants are all contributing to increased mining costs. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At Centralia Thermal, interruptions at our suppliers' mines and the availability of trains to deliver coal could affect our ability to generate electricity.

We manage fuel supply risk by:

- ensuring that the majority of the coal used in electrical generation is from coal reserves owned by us, thereby limiting our exposure to fluctuations in the supply of coal from third parties. As at Dec. 31, 2008, approximately 70 per cent (2007 70 per cent) of the coal used in generating activities is from coal reserves owned by us,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at Centralia Thermal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- ensuring sufficient trains to deliver the coal requirements at Centralia Thermal, and
- ensuring efficient coal handling and storage facilities are in place to ensure that the coal being delivered can be processed in a timely and efficient manner.

We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

Environmental Risk

Environmental risks are risks to our business associated with changes in environmental regulations or exposures. New emission reduction objectives for the power sector are being established by governments in Canada and the United States. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by imposing additional costs on the generation of electricity, such as emission caps, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these costs will increase due to increased political and public attention to environmental concerns.

We manage environmental risk by:

- seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,
- having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety ("EHS") management system in place that is designed to continuously improve environmental performance,
- committing significant effort to work with regulators in Canada and the United States to ensure regulatory changes are well-designed and cost-effective,
- developing compliance plans that address how to meet or exceed emission standards for greenhouse gases, mercury, sulphur dioxide and oxides of nitrogen, which will be adjusted as regulations are finalized,
- purchasing emission reduction offsets outside of our operations,
- investing in renewable energy projects, such as wind generation, and
- investing in clean coal technology development, which provides long-term promise for large emission reductions from fossil-fired generation.

We strive to maintain compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to our Board of Directors.

In 2008, we spent approximately $47 million (2007 $46 million) on environmental management activities, systems and processes.

We are a founder of the Canadian Clean Power Coalition, which is an industry consortium developed to build Canada's first clean coal power plant. In March 2008, the Alberta government announced its plan to provide funding of $2 billion for new CCS projects operational before 2015. We have submitted a proposal for funding of our Project Pioneer CCS project and has been short-listed. The Alberta government will announce its funding allocation in July 2009.

Credit Risk

Credit risk is the risk to our business associated with changes in creditworthiness of entities with which we have commercial exposures. This risk is in the ability of a counterparty to either fulfill their financial obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on creditworthiness of counterparties, define contract term limits, and credit concentration with any specific counterparties,
- using formal sign-off on contracts that include commercial, financial, legal, and operational reviews,
- using security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfill their obligation or go over their limits, and
- reporting our exposure using a variety of methods that allow key decision makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure such as requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

We took steps throughout 2008 to reduce our counterparty risk by proactively assessing the effect of the potential changes in the financial markets on counterparty risk and acting on these assessments. While we had no counterparty losses in 2008, we are continuing to keep a close watch on changes and trends in the market and the impact these changes could have on our trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

We are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. Our credit risk management profile and practices have not changed materially from Dec. 31, 2007.

A summary of our credit exposure for commodity trading operations and hedging at Dec. 31, 2008 is provided below:

Counterparty credit rating		**Net exposure**
Investment grade	$	350
Non-investment grade	$	47
No external rating, internally rated as investment grade	$	39
No external rating, internally rated as non-investment grade	$	6

The maximum credit exposure to any one customer for commodity trading operations, excluding the California Independent System Operator and California Power Exchange, and including the fair value of open trading positions, is $105 million (2007 $6 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, and the acquisition of equipment and services from foreign suppliers. We have exposures primarily to the U.S and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged.

We manage our currency rate risk by:

- hedging our net investments in foreign operations using a combination of foreign-denominated debt and financial instruments. Our strategy is to offset 90 to 100 per cent of all foreign currency exposures. At Dec. 31, 2008, we have hedged approximately 97 per cent (2007 99 per cent) of our foreign currency net investment exposure, and
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies. We use financial instruments to hedge the balance of our exposure in foreign operations earnings.

Translation gains and losses related to the carrying value of our foreign operations are included in accumulated OCI in shareholders' equity. At Dec. 31, 2008, the balance in this account was a $61 million gain (2007 $245 million loss).

The sensitivity of changes in foreign exchange rates upon our earnings is shown below:

Factor	Increase or decrease (foreign currency)	Approximate impact on earnings and cash flow (after-tax)
Exchange rate	$ 0.10	$ 10

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used in proprietary trading activities, commodity contracting, and in debt and equity markets. Investment grade ratings support contracting activities and provide better access to capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings.

We are exposed to liquidity risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require us to provide collateral when the fair value of these contracts is in excess of any credit limits granted by our counterparties and the contract obliges us to provide the collateral. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and accordingly increase the amount of collateral we may have to provide.

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,
- reporting liquidity risk exposure for proprietary trading activities on a regular basis to the EMC, senior management, and Board of Directors, and
- maintaining investment grade credit ratings.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our Alberta PPA plants. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

We manage interest rate risk by:

- employing a combination of fixed and floating rate debt instruments, and monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2008, approximately 24 per cent (2007 35 per cent) of our total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

The sensitivity of changes in interest rates upon our earnings is shown below:

Factor	**Increase or decrease**	**Approximate impact on earnings and cash flow (after-tax)**
Interest rate	1%	$ 5

Project Management Risk

As we are currently building six generating projects, we face risks associated with cost-overruns, delays, and performance.

We attempt to minimize these project risks by:

ensuring all projects are vetted by the Technical, Risk and Commercial Team ("TRACT") Committee so that projects have been highly scrutinized to see that established processes and policies are followed, risks have been properly identified and quantified, input assumptions are reasonable, and returns are realistically forecasted prior to Executive and Board approvals,

using a consistent and disciplined project management methodology and processes,

performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction,

partnering with those who have previously been able to deliver projects economically and on budget. Our partnership with EPCOR on the construction of Keephills 3 is a direct result of this type of partnership,

developing and following through with comprehensive plans that include critical paths identified, key delivery points, and backup plans,

ensuring project closeouts so that any learnings from the project are incorporated into the next significant project, fixing the price and availability of the equipment, foreign currency rates, warranties and source agreements as much as economically feasible prior to proceeding with the project, and

entering into labour agreements to provide security around cost and productivity.

Human Resource Risk

Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

potential disruption as a result of labour action at our generating facilities,

reduced productivity due to turnover in positions,

inability to complete critical work due to vacant positions,

failure to maintain fair compensation with respect to market rate changes, and

reduced competencies due to insufficient training, failure to transfer knowledge from existing employees, or insufficient expertise within current employees.

We manage this risk by:

monitoring industry compensation and aligning salaries with those benchmarks,

using incentive pay to align employee goals with corporate goals,

monitoring and managing target levels of employee turnover, and

ensuring new employees have the appropriate training and qualifications to perform their jobs.

Of our labour force, 46 per cent (2007 46 per cent) is covered by 11 (2007 13) collective bargaining agreements. In 2008, three (2007 eight) agreements were renegotiated. We anticipate negotiating five agreements in 2009. We do not anticipate any significant issues in the renewal of these agreements.

Regulatory and Political Risk

Regulatory and political risk describes the risk to our business associated with existing regulatory structures and the political influence upon those structures. The generation of electricity is under increased political scrutiny due to decreasing reserve margins, increased demand, and a lack of new generating capacity. This risk can come from market re-regulation, increased oversight and control, or other unforeseen influences. We are not able to predict whether there will be any changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business.

We manage these risks by working with governments, regulators, and other stakeholders to resolve issues. We are active in policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer-term.

International investments are subject to unique risks and uncertainties relating to the political, social, and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and political risk insurance.

Transmission Risk

Access to transmission lines and sufficient capacity in those transmission lines are key in our ability to deliver power to our customers. However, with the continued growth in demand for electricity coupled with very little transmission capacity being added to existing infrastructures, the reliability and capacity on the existing transmission facilities, the risk associated with the existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continues to develop.

Transmission risks are mitigated through:

- force majeure clauses in the Alberta PPAs,
- developing and ensuring continued access to multiple transmission lines, and
- working with governments, regulators, and stakeholders to ensure that transmission constraints are removed through timely transmission development or technology additions.

Reputation Risk

Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, and other entities.

We manage reputation risk by:

- striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders,
- clearly communicating our business objectives and priorities to a variety of stakeholders on a routine basis,
- maintaining positive relationships with various levels of government,
- pursuing sustainable development as a longer-term corporate strategy,
- ensuring that each business decision is made with integrity and in line with our corporate values, and
- communicating the impact and rationale of business decisions to stakeholders in a timely manner.

We are dedicated to operating a safe and ethical organization. We have a system in place where employees may report any potential ethical concerns. These concerns are directed to the Vice-President Internal Audit who engages Corporate Security, Legal, and Human

Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the Audit and Risk Committee. All employees and directors are required to sign a corporate code of conduct on an annual basis.

Corporate Structure Risk

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by our subsidiaries in the form of distributions, loans, dividends, or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of PP&E, results of financing efforts, credit risk, and counterparty risk.

Income Taxes

Our operations are complex, and located in different countries. The computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by GAAP, based on all information currently available.

The sensitivity of changes in income tax rates upon our earnings is shown below:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Tax rate	1%	$ 4

The effective income tax rate can change depending on the mix of earnings from various countries. Increased operating income will incur income tax expense at a rate of approximately 29 per cent compared to the forecasted overall range of 20 to 25 per cent.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings which arise during the normal course of our business. We review 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 our favour, we do not believe that the outcome of any claims or potential claims of which we are currently aware will have a material adverse effect on us, taken as a whole.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 2008. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that insurance proceeds received by the Corporation for any loss or damage will be fully adequate to compensate for potential losses incurred.

Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our significant accounting policies are described in Note 1 to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, PP&E, goodwill, asset retirement obligations, income taxes, employee future benefits, and financial instruments (Notes 1(D), (F), (G), (I), (K), (L), and (N) respectively). Each policy involves a number of estimates and assumptions to be made about matters that are highly uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our A&R Committee and our independent auditors. The A&R Committee has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

Tables are provided in the following discussion to reflect the sensitivities associated with changes in key assumptions used in the estimates. The tables reflect an increase or decrease in the percentage or other factor for each assumption. The inverse of each change is generally expected to have a similar opposite impact. Each separate item in the sensitivity assumes all other factors remain constant.

These critical accounting estimates are described below.

Revenue Recognition

The majority of our revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, availability incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each of these components is recognized upon output, delivery, or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments for each MWh produced at market prices and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts and futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting and are presented on a net basis in the statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as risk management assets or liabilities. The fair value of derivative contracts receiving hedge accounting treatment open at the balance sheet date are deferred in OCI and are presented on the balance sheets as risk management assets or liabilities.

The determination of the fair value of Energy Trading contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility, and liquidity, among other factors. The majority of derivatives traded by us have quoted market prices or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives have been determined using valuation techniques or models.

Financial Instruments

The fair value of financial instruments are determined and classified within three categories, which are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value.

Level I

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

Level II

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

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers in Level II. Level II fair values also include fair values determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of Other Risk Management Assets and Liabilities, the Corporation uses inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third party information such as credit spreads. In 2008, the majority of our Level I financial instruments were reclassified as Level II, which is consistent with industry practice for similar valuation techniques.

Level III

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

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III fair values are determined would not result in materially different fair values.

Valuation of PP&E

As at Dec. 31, 2008, PP&E makes up 77 per cent of our assets, of which 99 per cent relates to the Generation segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors which could indicate that impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner or use of the assets, the strategy for our overall business, and significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our businesses, the markets, and the business environment are continually monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of the future undiscounted cash flows from the asset. If the total of the undiscounted future cash flows (excluding financing charges, with the exception of plants that have specifically dedicated debt), is less than the carrying amount of the asset, an asset impairment charge must be recognized in our financial statements. The amount of the impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is best estimated by calculating the net present value of future expected cash flows related to the asset. Both the identification of events that may trigger an impairment and the estimates of future cash flows and the fair value of the asset require considerable judgment.

The assessment of asset impairment requires management to make significant assumptions about future sales prices, cost of sales, production and fuel consumed over the life of the plants (up to 30 years), retirement costs, and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any change accounted for prospectively.

In estimating future cash flows of the plants, we use estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. Actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

On an annual basis, or as events indicate, we perform an impairment review of our plants. As a result of this review, in 2008, there were no material changes. In 2006, we recorded an impairment charge for the Centralia Gas plant as the full book value of this plant was unlikely to be recovered from future cash flows due to changes in outlook for dispatch rates and trading values and their impact on plant profitability. Refer to the Significant Events section of this MD&A for further details.

As a result of the decision to cease mining activities at the Centralia coal mine, we wrote down mining and reclamation equipment as well as mining infrastructure to the lower of net book value and fair value. Refer to the Significant Events section of this MD&A for further details.

In 2005, we determined that the Ottawa plant was impaired in the accounts of TA Cogen. A fundamental shift in the gas markets and forecast increases in the cost of natural gas lowered expected margins from the Ottawa plant as TA Cogen does not have a gas supply contract in place for the period 2008-2012 to match the contract to provide electricity under predetermined prices to the OEFC. Based upon the current view of gas costs and market conditions for that period and the likelihood that the plant will not operate as extensively beyond 2012, a reduction in the carrying value was required and a charge of $36 million was recognized in 2005.

Asset Retirement Obligations

We recognize ARO for PP&E in the period in which they are incurred if there is a legal obligation for us to reclaim the plant and/or site and if a reasonable estimate of a fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many ARO. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

At Dec. 31, 2008, the ARO recorded on the consolidated balance sheets were $297 million. We estimate the undiscounted amount of cash flow required to settle the ARO is approximately $0.8 billion, which will be incurred between 2009 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent was used to calculate the carrying value of the ARO.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Discount rate	1%	$ 2
Undiscounted ARO	1%	$

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives were determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. Major components of plants are depreciated over their own useful lives. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year.

Depreciation and amortization expense was $428 million in 2008, of which $32 million relates to mining equipment, and is included in fuel and purchased power.

The rates used are reviewed on an ongoing basis to ensure they continue to be appropriate, and are also reviewed in conjunction with impairment testing, as discussed above.

A five per cent change in the estimated useful life of depreciable assets will result in a change of $22 million in depreciation and amortization expense (2007 $20 million).

Valuation of Goodwill

We evaluate goodwill for impairment at least annually or more frequently if indicators of impairment exist. If the carrying value of a reporting unit, including goodwill, exceeds the reporting unit's fair value, any excess represents a goodwill impairment loss. A reporting unit is a portion of the business for which we can identify specific cash flows.

Goodwill was recorded on the acquisitions of Merchant Energy Group of the Americas, Vision Quest, and CE Gen. At Dec. 31, 2008, this goodwill had a total carrying value of $142 million. The change in value from Dec. 31, 2007 is due to changes in foreign exchange rates related to CE Gen, which is denominated in U.S. dollars. The change in foreign exchange rates related to the translation of self-sustaining foreign operations does not affect earnings and the cumulative translation gain is reflected in AOCI.

We reviewed the recorded value of goodwill prior to year-end and determined that the fair values of our reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values. There were no significant events that impacted the fair values of the reporting units between the time of our testing and Dec. 31, 2008. This includes consideration of the current economic environment and related credit crisis, which does not impact the fair value of our assets and liabilities of our reporting units because they are contracted. Accordingly, no goodwill impairment charges were recorded for the year ended Dec. 31, 2008.

Determining the fair value of the reporting units is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins and fuel and operating costs. Had assumptions been made that resulted in fair values of the reporting units declining by 10 per cent from current levels, there would not have been any impairment of goodwill.

Income Taxes

In accordance with Canadian GAAP, we use the liability method of accounting for future income taxes and provide future income taxes for all significant income tax temporary differences.

Preparation of the consolidated financial statements requires an estimate of income taxes in each of the jurisdictions in which we operate. The process involves an estimate of our current tax exposure and an assessment of temporary differences resulting from differing treatment of items, such as depreciation and amortization, for tax and accounting purposes. These differences result in future tax assets and liabilities that are included in our consolidated balance sheets.

An assessment must also be made to determine the likelihood that our future tax assets will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance must be determined. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Future tax assets of $251 million have been recorded on the consolidated balance sheets at Dec. 31, 2008 (2007 $343 million). These assets are comprised primarily of unrealized losses from risk management transactions, asset retirement obligation costs, and net operating and capital loss carryforwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these deductions and carryforwards in the tax jurisdictions where they exist.

Future tax liabilities of $610 million have been recorded on the consolidated balance sheets at Dec. 31, 2008 (2007 $649 million). These liabilities are comprised primarily of unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Judgment is required to assess continually changing tax interpretations, regulations and legislation, to ensure liabilities are complete and to ensure assets, net of valuation allowances, are realizable. The impact of different interpretations and applications could be material.

Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes based on all information currently available. The outcome of the audits is not known nor is the potential impact on the financial statements determinable.

Employee Future Benefits

We provide selected post-retirement benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liability for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The discount rate used reflects high-quality fixed income securities currently available and expected to be available during the period to maturity of the pension benefits. We do not expect to make any changes to the rate in 2009.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. For the year ended Dec. 31, 2008, the plan assets had a negative return of $55 million compared to a positive return of

$10 million in 2007 and $35 million in 2006. The 2008 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2007 and 2006.

Current Accounting Changes

Financial Instruments Disclosures and Presentation

On Jan. 1, 2008, we adopted two new accounting standards: Handbook Section 3862, *Financial Instruments Disclosures* and Handbook Section 3863, *Financial Instruments Presentation*. 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.

Embedded Foreign Currency Derivatives

On Jan. 8, 2008, the CICA Emerging Issues Committee ("EIC") issued EIC-169 *Determining Whether a Contract is Routinely Denominated in a Single Currency*. The EIC is intended to provide guidance on when an embedded foreign currency derivative would require bifurcation from a host contract. EIC-169 became effective for us on Jan. 1, 2008 and its implementation did not have a material impact upon the consolidated financial position or results of operations.

Employee Future Benefits

During 2008, we assessed the accounting treatment for the amortization of the past service costs and actuarial gains and losses on defined benefit plans. In prior years, the past service costs and actuarial gains and losses on defined benefit plans had been amortized using the Estimated Average Remaining Service Life ("EARSL"), which is determined by the actuary as seven years. As a result of the assessment, we have amortized the past service costs and actuarial gains and losses on defined benefit plans under Canadian GAAP using the Estimated Average Remaining Life ("EARL") for plans whose members are almost all retired, which is determined by the actuary as 17 years. As the members of the Canadian Registered Plan are now almost all inactive, starting in 2008 the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets will be amortized over EARL.

We adopted this method of amortization on Jan. 1, 2008 and its implementation had no material effect on previously reported amounts. This method has not been applied to the Centralia plan as it did not qualify because its members are not almost all retired. The U.S. plan continues to be amortized using EARSL.

Reclassification of Fair Values

In order to be consistent with practices developed over 2008, we have reclassified over-the-counter derivatives with fair values based upon observable commodity futures curves, and derivatives with inputs validated by broker quotes, from Level I to Level II. During 2008, we had previously reported these as Level I. This reclassification did not affect our financial position or earnings.

Recognition of a Tax Loss Carryforward

On Aug. 28, 2008 the CICA EIC issued EIC-172 *Income Statement Presentation of a Tax Loss Carryforward Recognized Following an Unrealized Gain Recorded in Other Comprehensive Income*. The EIC is intended to provide guidance on whether the tax benefit from the recognition of tax loss carryforwards consequent to the recording of unrealized gains in OCI, such as unrealized gain on available-for-sale financial assets, should be recognized in net earnings or in OCI. EIC-172 became effective for us on Sept. 30, 2008 and its implementation did not impact the consolidated financial position or results of operations.

Future Accounting Changes

Credit Risk

On Jan. 20, 2009, the CICA EIC issued EIC-173 *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC-173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. We will adopt the requirements of EIC-173 effective Jan. 1, 2009. Its implementation is not expected to have a material impact upon our consolidated financial position or results of operations.

Business Combinations and Non-Controlling Interests Financial Accounting Standard ("FAS") 141(R) and FAS 160

The Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board ("IASB") have developed common standards on Business Combinations and Non-Controlling Interests. The primary objective was to develop a single set of high-quality standards of accounting for business combinations that could be used for both domestic and cross-border financial reporting. These standards propose significant changes with respect to accounting for business combinations, as well as the accounting and reporting of non-controlling interests in consolidated financial statements.

The Boards have completed re-deliberations, and issued final standards in the fourth quarter of 2007 (IASB issued standards in January 2008), that will be effective for us on Jan. 1, 2009. FASB issued Statement No. 141(R), *Business Combinations* a replacement of FASB Statement No. 141, and Statement No. 160, *Non-Controlling Interests in Consolidated Financial Statements* an amendment of ARB No. 51, in conjunction with the IASB standards. We are currently assessing the impact of adopting the above standards on the consolidated financial position and results of operations.

Deferral of Costs and Internally Developed Intangibles

In November 2007, the Accounting Standards Board ("AcSB") approved Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 incorporates material from IAS 38, *Intangible Assets*, addressing when an internally developed intangible asset meets the criteria for recognition as an asset. The AcSB also approved amendments to Accounting Guideline AcG-11, *Enterprises in the Development Stage* which provides consistency with Section 3064. EIC-27, *Revenues and Expenditures during the Pre-Operating Period*, will not apply to entities that have adopted Section 3064. These changes are effective for us on Jan. 1, 2009, and its implementation is not expected to have a material impact upon the consolidated financial position or results of operations.

International Financial Reporting Standards ("IFRS")

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. On Feb. 13, 2008, the AcSB confirmed that the use of IFRS will be required for interim and annual financial statements on Jan. 1, 2011, with appropriate comparative financial data for 2010. Under IFRS, there is significantly more disclosure required, specifically for interim reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy that must be addressed.

Our project to convert to IFRS for January 1, 2011 commenced in 2007 and consists of four phases: diagnostic, design and planning, solution development, and implementation. The diagnostic phase has been completed.

The project has entered the design and planning stage with issue-specific teams being established to further analyze the key areas of convergence and coordinate with Information Technology and Internal Control resources to determine process and system changes along with appropriate financial reporting controls. Staff training programs are also in the design and planning stages and a communication plan is in place.

The full impact of adopting IFRS on our future financial position and future results cannot be reasonably determined at this time. We are carefully evaluating the transitional options available under IFRS at the adoption date as well as the most appropriate long-term accounting policies.

Our preliminary view is that there are many similarities between Canadian GAAP and IFRS and that the major differences for us will likely arise in respect of property, plant, and equipment, the impairment of long-lived assets, and accounting for long-term contracts.

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

Non-GAAP Measures

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

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

Net Earnings Reconciliation

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

Year ended Dec. 31	**2008**	2007	2006
Gross margin	**$ 1,617**	$ 1,544	$ 1,491
Operating expenses	**(1,084)**	(1,003)	(1,012)

Operating income before mine closure and asset impairment charges	**533**	541	479
Mine closure charges			(192)
Asset impairment charges			(130)
Operating income	**533**	541	157
Foreign exchange (loss) gain	**(12)**	3	(1)
Gain on sale of equipment	**5**	16	
Net interest expense	**(110)**	(133)	(168)
Equity loss	**(97)**	(50)	(17)
Earnings (loss) before non-controlling interests and income taxes	**319**	377	(29)
Non-controlling interests	**61**	48	52
Earnings before income taxes	**258**	329	(81)
Income tax expense (recovery)	**23**	20	(126)
Net earnings	**$ 235**	$ 309	$ 45

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results.

In calculating comparable earnings for 2008, we have excluded the writedown of our Mexican investment as this is a one-time event.

The change in life of certain component parts at Centralia Thermal was also excluded from the calculation of comparable earnings as it is related to the cessation of mining activities at the Centralia coal mine and conversion to consuming solely third party supplied coal. Additionally, we excluded the gains recorded on the sale of assets in 2007 and 2008 at the previously operated Centralia coal mine as we do not normally dispose of large quantities of fixed assets.

In calculating comparable earnings for all three years, we have excluded the impact of tax rate changes, the resolution of outstanding uncertain tax positions, and the tax law change in Mexico as they do not relate to the earnings in the period in which they have been reported.

In arriving at comparable earnings for 2006 we have excluded the turbine impairment charge recorded in the first quarter of 2006.

Earnings on a comparable basis are reconciled to net earnings below:

Year ended Dec. 31	**2008**	**2007**	**2006**
Net earnings	**$ 235**	$ 309	$ 45
Sale of assets at Centralia	**(4)**	(10)	
Change in life of Centralia parts, net of tax	**12**	3	
Change in tax law in Mexico		28	
Tax rate change		(48)	(55)
Turbine impairment, net of tax			6
Recovery from resolution of uncertain tax positions	**(15)**	(18)	
Centralia Gas impairment, net of tax			84
Centralia Coal writedown, net of tax			154
Investments writedown, net of tax	**62**		
Earnings on a comparable basis	**$ 290**	$ 264	$ 234
Weighted average common shares outstanding in the period	**199**	202	201
Earnings on a comparable basis per share	**$ 1.46**	$ 1.31	$ 1.16

Free Cash Flow

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 payment of Centralia coal mine closure costs have also been excluded as they are one-time in nature. Sustaining capital expenditures for the year ended Dec. 31, 2008, represents total capital expenditures per the statement of cash flow less $541 million ($515 million net of joint venture contributions) that we have invested in growth projects.

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

Year ended Dec. 31	**2008**	**2007**	**2006**
Cash flow from operating activities	**$ 1,038**	$ 847	$ 490
Add (Deduct):			
Sustaining capital expenditures	**(465)**	(417)	(214)
Dividends on common shares	**(212)**	(205)	(134)
Distribution to subsidiaries' non-controlling interest	**(98)**	(87)	(74)
Non-recourse debt repayments	**(28)**	(47)	(51)
Timing of contractualy scheduled payments	**(116)**		185

Centralia closure costs		24	
Cash flows from equity investments	**2**	(4)	28
Free cash flow	**$ 121**	$ 111	$ 230

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

Comparable Return on Capital Employed

Comparable ROCE measures economic value created from capital investments and is calculated by taking comparable earnings before tax and dividing by total assets less current liabilities. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods.

The calculation of comparable earnings before tax is presented below:

Year ended Dec. 31	**2008**	2007	2006
Earnings (loss) before income taxes as per statement of earnings	**$ 258**	$ 329	$ (81)
Net interest expense	**110**	133	168
Non-controlling interest	**61**	48	52
Mine closure charges and inventory writedown, pre-tax			236
Asset impairment charges, pre-tax			130
Turbine impairment, pre-tax			10
Change in life of Centralia parts, pre-tax	**18**	6	
Sale of assets at Centralia, pre-tax	**(6)**	(15)	
Change in tax law in Mexico		28	
Investments writedown, pre-tax	**97**		
Comparable earnings, pre-tax	**$ 538**	$ 529	$ 515

Selected Quarterly Information

	Q1 2008	**Q2 2008**	**Q3 2008**	**Q4 2008**
Revenue	**$ 803**	**$ 708**	**$ 791**	**$ 808**
Net earnings	**33**	**47**	**61**	**94**
Basic earnings per common share	**0.17**	**0.24**	**0.31**	**0.47**
Diluted earnings per common share	**0.17**	**0.24**	**0.31**	**0.47**

	Q1 2007	**Q2 2007**	**Q3 2007**	**Q4 2007**
Revenue	$ 669	$ 612	$ 711	$ 783
Net earnings	56	57	66	130
Basic earnings per common share	0.28	0.28	0.33	0.64
Diluted earnings per common share	0.28	0.28	0.33	0.64

Controls and Procedures

As required by Rule 13a-15 under the *Securities Exchange Act* of 1934 ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2008, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Forward-Looking Statements

This document, documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made. In some cases, forward-looking statements can be identified by terms such as "may", "will", "believe", "expect", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from those projected. Some of the risks, uncertainties, and factors include, but are not limited to electricity demand and generation capacity, plant availability, cost and availability of fuel necessary for the production of electricity, legislative and regulatory developments, costs associated with environmental compliance, overall costs, competition, global capital markets activity, changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where we operate, results of financing efforts, changes in counterparty risk and the impact of accounting policies issued by Canadian and U.S. standard setters. Given these uncertainties, readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date hereof or otherwise, and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws.

Management 's Report

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, the Corporation has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures, and established policies provide reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board carried out its responsibility principally through its Audit and Risk Committee. The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors, and external auditors to discuss internal controls, auditing matters, and financial reporting issues. Internal and external auditors have full and unrestricted access to the Audit and Risk Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.

STEPHEN G. SNYDER
President & Chief Executive Officer
March 4, 2009

BRIAN BURDEN
Executive Vice-President & Chief Financial Officer

Management 's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the *United States Securities Exchange Act* of 1934).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta.

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO framework is a suitable framework for its evaluation of TransAlta Corporation's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta Corporation's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta Corporation's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper overrides. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process, and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

TransAlta Corporation's Consolidated Financial Statements include the accounts of the Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures via proportionate consolidation in accordance with Canadian GAAP. Management does not have the contractual ability to assess the internal controls of these joint ventures. Once the financial information is obtained from the joint ventures it falls within the scope of TransAlta Corporation's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of the joint ventures. The 2008 Consolidated Financial Statements of TransAlta Corporation included $1,680 million and $747 million of total and net assets, respectively, as of Dec. 31, 2008, and $481 million and $53 million of revenues and net earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at Dec. 31, 2008, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta Corporation for the year ended Dec. 31, 2008, has also issued a report on internal control over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States). This report is located on Page 68 of this Annual Report.

STEPHEN G. SNYDER
President & Chief Executive Officer
March 4, 2009

BRIAN BURDEN
Executive Vice-President & Chief Financial Officer

Independent Auditors' Report on Internal Controls Under Standards of the Public Company Accounting Oversight Board (United States)

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the corporation's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the CE Generation, Sheerness, Wailuku, and Genesee 3 joint ventures, which is included in the 2008 consolidated financial statements of the Corporation and constituted $1,680 million and $747 million of total and net assets, respectively, as of December 31, 2008, and $481 million and $53 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the CE Generation, Sheerness, Wailuku, and Genesee 3 joint ventures.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAlta Corporation as of December 31, 2008 and 2007 and the related consolidated statements of earnings and retained earnings, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated March 4, 2009, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
March 4, 2009

Independent Auditors' Report on Financial Statements

To the Shareholders of TransAlta Corporation

We have audited the consolidated balance sheets of TransAlta Corporation as at December 31, 2008 and 2007 and the consolidated statements of earnings and retained earnings, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2008. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Corporation as at December 31, 2008 and 2007 and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in conformity with Canadian generally accepted accounting principles.

As discussed in Note 2(B) to the consolidated financial statements, in 2007 the Corporation changed its method of accounting for comprehensive income, financial instruments, hedges, and inventories.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 4, 2009 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
March 4, 2009

Consolidated Statements of Earnings and Retained Earnings

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2008**	2007	2006
Revenues	**$ 3,110**	$ 2,775	$ 2,677
Fuel and purchased power *(Notes 1 and 3)*	**(1,493)**	(1,231)	(1,186)
Gross margin	**1,617**	1,544	1,491
Operations, maintenance, and administration	**637**	577	581
Depreciation and amortization	**428**	406	410
Taxes, other than income taxes	**19**	20	21
Operating expenses	**1,084**	1,003	1,012
Mine closure charges *(Note 3)*			192
Asset impairment charges *(Note 4)*			130
Operating income	**533**	541	157
Foreign exchange (loss) gain *(Note 7)*	**(12)**	3	(1)
Gain on sale of equipment *(Note 16)*	**5**	16	
Net interest expense *(Notes 7 and 21)*	**(110)**	(133)	(168)
Equity loss *(Notes 13 and 27)*	**(97)**	(50)	(17)
Earnings (loss) before non-controlling interests and income taxes	**319**	377	(29)
Non-controlling interests *(Note 5)*	**61**	48	52
Earnings (loss) before income taxes	**258**	329	(81)
Income tax expense (recovery) *(Note 6)*	**23**	20	(126)
Net earnings	**$ 235**	$ 309	$ 45
Retained earnings			
Opening balance	**763**	710	866
Common share dividends	**(215)**	(202)	(201)
Shares cancelled under NCIB *(Note 25)*	**(95)**	(54)	
Closing balance	**$ 688**	$ 763	$ 710
Weighted average number of common shares outstanding in the period	**199**	202	201
Net earnings per share, basic and diluted *(Note 24)*	**$ 1.18**	$ 1.53	$ 0.22

See accompanying notes.

Consolidated Balance Sheets

Dec. 31 *(in millions of Canadian dollars)*	**2008**	**2007**
Assets		*(Restated, Note 2)*
Current assets		
Cash and cash equivalents *(Note 7)*	**$ 50**	$ 51
Accounts receivable *(Notes 7, 8, and 31)*	**542**	546
Prepaid expenses	**6**	9
Risk management assets *(Notes 7, 9, and 10)*	**200**	93
Future income tax assets *(Note 6)*	**3**	40
Income taxes receivable	**61**	49
Inventory *(Note 11)*	**51**	30
	913	818
Restricted cash *(Notes 7 and 12)*		242
Investments *(Note 13)*		125
Long-term receivables *(Notes 6 and 14)*	**14**	6
Property, plant, and equipment *(Note 15)*		
Cost	**9,919**	8,593
Accumulated depreciation	**(3,898)**	(3,476)
	6,021	5,117
Assets held for sale, net *(Note 16)*		29
Goodwill *(Notes 17 and 32)*	**142**	125
Intangible assets *(Note 18)*	**213**	209
Future income tax assets *(Note 6)*	**248**	303
Risk management assets *(Notes 7, 9, and 10)*	**221**	122
Other assets *(Note 19)*	**43**	61
Total assets	**$ 7,815**	$ 7,157
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt *(Notes 7 and 20)*	**$ 443**	$ 651
Accounts payable and accrued liabilities *(Note 7)*	**682**	473
Risk management liabilities *(Notes 7, 9, and 10)*	**148**	105
Income taxes payable	**15**	17
Future income tax liabilities *(Note 6)*	**14**	12
Dividends payable	**52**	49
Current portion of long-term debt recourse *(Notes 7 and 21)*	**211**	122
Current portion of long-term debt non-recourse *(Notes 7 and 21)*	**33**	32
Current portion of asset retirement obligations *(Note 22)*	**45**	43
	1,643	1,504
Long-term debt recourse *(Notes 7 and 21)*	**1,889**	1,474
Long-term debt non-recourse *(Notes 7 and 21)*	**232**	209
Asset retirement obligation *(Note 22)*	**252**	233
Deferred credits and other long-term liabilities *(Note 23)*	**122**	101

Future income tax liabilities *(Note 6)*	**596**	637
Risk management liabilities *(Notes 7, 9, and 10)*	**102**	204
Non-controlling interests *(Note 5)*	**469**	496
Common shareholders' equity		
Common shares *(Notes 24 and 25)*	**1,761**	1,781
Retained earnings *(Note 25)*	**688**	763
Accumulated other comprehensive income (loss) *(Note 25)*	**61**	(245)
Total shareholders' equity	**2,510**	2,299
Total liabilities and shareholders' equity	**$ 7,815**	$ 7,157

Contingencies *(Notes 29 and 31)*
Commitments *(Notes 9 and 30)*

Subsequent events *(Note 36)*

On behalf of the Board:

See accompanying notes.	**DONNA SOBLE KAUFMAN** Director	**WILLIAM D. ANDERSON** Director

Consolidated Statements of Comprehensive Income

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2008**	2007	2006
Net earnings	**$ 235**	$ 309	$ 45
Other comprehensive income (loss)			
Gains (losses) on translating net assets of self-sustaining foreign operations	**342**	(196)	4
(Losses) gains on financial instruments designated as hedges of self-sustaining foreign operations	**(356)**	240	(2)
Tax (recovery) expense	**(61)**	25	
(Losses) gains on financial instruments designated as hedges of self-sustaining foreign operations	**(295)**	215	(2)
Gains on translation of self-sustaining foreign operations	**47**	19	2
Gains (losses) on derivatives designated as cash flow hedges	**327**	(57)	
Tax expense (recovery)	**129**	(16)	
Gains (losses) on derivatives designated as cash flow hedges	**198**	(41)	
Deferred foreign exchange losses on translating net assets of self-sustaining foreign operations transferred to net earnings in the current period *(Note 27)*	**(147)**		
Deferred gains on financial instruments designated as hedges of self-sustaining foreign operations transferred to net earnings in the current period *(Note 27)*	**148**		
Tax expense	**9**		
Loss on sale of Mexico reclassified to statement of earnings	**(8)**		
Derivatives designated as cash flow hedges in prior periods transferred to balance sheet in the current period	**8**	1	
Derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period	**91**	25	
Tax expense	**30**	7	
Reclassification of derivatives designated as cash flow hedges	**69**	19	
Other comprehensive income (loss)	**306**	(3)	2
Comprehensive income	**$ 541**	$ 306	$ 47

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2008**	2007	2006
Operating activities			
Net earnings	**$ 235**	$ 309	$ 45
Depreciation and amortization *(Note 32)*	**451**	415	438
Gain on sale of equipment *(Note 16)*	**(5)**	(16)	
Non-controlling interests *(Note 5)*	**61**	48	52
Asset retirement obligation accretion *(Note 22)*	**22**	24	22
Asset retirement costs settled *(Note 22)*	**(37)**	(38)	(29)
Future income taxes (recovered) *(Note 6)*	**1**	(34)	(164)
Unrealized losses (gains) from risk management activities	**12**	26	(32)
Unrealized foreign exchange (gain) loss	**(5)**	(3)	1
Mine closure charges *(Note 3)*			192
Asset impairment charges *(Note 4)*			130
Equity loss *(Notes 13 and 27)*	**97**	50	17
Other non-cash items	**(4)**		7
	828	781	679
Change in non-cash operating working capital balances	**210**	66	(189)
Cash flow from operating activities	**1,038**	847	490
Investing activities			
Additions to property, plant, and equipment	**(1,006)**	(599)	(224)
Proceeds on sale of property, plant, and equipment	**30**	47	29
Proceeds on sale of equity investment *(Notes 13 and 27)*	**332**		
Equity investment *(Notes 13 and 27)*		(20)	226
Restricted cash *(Note 12)*	**248**	57	(333)
Income tax receivable *(Notes 6 and 14)*	**(8)**		
Realized gains on financial instruments	**52**	107	54
Loan to equity investment	**(245)**		
Other *(Note 27)*	**16**	(2)	(13)
Cash flow used in investing activities	**(581)**	(410)	(261)
Financing activities			
(Decrease) increase in short-term debt	**(243)**	289	348
Issuance of long-term debt *(Note 21)*	**502**	30	
Repayment of long-term debt *(Note 21)*	**(308)**	(252)	(397)
Dividends paid on common shares	**(212)**	(205)	(134)
Redemption of preferred securities		(175)	
Funds paid to repurchase common shares under NCIB *(Note 25)*	**(130)**	(75)	
Net proceeds on issuance of common shares *(Note 24)*	**15**	20	13
Decrease in advances to TransAlta Power		6	1
Realized gains on financial instruments	**12**		
Distributions to subsidiaries' non-controlling interests	**(98)**	(87)	(74)

Other		**(5)**		5		
Cash flow used in financing activities		**(467)**		(444)		(243)
Cash flow used in operating, investing, and financing activities		**(10)**		(7)		(14)
Effect of translation on foreign currency cash		**9**		(8)		1
Decrease in cash and cash equivalents		**(1)**		(15)		(13)
Cash and cash equivalents, beginning of year		**51**		66		79
Cash and cash equivalents, end of year	**$**	**50**	$	51	$	66
Cash taxes paid	**$**	**47**	$	75	$	36
Cash interest paid	**$**	**106**	$	142	$	181

See accompanying notes.

Notes to the Consolidated Financial Statements

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

1. Summary of Significant Accounting Policies

A. Description of the Business

TransAlta Corporation ("TransAlta" or "the Corporation"), was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992 after TransAlta Utilities Corporation ("TAU") became a subsidiary. The Corporation has two reportable segments that are supported by a corporate group that provides finance, treasury, tax, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, internal audit, and other administrative support.

The two reportable segments of the Corporation are as follows:

I. Generation

The Generation segment owns coal, gas, wind, geothermal and hydro plants in Canada, the United States, and Australia. It generates its revenues from the sale of electricity, steam, gas, and ancillary services.

II. Commercial Operations & Development ("COD")

The COD segment derives revenues from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. COD also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation.

B. Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP").

The consolidated financial statements include the accounts of TransAlta, all subsidiaries, and the proportionate share of the accounts of joint ventures and jointly controlled corporations.

C. Use of Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, currency exchange rates, inflation levels and commodity prices, changes in economic conditions and legislative and regulatory changes (Notes 7, 9, 10, 15, 17, 18, 21, 22, 29, 33, and 34).

D. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, availability payments or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each is recognized upon output, delivery, or satisfaction of specific targets, all as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each megawatt hour ("MWh") produced at market prices, and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts and futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting and are presented on a net basis in the statements of earnings. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the balance sheets as risk management assets or liabilities.

The majority of derivatives traded by the Corporation have quoted market prices or over-the-counter quotes. However, some derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives have been determined using valuation techniques or models.

E. Inventory

The majority of cost of goods sold as recorded on the statements of earnings reflects the cost of inventory consumed in the generation of electricity. All inventory is carried at the lower of cost and net realizable value and cost is determined using the weighted average cost method.

The cost of internally produced coal inventory is determined using absorption costing which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions. Due to the limited amount of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption.

The cost of natural gas inventory is determined using absorption costing which includes all applicable expenditures and charges incurred in bringing inventory to its existing condition and location.

F. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is stated at original cost at the time of construction, purchase, or acquisition. Original cost includes items such as materials, labour, interest, and other appropriately allocated costs. As costs are expended for new construction, these costs are capitalized as PP&E on the consolidated balance sheets and are subject to depreciation upon commencement of commercial operations. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor parts, are charged to expense as incurred. Certain expenditures relating to replacement of components incurred during major maintenance are capitalized and amortized over the estimated benefit period of such expenditures. A component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

The estimate of the useful life of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the PP&E is depreciated or amortized. These estimates are subject to revision in future periods based on new or additional information. Depreciation and amortization are calculated using straight-line and unit-of-production methods. Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserves.

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are included in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the future costs are included in PP&E or investments. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to expense.

TransAlta capitalizes interest on capital invested in projects under construction. Upon commencement of commercial operations, capitalized interest, as a portion of the total cost of the plant, is amortized over the estimated useful life of the plant.

On an annual basis, and when indicators of impairment exist, TransAlta determines whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors that could indicate an impairment exists, include significant underperformance relative to historical or projected future operating results, significant changes in the manner or use of the assets, significant negative industry or economic trends, or a change in the strategy for the Corporation's overall business. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where TransAlta is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's businesses, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of future undiscounted cash flows from the PP&E. If the total of the undiscounted future cash flows, excluding financing charges with the exception of plants that have specifically dedicated debt, is less than the carrying amount of the PP&E, an asset impairment must be recognized in the financial statements. The amount of the impairment charge to be recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is normally estimated by calculating the present value of expected future cash flows related to the asset.

G. Goodwill

Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of an acquired business. Goodwill is not subject to amortization, but instead is tested for impairment at least annually, or more frequently if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the reporting unit to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting units to which the goodwill relates is compared to the carrying values of the reporting units. The Corporation determined that the fair values of the reporting units, exceeded their carrying values as at Dec. 31, 2008 and 2007.

H. Intangible Assets

Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, primarily acquired in the purchase of CE Generation LLC ("CE Gen"), a jointly controlled enterprise *(Note 35)*. Sale contracts are valued at cost and are amortized on a straight-line basis over the remaining applicable contract period, which ranges from one to 24 years.

I. Asset Retirement Obligations ("ARO")

The Corporation recognizes ARO in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The ARO liability is accrued over the estimated time period until settlement of the obligation and the asset is depreciated over the estimated useful life of the asset. Reclamation costs for mining assets are recognized on a unit-of-production basis.

TransAlta has recorded an ARO for all generating facilities for which it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not legally required to remove the structures. TransAlta has recognized legal obligations arising from government legislation, written agreements between entities, and case law. The asset retirement liabilities are recognized when the ARO is incurred. Asset retirement liabilities for coal mines are incurred over time, as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

For active mines, accretion expense is included in fuel and purchased power. However, as the Centralia coal mine is considered inactive, related accretion expense is included as part of depreciation expense. In 2006, $9 million was recorded in fuel expense related to accretion expense incurred at the Centralia coal mine.

J. Investments

On Oct. 8, 2008, the Corporation successfully completed the sale of the Mexican business to InterGen Global Ventures B.V. ("InterGen") *(Notes 13 and 27)*. Prior to the sale, the wholly owned subsidiaries that held TransAlta's interests in the Campeche and Chihuahua power plants were considered Variable Interest Entities ("VIEs") and were shown as equity investments.

Investments in shares of companies over which the Corporation exercises significant influence are accounted for using the equity method. Other investments are carried at cost. If there is other than a temporary decline in the value of an investment, it is written down to net realizable value. There are currently no such investments.

K. Income Taxes

The Corporation uses the liability method of accounting for income taxes for its operations. Under the liability method, income taxes are recognized for the differences between financial statement carrying values and the respective income tax basis of assets and liabilities (temporary differences), and the carryforward of unused tax losses. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is included in earnings in the period the change is substantively enacted. Future income tax assets are evaluated annually and if realization is not considered 'more likely than not', a valuation allowance is provided.

TransAlta's income tax positions are based on research and interpretations of the income tax laws and rulings in each of the jurisdictions in which the Corporation operates. The Corporation's operations are complex, and the computation and provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing and as such, further appeals and audits by taxation authorities may result. The outcome of some audits may change the tax liability of the Corporation. Management believes it has adequately provided for income taxes based on all information currently available.

L. Employee Future Benefits

The Corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets. The cost of pensions and other post-employment and post-retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. The defined benefit pension plans are based on an employee's final average earnings and years of service. The expected return on plan assets is based on expected future capital market returns. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments were amortized on a straight-line basis over the Estimated Average Remaining Service Life ("EARSL") of employees active at the date of amendment. The excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets is amortized over EARSL *(Note 2)*. When the restructuring of a benefit plan gives rise to both a curtailment and settlement of obligations, the curtailment is accounted for prior to the settlement. Transition obligations and assets arising from the prospective adoption of new accounting standards were amortized over EARSL. As the members of the Canadian Registered Plan are now almost all inactive, starting in 2008 the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets will be amortized over the Estimated Average Remaining Life ("EARL"). The U.S. plan continues to be amortized over EARSL.

M. Foreign Currency Translation

The Corporation's functional currency is Canadian dollars while self-sustaining foreign operations' functional currencies are U.S. and Australian dollars.

The Corporation's self-sustaining foreign operations are translated using the current rate method. Translation gains and losses resulting from translating these foreign operations are included in Other Comprehensive Income ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income ("AOCI"). Foreign currency denominated monetary and non-monetary assets and liabilities of self-sustaining foreign operations are translated at exchange rates in effect on the balance sheet date.

Transactions denominated in foreign currencies are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

N. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives, and certain non-financial derivatives are recognized on the consolidated balance sheets when the Corporation becomes a party to the contract. 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. All financial instruments are measured at fair value upon initial recognition except for certain non-financial derivative contracts that meet the Corporation's expected purchase, sale or usage requirements, commonly termed normal purchase / normal sale ("NPNS") contracts. 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. Classification of the financial instrument is determined at inception depending on the underlying exposure that is being hedged.

Financial assets and financial liabilities classified as held for trading are measured at fair value with changes in those fair values recognized in net earnings. Financial assets classified as either held-to-maturity or loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest rate 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 sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. TransAlta recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired, or substantively modified after Jan. 1, 2003. Changes in the fair values of derivative instruments are recognized in net earnings with the exception of the effective portion of (i) derivatives designated as cash flow hedges or

(ii) hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation, which are recognized in OCI. Derivatives used in trading activities are described in more detail in Note 1(D).

Certain financial instruments can be designated as held for trading (the fair value option) on initial recognition even if the financial instrument 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 that are managed and evaluated on a fair value basis in accordance with TransAlta's risk management strategy, and are reported to senior management personnel on that basis.

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. The Corporation uses the effective interest rate method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost. Financial guarantees that meet the definition of a derivative are measured at fair value and are subsequently re-measured at fair value at each balance sheet date.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, 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 Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. For cash flow hedges, the Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options to hedge its exposure to fluctuations in electricity and natural gas prices. The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from anticipated transactions and firm commitments denominated in foreign currencies. To hedge exposure to changes in the carrying value of net investments in foreign operations that are a result of changes in foreign exchange rates, the Corporation primarily uses cross-currency interest rate swaps, foreign currency forward contracts, and foreign currency debts.

To be accounted for as a hedge, a derivative must be designated and documented as a hedge, and must be highly effective at inception and on an ongoing basis. The documentation prepared for the derivative at inception defines all relationships between hedging instruments and hedged items, as well as the Corporation's risk management objective and strategy for undertaking various hedge transactions. The process of hedge accounting includes linking derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or anticipated transactions.

The Corporation also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. To be classified as effective, it is reasonable that the Corporation will fulfill its contractual obligations without having to purchase commodities in the market and cash flow exposure does not exist. If the above hedge criteria are not met, the derivative is accounted for on the balance sheet at fair value, with subsequent changes in fair value recorded in earnings in the period of change. For those instruments that the Corporation does not seek or are ineligible for hedge accounting, changes in fair value are recorded in earnings.

a. Fair Value Hedges

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 is 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. Hedge effectiveness of fair value hedges is achieved if changes in the fair value of the derivative substantially offset changes in the fair value of the item hedged. 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.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. If hedge criteria are met, interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

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. Hedge effectiveness of cash flow hedges is achieved if the derivatives' cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows is similar. 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 from OCI immediately to net earnings when it is probable that the forecasted transaction will not occur within the specified time period.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, as described above, gains and losses on these derivatives are recognized in earnings in the same period and financial statement caption as the hedged exposure. Up to the date of settlement, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from anticipated transactions and firm commitments denominated in foreign currencies. If hedge criteria are met, changes in value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

c. Foreign Currency Exposure of a Net Investment in a Self-Sustaining Foreign Operation Hedges

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.

The Corporation primarily uses cross-currency interest rate swaps, foreign currency forward contracts, and foreign currency debts to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations as a result of changes in foreign exchange rates. Gains and losses on these instruments that qualify for hedge accounting are reported in OCI with fair values recorded in risk management assets or liabilities.

O. Stock-Based Compensation Plans

The Corporation has three types of stock-based compensation plans as described in Note 33. Under the fair value method for stock options, compensation expense is measured at the grant date at fair value and recognized over the service period.

Stock grants under the Performance Share Ownership Plan ("PSOP") are accrued in operations, maintenance, and administration ("OM&A") expense as earned to the balance sheet date, based upon the percentile ranking of the total shareholder return of the Corporation's common shares in comparison to the total shareholder returns of companies comprising the Standard & Poor's ("S&P")/Toronto Stock Exchange ("TSX") Composite Index. Compensation expense under the phantom stock option plan is recognized in OM&A for the amount by which the quoted market price of TransAlta's shares exceed the option price, and adjusted for changes in each period for changes in the excess over the option price. If stock options or stock are repurchased from employees, the excess of the consideration paid over the carrying amount of the stock option or stock cancelled is charged to retained earnings.

P. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

Q. Long-Term Debt

Transaction costs are recorded against the carrying value of long-term debt. The Corporation uses the effective interest rate method of amortization for any transaction costs or fees. The Corporation has chosen to use the effective interest rate method to amortize issuance costs and fees associated with long-term debt. A portion of the debt has been hedged using fixed to floating interest rate swaps and therefore the Corporation has included the fair value of these swaps with the value of the debt.

R. Accounting for Emission Credits and Allowances

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 an emission liability on the balance sheet using the best estimate of the amount required to settle the Corporation's 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.

S. Planned Maintenance

Planned maintenance is performed at regular intervals and the expenditures include both expense and capital portions. The planned major maintenance includes repairs and maintenance of existing components and the replacement of existing components. Repairs and maintenance of existing components are expensed in the period incurred. Costs of replacing existing components are capitalized in the period of maintenance activities and amortized on a straight-line basis over the life of the asset. A component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

2. Accounting Changes

Certain of the comparative figures have been reclassified to conform with the current year's presentation. Such reclassification did not impact previously reported net income or retained earnings.

During 2008, the fair value balances related to interest rate swap unwinds were included as part of recourse debt. In 2007, $22 million was also reclassified in order to present comparable figures.

A. Current Accounting Changes

I. Financial Instruments Disclosures and Presentation

On Jan. 1, 2008, the Corporation adopted two new accounting standards: Handbook Section 3862, *Financial Instruments Disclosures* and Handbook Section 3863, *Financial Instruments Presentation.* 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. Disclosures required as a result of adopting these sections can be found in Note 7.

II. Embedded Foreign Currency Derivatives

On Jan. 8, 2008, the Canadian Institute of Chartered Accountants ("CICA") Emerging Issues Committee ("EIC") issued EIC-169 *Determining Whether a Contract is Routinely Denominated in a Single Currency*. The EIC is intended to provide guidance on when an embedded foreign currency derivative would require bifurcation from a host contract. EIC-169 became effective for TransAlta on Jan. 1, 2008 and its implementation did not have a material impact upon the consolidated financial position or results of operations.

III. Employee Future Benefits

During 2008, TransAlta assessed the accounting treatment for the amortization of the past service costs and actuarial gains and losses on defined benefit plans. In prior years, the past service costs and actuarial gains and losses on defined benefit plans had been amortized using EARSL, which is determined by the actuary as seven years. As a result of the assessment, TransAlta amortized the past service costs and actuarial gains and losses on defined benefit plans under Canadian GAAP using EARL for plans whose members are almost all retired, which is determined by the actuary as 17 years. As the members of the Canadian Registered Plan are now almost all inactive, starting in 2008 the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets will be amortized over EARL.

TransAlta adopted this method of amortization on Jan. 1, 2008 and its implementation had no material effect on previously reported amounts. This method has not been applied to the Centralia plan as it did not qualify because its members are not almost all retired. The U.S. plan continues to be amortized using EARSL.

IV. Reclassification of Fair Values

In order to be consistent with practices developed over 2008, the Corporation has reclassified over-the-counter derivatives with fair values based upon observable commodity futures curves, and derivatives with inputs validated by broker quotes, from Level I to Level II *(Note 9)*. During 2008, the Corporation had previously reported these as Level I. This reclassification did not affect the financial position or earnings of the Corporation.

V. Recognition of a Tax Loss Carryforward

On Aug. 28, 2008 the CICA EIC issued EIC-172 *Income Statement Presentation of a Tax Loss Carryforward Recognized Following an Unrealized Gain Recorded in Other Comprehensive Income*. The EIC is intended to provide guidance on whether the tax benefit from the recognition of tax loss carryforwards consequent to the recording of unrealized gains in OCI, such as unrealized gain on available-for-sale financial assets, should be recognized in net earnings or in OCI. EIC-172 became effective for TransAlta on Sept. 30, 2008 and its implementation did not impact the consolidated financial position or results of operations.

B. Prior Year Accounting Changes

I. Inventories

In March 2007, the CICA issued Section 3031, *Inventories*, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards ("IFRS"). TransAlta early adopted this standard. This standard did not have a material effect on the financial statements.

II. Capital Disclosure

On Dec. 1, 2006, the CICA issued Section 1535, *Capital Disclosures*. TransAlta early adopted this standard and provided the required disclosure in Note 26.

III. General Standards on Financial Statement Presentation

On June 1, 2007, the CICA issued Section 1400, *General Standards on Financial Statement Presentation*. TransAlta early adopted this standard and did not require any additional disclosures.

IV. Financial Instruments

On Jan. 1, 2007, TransAlta 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*. TransAlta adopted these standards retroactively with an adjustment of opening 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 in the Corporation's financial instruments presentation and related disclosure.

V. Comprehensive Income

Section 1530 introduces comprehensive income, which consists of net earnings and 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 consolidated financial statements consolidated statements of comprehensive income. The cumulative changes in OCI are included in AOCI, which is presented as a new category of shareholders' equity on the consolidated balance sheets.

VI. 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 sheets 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 sheets 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 (i) derivatives designated as effective cash flow hedges or (ii) 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 TransAlta's risk management strategy, and are reported to senior management personnel on that basis.

Other significant accounting implications arising upon the adoption of Section 3855 include the use of the effective interest rate 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.

As part of the implementation of Handbook Section 3855, TransAlta selected Jan. 1, 2003 as the transition date with respect to the assessment of embedded derivatives. TransAlta recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantively modified on or after the selected transition date.

VII. 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 the 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.

Prior to the adoption of Section 3865, gains and losses on physical and financial swaps, forward sales contracts, futures contracts and options used to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices related to output from the plants and designated as hedges were recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives were not recorded on the balance sheets. Foreign currency forward contracts used to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies where hedge criteria were met were not recognized on the balance sheets. Interest rate swaps used to manage the impact of fluctuating interest rates on existing debt were not recognized on the balance sheets if they met hedge criteria.

VIII. 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 and (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.

IX. Variable Interest Entities ("VIEs")

On Sept. 15, 2006, the EIC 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.

C. Future Accounting Changes

I. Credit Risk

On Jan. 20, 2009, the CICA EIC issued EIC-173 *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC 173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. TransAlta will adopt the requirements of EIC-173 effective Jan. 1, 2009. Its implementation is not expected to have a material impact upon the consolidated financial position or results of operations.

II. Business Combinations and Non-Controlling Interests FAS 141(R) and FAS 160

The FASB and the IASB have developed common standards on Business Combinations and Non-Controlling Interests. The primary objective was to develop a single set of high-quality standards of accounting for business combinations that could be used for both domestic and cross-border financial reporting. These standards propose significant changes with respect to accounting for business combinations, as well as the accounting and reporting of non-controlling interests in consolidated financial statements.

The Boards have completed re-deliberations, and issued final standards in the fourth quarter of 2007 (IASB issued standards in January 2008), that will be effective for TransAlta on Jan. 1, 2009. FASB issued Statement No. 141(R), *Business Combinations* a replacement of FASB Statement

No. 141, and Statement No. 160, *Non-Controlling Interests in Consolidated Financial Statements* an amendment of ARB No. 51, in conjunction with the IASB standards. The Corporation is currently assessing the impact of adopting the above standards on the consolidated financial position and results of operations.

III. Deferral of Costs and Internally Developed Intangibles

In November 2007, the Accounting Standards Board ("AcSB") approved Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 incorporates material from IAS 38, *Intangible Assets*, addressing when an internally developed intangible asset meets the criteria for recognition as an asset. The AcSB also approved amendments to Accounting Guideline AcG-11, *Enterprises in the Development Stage* which provides consistency with Section 3064. EIC-27, *Revenues and Expenditures during the Pre-Operating Period*, will not apply to entities that have adopted Section 3064. These changes are effective for TransAlta on Jan. 1, 2009, and its implementation is not expected to have a material impact upon the consolidated financial position or results of operations.

IV. International Financial Reporting Standards ("IFRS")

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. On Feb. 13, 2008, the AcSB confirmed that the use of IFRS will be required for interim and annual financial statements on Jan. 1, 2011, with appropriate comparative financial data for 2010. Under IFRS, there is significantly more disclosure required, specifically for interim reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy that must be addressed.

TransAlta's project to convert to IFRS for January 1, 2011 commenced in 2007 and consists of four phases: diagnostic, design and planning, solution development, and implementation. The diagnostic phase has been completed.

The project has entered the design and planning stage with issue-specific teams being established to further analyze the key areas of convergence and coordinate with Information Technology and Internal Control resources to determine process and system changes along with appropriate financial reporting controls. Staff training programs are also in the design and planning stages and a communication plan is in place.

The full impact of adopting IFRS on TransAlta's future financial position and future results cannot be reasonably determined at this time. TransAlta is carefully evaluating the transitional options available under IFRS at the adoption date as well as the most appropriate long-term accounting policies.

TransAlta's preliminary view is that there are many similarities between Canadian GAAP and IFRS and that the major differences for TransAlta will likely arise in respect of property, plant, and equipment, the impairment of long-lived assets, and accounting for long-term contracts.

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

3. Mine Closure Charges

On Nov. 27, 2006, TransAlta ceased mining activities at the Centralia coal mine as a result of increased costs and unfavourable geological conditions. All associated mining and reclamation equipment was written down to the lower of net book value or anticipated realized proceeds. Mine infrastructure, including coal processing equipment and structures, haul roads, and other equipment were written down to anticipated net salvage value. Asset retirement costs, representing the unamortized cost of future reclamation, were also written off. In addition, employee termination costs and other miscellaneous expenses were recorded. The total of these writedowns and provisions before taxes was $192 million.

As a result of the cessation of mining activities, all internally produced coal was also written down to fair market value, which is replacement cost, resulting in an expense of $44 million being recorded in fuel and purchased power. The total amounts are summarized in the table below:

Writedown of coal inventory	$	44
Impact on gross margin		(44)
Mine closure charges		
Mine equipment and infrastructure writedown		72
ARO writedown		81
Severance costs and other		39
Total mine closure charges		192
Loss before income taxes	$	(236)
Income tax recovery		82
Net loss impact of event	$	(154)

As at Dec. 31, 2008 all severance costs and other have been paid.

4. Asset Impairment Charges

For the year ended Dec. 31, 2006, changes in the outlook for dispatch rates and trading values and their impact on plant profitability resulted in the determination that the full book value of the Centralia Gas facility was unlikely to be recovered from future cash flows. As a result, TransAlta recorded a $130 million pre-tax impairment charge to write this plant down to its fair value. This asset is included in the Generation segment.

5. Non-Controlling Interests

A. Statements of Earnings

Year ended Dec. 31		**2008**		**2007**		**2006**
Stanley Power's interest in TA Cogen *(Note 35)*	**$**	**32**	$	29	$	36
25 per cent interest in Saranac Partnership not owned by CE Gen		**29**		19		16
Total	**$**	**61**	$	48	$	52

B. Balance Sheets

As at Dec. 31	**2008**	**2007**

Stanley Power's interest in TA Cogen	**$**	**449**	$	467
25 per cent interest in Saranac Partnership not owned by CE Gen		**20**		29
Total	**$**	**469**	$	496

The change in non-controlling interests is outlined below:

Balance, Dec. 31, 2007	$	496
Distributions paid		(98)
Non-controlling interests portion of net earnings		61
Accrued cash distributions		10
As at Dec. 31, 2008	$	469

6. Income Taxes

The Corporation follows Canadian GAAP for non-regulated entities for all electricity generation operations and as a result, future income taxes have been recorded for all operations.

A. Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2008	2007	2006
Earnings (loss) before income taxes	**$ 258**	$ 329	$ (81)
Equity loss	**(97)**	(50)	(17)
Earnings (loss) before income taxes and excluding equity loss	**$ 355**	$ 379	$ (64)
Statutory Canadian federal and provincial income tax rate (%)	**30**	32	33
Expected taxes (recovery) on income	**105**	121	(21)
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(24)**	(36)	(33)
Asset impairment and mine closure charges recognized at higher tax rate			(9)
Resolution of uncertain tax positions	**(15)**	(18)	
Tax recovery on sale of equity investment *(Note 27)*	**(35)**		
Capital taxes	**1**	2	3
Effect of tax rate changes		(48)	(55)
Statutory and other rate differences	**(7)**	(1)	(4)
Other	**(2)**		(7)
Income tax expense (recovery)	**$ 23**	$ 20	$ (126)
Effective tax rate (%)	**6**	5	197

II. Components of Income Tax Expense (Recovery)

Year ended Dec. 31	2008	2007	2006
Current tax expense	**$ 22**	$ 54	$ 38
Future income tax expense (recovery) related to the origination and reversal of temporary differences	**1**	14	(109)
Future income tax recovery resulting from changes in tax rates or laws		(48)	(55)
Income tax expense (recovery)	**$ 23**	$ 20	$ (126)

B. Balance Sheets

Significant components of the Corporation's future income tax assets (liabilities) are as follows:

As at Dec. 31	2008	2007
Net operating and capital loss carryforwards	**$ 231**	$ 178
Future site restoration costs	**71**	77
Property, plant, and equipment	**(736)**	(717)
Risk management assets and liabilities	**(52)**	75

Employee future benefits and compensation plans		**24**		21
Allowance for doubtful accounts		**22**		18
Other deductible temporary differences		**81**		42
Net future income tax liability	**$**	**(359)**	$	(306)

Presented in the balance sheet as follows:

As at Dec. 31		**2008**		**2007**
Assets				
Current	**$**	**3**	$	40
Long-term		**248**		303
Liabilities				
Current		**(14)**		(12)
Long-term		**(596)**		(637)
Net future income tax liability	**$**	**(359)**	$	(306)

As at Dec. 31, 2008, there were income tax loss carryforwards of nil (2007 $61 million) for which no tax benefit has been recognized.

In 2008, the Corporation received a notice of reassessment from the federal taxation authority related to the disposal of the Transmission Business in the 2002 taxation year. As a result of the reassessment, the Corporation is required to pay approximately $40 million in taxes plus interest and penalties. The Corporation funded a portion of this amount in 2008 by transferring $8 million from its tax prepayment account and anticipates additional cash payments in 2009 to fund the remaining balance. The Corporation is in the process of challenging this reassessment. Since it is anticipated that the dispute will not be resolved within one year, any prepayment transfers and cash paid are recorded as a long-term receivable.

7. Financial Instruments

A. Analysis of Financial Assets and Liabilities by Measurement Basis

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost *(Note 1(N))*. The following table analyses the carrying amounts of the financial assets and liabilities by category:

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

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	$	$	$ **50**	$	$ **50**
Accounts receivable			**542**		**542**
Risk management assets					
Current	**121**	**79**			**200**
Long-term	**220**	**1**			**221**
Financial liabilities					
Short-term debt	$	$	$	$ **443**	$ **443**
Accounts payable and accrued liabilities				**682**	**682**
Risk management liabilities					
Current	**74**	**74**			**148**
Long-term	**96**	**6**			**102**
Long-term debt recourse[1]				**2,100**	**2,100**
Long-term debt non-recourse[1]				**265**	**265**

Carrying value of financial instruments as at Dec. 31, 2007

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	$	$	$ 51	$	$ 51
Accounts receivable			546		546
Risk management assets					
Current	69	24			93
Long-term	122				122
Restricted cash			242		242
Financial liabilities					
Short-term debt	$	$	$	$ 651	$ 651

Accounts payable and accrued liabilities			473	473
Risk management liabilities				
Current	93	12		105
Long-term	191	13		204
Long-term debt recourse[1]			1,596	1,596
Long-term debt non-recourse[1]			241	241

1

Includes current portion.

B. Fair Value of Financial Instruments

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

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

I. Level Determinations and Classifications

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

a. Level I

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

b. Level II

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

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers in Level II. Level II fair values also include fair values determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

c. Level III

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

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

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

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

		Fair value[1]			
As at Dec. 31, 2008	**Level I**	**Level II**	**Level III**	**Total**	**Total carrying value**
Financial assets and liabilities measured at fair value					
Net risk management liabilities (assets)[2]	**$ (1)**	**$ (170)**	**$**	**$ (171)**	**$ (171)**
Financial assets and liabilities measured at other than fair value					
Long-term debt[3]	**$**	**$ 2,099**	**$**	**$ 2,099**	**$ 2,365**

		Fair value[1]			
As at Dec. 31, 2007	**Level I**	**Level II**	**Level III**	**Total**	**Total carrying value**
Financial assets and liabilities measured at fair value					
Net risk management liabilities (assets)[2]	$ (1)	$ 95	$	$ 94	$ 94
Financial assets and liabilities measured at other than fair value					

Long-term debt[3]	$	$ 1,874	$	$ 1,874	$ 1,837

1 *Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, short-term debt, and accounts payable and accrued liabilities).*

2 *Includes Energy Trading and Other Risk Management Assets and Liabilities on a net basis (Note 9).*

3 *Fair values have been determined using valuation techniques based on market inputs that are directly observable (Level II).*

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

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

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined would not result in materially different fair values.

The total amount of the change in fair value estimated using a valuation technique with unobservable inputs, for financial assets and liabilities measured and recorded at fair value, that was recognized in pre-tax earnings for the year ended Dec. 31, 2008 was a $16 million gain.
A reconciliation of the movements in Risk Management fair values by Level, as well as additional Level III gain (loss) information can be found in Note 9.

C. Inception Gains and Losses

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

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or based on a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the balance sheet in Energy Trading Risk Management Assets or Liabilities, and is recognized in earnings over the term of the related contracts. The difference yet to be recognized in net earnings and a reconciliation of changes during the period is as follows:

As at Dec. 31	**2008**	**2007**
Unamortized gain at beginning of period	**$ 3**	$ 4
New transactions	**1**	4
Recognized in the statement of earnings during the period:		
Amortization	**(2)**	(5)
Unamortized gain at end of period	**$ 2**	$ 3

D. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with expected NPNS contracts that are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

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

i. Commodity Price Risk Proprietary Trading

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

In compliance with the Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board of Directors approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net income in the period that the price changes occur. VaR at Dec. 31, 2008 associated with the Corporation's proprietary trading activities was $6 million.

ii. Commodity Price Risk Generation

The Generation segment utilizes various commodity contracts to manage the commodity price risk associated with its electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Plan is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios, and approval of asset transactions that could add potential volatility to the Corporation's reported earnings.

In addition, certain electricity sale contracts do not qualify as NPNS contracts. These contracts are designated as all-in-one hedges and are therefore accounted for as cash flow hedges. However, unlike a typical financial derivative used in a hedging relationship which results in a net settlement with the counterparty, settlement of these electricity contracts will not likely result in a net cash outflow to or an adverse earnings impact to the Corporation, despite their fair value usually resulting in a liability and a related AOCI cash flow loss on the Corporation's balance sheet. For contracts settled by physical delivery, the Corporation will physically deliver the electricity at the price fixed under the contract, and receive cash payment for that physical delivery. Any related cash flow hedge after-tax losses will be offset by the notional fair value of the contract. If the all-in-one hedge contracts cannot be settled by physical delivery of the underlying commodity they will be settled financially.

Changes in market prices associated with cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through OCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2008 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $86 million.

The Corporation's policy on asset-backed transactions is to seek NPNS contract status or hedge accounting treatment. Where this is not possible, the transactions are marked to the market value. These include, for example, positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions such as buybacks entered into to offset existing hedge positions. Changes in market prices associated with these transactions affect net earnings in the period in which the price change occurs. VaR at Dec. 31, 2008 associated with the Corporation's commodity derivative instruments used in the generation business, but which are not designated as hedges, was nil.

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity revenues received from Power Purchase Arrangements ("PPAs"). Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on pre-tax earnings and OCI for the year ended Dec. 31, 2008, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading interest rate and other hedging derivatives outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is the most reasonably possible change in market interest rates over the next quarter and is consistent with a +/- one standard deviation move from the mean.

		Pre-tax earnings increase[1]		OCI gain[1]
50 basis point change	$	3	$	

1

This calculation assumes a decrease in market interest rates. An increase would have the opposite effect. Amounts presented are pre-tax.

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, the U.S. and Australian dollars, as a result of investments and operations in foreign jurisdictions, the earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

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

The possible effect on pre-tax earnings and OCI for the year ended Dec. 31, 2008, due to changes in the exchange rates associated with financial instruments outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is the most reasonably possible change and is consistent with a +/- one standard deviation move from the mean.

Currency		**Pre-tax earnings decrease[1]**		**OCI gain[1]**
Euro	$		$	4
U.S.		5		3
AUD		2		
Total	**$**	**7**	**$**	**7**

1

These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect. Amounts presented are pre-tax.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages 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. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Generation PPAs as receivables are substantially all secured by letters of credit.

At Dec. 31 2008, TransAlta had two counterparties whose net settlement position each accounted for greater than 10 per cent of the total trade receivables outstanding at year-end.

The Corporation's maximum exposure to credit risk at Dec. 31, 2008, without taking into account collateral held, is represented by the current carrying amounts of accounts receivables and risk management assets as per the consolidated balance sheets. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading positions, at Dec. 31, 2008 was $105 million (2007 $6 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets that are neither past due nor impaired:

	Investment grade %	**Non-investment grade %**	**Total %**
Accounts receivable	86	14	100
Risk management assets	99	1	100

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the period is presented in Note 8.

At Dec. 31, 2008, the Corporation did not have any significant past due amounts, except as disclosed in Note 31.

III. Liquidity Risk

Liquidity risk is the risk that the Corporation may encounter difficulties in meeting obligations associated with financial liabilities and commitments related to collateral requirements under various contracts.

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

	2009	2010	2011	2012	2013	2014 and thereafter	Total
Short-term debt	$ 443	$	$	$	$	$	$ 443
Accounts payable and accrued liabilities	682						682
Long-term debt[1]	244	32	254	397	396	1,033	2,356
Energy Trading risk management (assets) liabilities[2]	(33)	(18)	(55)	(59)	1		(164)
Other risk management (assets) liabilities[3]	(19)		(12)			24	(7)
Interest on short- and long-term debt	172	145	133	112	98	564	1,224
Total	**$ 1,489**	**$ 159**	**$ 320**	**$ 450**	**$ 495**	**$ 1,621**	**$ 4,534**

1 *Excludes impact of derivatives.*

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

3 *Other risk management assets and liabilities are comprised of net risk management assets and liabilities, where the net result is an asset.*

E. Financial Instruments Provided as Collateral

At Dec. 31, 2008, $63 million (2007 $57 million) of financial assets, consisting of bank accounts and accounts receivable, related to the Corporation's proportionate share of CE Gen have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

F. Financial Assets Held as Collateral

At Dec. 31, 2008, the Corporation held U.S.$20 million in cash as collateral associated with counterparty obligations. Under the terms of the contract, the Corporation is obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations.

G. Gains and Losses on Financial Instruments

The Corporation's COD segment utilizes a variety of derivatives in its proprietary trading activities, and the related assets and liabilities are classified as held for trading. As outlined in Note 1(D), the net realized and unrealized gains are reported as revenue. For the year ended Dec. 31, 2008, the COD segment recognized $105 million (2007 $55 million) of net realized and unrealized gains and losses *(Note 32)*.

Net interest expense as reported on the consolidated statements of earnings includes interest income and expense, respectively, on the Corporation's interest-bearing financial assets, primarily cash and restricted cash, and its interest-bearing financial liabilities, primarily short- and long-term debt. Interest expense is calculated using the effective interest rate method *(Note 21)*. Interest rate derivatives that are not designated as hedges are classified as held for trading with the net gain or loss also recorded in net interest expense.

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

Other derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss recorded in OM&A expense.

The table below outlines the net gains (losses) included in earnings for the current and prior comparative periods:

Year ended Dec. 31	**2008**	2007
Interest rate derivatives gains	**$ 3**	$ 2
Foreign exchange derivatives (losses) gains	**(15)**	4
Other derivatives gains	**1**	

8. Accounts Receivable

As at Dec. 31	**2008**	**2007**
Gross accounts receivable	**$ 599**	$ 592
Allowance for doubtful accounts *(Note 31)*	**(57)**	(46)
Net accounts receivable	**$ 542**	$ 546

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2007	$ 46
Change in foreign exchange rates	11
Balance, Dec. 31, 2008	$ 57

9. Risk Management Assets and Liabilities

Risk management assets and liabilities are comprised of two major types: (1) those that are used in the COD and Generation segments in relation to trading activities and certain contracting activities ("Energy Trading") and (2) those used in hedging non-Energy Trading transactions, such as debt, and the net investment in self-sustaining foreign subsidiaries ("Other Risk Management Assets and Liabilities").

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

As at Dec. 31			**2008**			**2007**
Balance Sheet Totals	**Energy Trading**	**Other**	**Total**	**Energy Trading**	**Other**	**Total**
Risk management assets						
Current	**$ 176**	**$ 24**	**$ 200**	$ 34	$ 59	$ 93
Long-term	**187**	**34**	**221**	(4)	126	122
Risk management liabilities						
Current	**(142)**	**(6)**	**(148)**	(87)	(18)	(105)
Long-term	**(57)**	**(45)**	**(102)**	(192)	(12)	(204)
Net risk management assets (liabilities) outstanding	**$ 164**	**$ 7**	**$ 171**	$ (249)	$ 155	$ (94)

Energy Trading

The values of risk management assets and liabilities for Energy Trading are included on the consolidated balance sheets as follows:

As at Dec. 31			**2008**	**2007**
Balance Sheet Energy Trading	**Hedges**	**Non-hedges**	**Total**	**Total related to Energy Trading**
Risk management assets				
Current	**$ 99**	**$ 77**	**$ 176**	$ 34
Long-term	**186**	**1**	**187**	(4)
Risk management liabilities				
Current	**(71)**	**(71)**	**(142)**	(87)
Long-term	**(51)**	**(6)**	**(57)**	(192)
Net risk management assets (liabilities) outstanding	**$ 163**	**$ 1**	**$ 164**	$ (249)

The following table illustrates the disclosure on 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 year ended Dec. 31, 2008:

	Hedges			**Non-hedges**			**Total**		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management (liabilities) assets outstanding at Dec. 31, 2007[1]	$	$ (261)	$	$ 1	$ 11	$	$ 1	$ (250)	$
Changes in net asset value attributable to:									
Market changes		261			5	13		266	13
New contracts entered during the period		128		1	(5)	3	1	123	3
Contracts settled during the period		67		(1)	(11)	(16)	(1)	56	(16)
Change in foreign exchange rates		(32)						(32)	
Transfers in and/or out of Level III									
Net risk management assets outstanding at Dec. 31, 2008	**$**	**$ 163**	**$**	**$ 1**	**$**	**$**	**$ 1**	**$ 163**	**$**
Additional Level III gain (loss) information:									
Total change in fair value included in OCI			$			$			$
Total change in fair value included in pre-tax earnings			$			$			$

Total change in fair value included in pre-tax earnings relating to those net assets held at Dec. 31, 2008	$	$ 16	$ 16

1

Consistent with practices developed over 2008, the Corporation has reclassified over-the-counter derivatives with values based upon observable commodity futures curves, and derivatives with inputs validated by broker quotes in Level II.

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 COD and the Generation business segments.

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

		2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	Level I	$	$	$	$	$	$	$
	Level II	32	18	55	59	(1)		163
	Level III							
Non-hedges	Level I	$ 1	$	$	$	$	$	$ 1
	Level II							
	Level III							
Total	Level I	$ 1	$	$	$	$	$	$ 1
	Level II	32	18	55	59	(1)		163
	Level III							
Total assets (liabilities)		**$ 33**	**$ 18**	**$ 55**	**$ 59**	**$ (1)**	**$**	**$ 164**

The Corporation's fixed price proprietary trading positions at Dec. 31, 2008 and Dec. 31, 2007, were as follows:

Units (000s)	Electricity (MWh)	Natural gas (GJ)	Transmission (MWh)	Coal (tonnes)	Emissions (tonnes)
Fixed price payor, notional amounts, Dec. 31, 2008	**18,569**	**57,718**	**1,489**	**401**	
Fixed price payor, notional amounts, Dec. 31, 2007	16,189	54,523	1,854	1,644	6
Fixed price receiver, notional amounts, Dec. 31, 2008	**18,500**	**57,507**		**401**	
Fixed price receiver, notional amounts, Dec. 31, 2007	16,009	61,977		1,644	15
Maximum term in months, Dec. 31, 2008	**60**	**12**	**12**	**12**	
Maximum term in months, Dec. 31, 2007	24	12	6	23	2

Other Risk Management Assets and Liabilities

The values of non-Energy Trading risk management assets and liabilities included on the consolidated balance sheets are as follows:

As at Dec. 31			2008	2007
Balance Sheet Other	Hedges	Non-hedges	Total	Total related to non-Energy Trading
Risk management assets				
Current	**$ 22**	**$ 2**	**$ 24**	$ 59
Long-term	**34**		**34**	126
Risk management liabilities				
Current	**(3)**	**(3)**	**(6)**	(18)
Long-term	**(45)**		**(45)**	(12)
Net risk management assets (liabilities) outstanding	**$ 8**	**$ (1)**	**$ 7**	$ 155

The following table illustrates the disclosure on the movements in the fair value of the Corporation's other net risk management assets and liabilities separately by source of valuation during the year ended Dec. 31, 2008:

	Hedges[1]	Non-hedges[1]	Total
Net risk management assets (liabilities) outstanding at Dec. 31, 2007	$ 168	$ (13)	$ 155
Changes in net asset value attributable to:			
Market changes	9	14	23
New contracts entered during the period	(8)	(2)	(10)
Contracts settled during the period	(161)		(161)
Net risk management assets (liabilities) outstanding at Dec. 31, 2008	**$ 8**	**$ (1)**	**$ 7**

1 *Consistent with industry practices, all Other Risk Management Assets and Liabilities are classified in Level II.*

Changes in net risk management assets and liabilities for hedge positions are reflected within net earnings 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 or reduction in the net investment.

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

	2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	$ 20	$	$ 12	$	$	$ (24)	$ 8
Non-hedges	(1)						(1)
Total assets (liabilities)	**$ 19**	**$**	**$ 12**	**$**	**$**	**$ (24)**	**$ 7**

Details of notional information related to the hedges and non-hedges of other risk management assets are outlined below:

A. Hedges

I. Hedges of Foreign Operations

The Corporation has hedged a portion of its net investment in self-sustaining subsidiaries with cross-currency and foreign currency forward sales contracts as shown below:

a. Cross-Currency Swaps

Details of the notional amounts of cross-currency interest rate swaps are as follows:

As at Dec. 31					2008					2007
		Notional amount		Fair value	Maturities		Notional amount		Fair value	Maturities
Australian dollars	**AUD$**	**34**	**$**	**2**	**2009**	AUD$	34	$	1	2009
U.S. dollars	**U.S.$**		**$**			U.S.$	533	$	106	2009-2014

b. Foreign Sales Contracts

Details of the foreign currency forward sales contracts are as shown below:

As at Dec. 31					2008					2007
		Notional amount		Fair value	Maturities		Notional amount		Fair value	Maturities
U.S. dollars	**U.S.$**	**(107)**	**$**	**(1)**	**2009**	U.S.$	473	$	52	2008
Australian dollars	**AUD$**	**108**	**$**	**(1)**	**2009**	AUD$	82	$	1	2008

II. Hedges of Future Foreign Currency Obligations

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

As at Dec. 31				2008					2007
Currency sold	**Amount sold**	**Currency purchased**	**Amount purchased**	**Fair value asset**	**Maturities**	**Amount sold**	**Amount purchased**	**Fair value liability**	**Maturities**
Canadian dollars	**$ 51**	**U.S.$**	**U.S.$48**	**$ 8**	**2009-2010**	$ 96	U.S.$87	$ (11)	2008-2010
Australian dollars		**CDN$**				$ 6	$5		2008
Australian dollars		**U.S.$**				$ 2	$2		2008
U.S. dollars		**GBP**				$ 2	GBP1		2008
Canadian dollars	**$ 84**	**Euro**	**EUR57**	**$ 13**	**2009**	$ 69	EUR46	$ (3)	2008

III. Interest Rate Risk Management

The Corporation has converted fixed interest rate debt with rates ranging from 6.65 per cent to 6.9 per cent to floating rates through receive fixed/pay floating interest rate swaps as shown below:

As at Dec. 31		2008			2007	
	Notional amount	**Fair value**	**Maturities**	**Notional amount**	**Fair value**	**Maturities**
Fixed rate debt	**$ 100**	**$ 12**	**2011**	$ 200	$ 11	2011
	U.S.$ 100	**$ 21**	**2018**	U.S.$ 100	$ 2	2013

The Corporation has a forward start pay fixed swap outstanding at fixed rates ranging from 3.3 per cent to 4.2 per cent, as shown below:

As at Dec. 31		2008			2007	
	Notional amount	**Fair value**	**Maturity**	**Notional amount**	**Fair value**	**Maturity**
Floating rate debt	**U.S.$ 300**	**$ (46)**	**2019**	U.S.$ 200	$ 9	2018

Including the interest rate swaps above, 24 per cent of the Corporation's debt is subject to floating interest rates (2007 38 per cent).

At Dec. 31, 2008, a $33 million asset (2007 $13 million) related to the fair value of the interest rate swaps was recorded in long-term risk management assets.

B. Non-Hedges

I. Cross-Currency Swaps

The Corporation has an intercompany loan between its Australian and Barbados companies. Cross-currency interest rate swaps have been entered into in order to limit the Corporation's exposure to fluctuations in market interest rates. Details of the notional amounts of cross-currency interest rate swaps are as follows:

As at Dec. 31				2008				2007
		Notional amount	**Fair value**	**Maturity**		**Notional amount**	**Fair value**	**Maturity**
Australian dollars	**AUD$**	**41**	**$ 1**	**2009**	AUD$	80	$ (13)	2009

II. Held for Trading and Total Return Swaps

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

The Corporation also has employee compensation and deferred share units programs under which share grants or cash awards whose value depends on the share price are provided to certain employees and directors of the Corporation. To lower its cost of compensation, the Corporation has locked in the Dec. 31, 2008 settlement cost using a total return swap.

Details on the notional amounts of held for trading and total return swaps are as follows:

As at Dec. 31				2008				2007
		Notional amount	**Fair value**	**Maturities**		**Notional amount**	**Fair value**	**Maturities**
U.S. dollars	**U.S.$**	**90**	**$ (2)**	**2009**	U.S.$	15	$	2008

10. 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 and the Corporation chooses to seek hedge accounting treatment, 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.

A. 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.

No ineffective portion of fair value hedges was recorded in 2008, 2007, or 2006.

B. 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 year ended Dec. 31, 2008, a pre-tax unrealized gain of $327 million (2007 loss of $57 million, 2006 nil) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $91 million (2007 $25 million, 2006 nil) related to amounts previously related to OCI was reclassified to net earnings. For the year ended Dec. 31, 2008, a realized loss of nil (2007 nil, 2006 nil), was recognized in earnings for the ineffective portion.

Over the next 12 months, the Corporation estimates that $17 million (2007 $44 million) of after-tax losses will be reclassified from AOCI to net earnings. 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. In addition, it is the Corporation's intent to settle a substantial portion of the cash flow hedges by physical delivery of the underlying commodity, resulting in gross settlement at the contract price. These contracts are designated as all-in-one hedges and are required to be accounted for as cash flow hedges. However, unlike a typical financial derivative used in a hedging relationship, which results in a net settlement with the counterparty, these contracts will not likely result in a net cash outflow to the Corporation, despite their fair value usually resulting in a liability and a related AOCI loss on the Corporation's balance sheet. For contracts settled by physical delivery, the Corporation will physically deliver the electricity at the price fixed under the contract, and receive cash payment for that physical delivery. Any related cash flow hedge after-tax losses will be offset by the notional fair value of the contract. If the all-in-one hedge contracts cannot be settled by physical delivery of the underlying commodity they will be settled financially.

C. Net Investment Hedges

Foreign exchange contracts and foreign currency denominated liabilities are used to manage the Corporation's 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 year ended Dec. 31, 2008, the net after-tax gain of $47 million (2007 gain of $19 million), relating to the net investment in foreign operations, net of hedging, 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.

As at Dec. 31					**2008**	**2007**
	Fair value hedges	**Cash flow hedges**	**Net investment hedges**	**Not designated in a hedging relationship**	**Total**	**Total**
Financial assets						
Derivative instruments	**$ 33**	**$ 306**	**$ 2**	**$ 80**	**$ 421**	$ 215
Financial liabilities						
Derivative instruments	**$ (46)**	**$ (122)**	**$ (2)**	**$ (80)**	**$ (250)**	$ (309)

U.S. dollar denominated long-term debt with a face value of U.S.$1,100 million (2007 U.S.$600 million), and U.S. dollar denominated short-term debt with a face value of U.S.$238 million (2007 nil) has been designated as a part of the hedge of TransAlta's self-sustaining foreign operations.

11. Inventory

Inventory primarily represents coal and natural gas fuels that are valued at the lower of cost and net realizable value. The classifications are as follows:

As at Dec. 31	**2008**	**2007**

Coal	**$ 45**	$ 23
Natural gas	**5**	7
Purchased emission credits	**1**	
Total	**$ 51**	$ 30

The increase in coal inventory in 2008 compared to 2007 is primarily due to lower production at the Alberta Thermal plant and increased costs at the Alberta Thermal and Centralia Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2007	$ 30
Net additions	12
Change in foreign exchange rates	9
Balance, Dec. 31, 2008	**$ 51**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2008 and Dec. 31, 2007, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into earnings.

12. Restricted Cash

Restricted cash is comprised of debt service funds that are legally restricted, and require the maintenance of specific minimum balances equal to the next debt service payment, and amounts restricted for capital and maintenance expenditures.

The change in restricted cash is outlined below:

Balance, Dec. 31, 2007	$	242
Amount returned to TransAlta		(248)
Change in foreign exchange rates		6
Balance, Dec. 31, 2008	$	

During 2008, a subsidiary closed its position under a credit derivative agreement. The investment in notes held in trust as security for the subsidiary's obligation of $245 million under this agreement was returned to the subsidiary.

13. Investments

Investments previously represented TransAlta's investment in the Corporation's wholly owned Mexican operations.

On Oct. 8, 2008, the Corporation completed the sale of the Mexican operations to InterGen for $334 million. The Corporation recorded a charge to 2008 earnings of $62 million, net of tax, to reflect the difference between the net carrying value and anticipated net sale price of these assets. The gross charge of $97 million is recorded in equity loss and $35 million of tax recovery is recorded in income tax expense *(Note 27).*

14. Long-Term Receivables

In 2008, the Corporation received a notice of reassessment from the federal taxation authority relating to the disposal of the transmission business in the 2002 taxation year *(Note 6)*. The Corporation is in the process of challenging this reassessment. Since it is anticipated that the dispute will not be resolved within one year, any prepayment transfers and cash paid are recorded as a long-term receivable.

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

15. Property, Plant, and Equipment ("PP&E ")

As at Dec. 31				**2008**			**2007**
	Depreciation rates	**Cost**	**Accumulated depreciation and amortization**	**Net book value**	**Cost**	**Accumulated depreciation and amortization**	**Net book value**
Thermal generation equipment	**2%-67%**	**$ 4,835**	**$ 1,993**	**$ 2,842**	$ 4,338	$ 1,752	$ 2,586
Mining property & equipment	**2%-50%**	**763**	**352**	**411**	617	330	287
Gas generation	**3%-33%**	**2,244**	**1,030**	**1,214**	2,157	944	1,213
Geothermal generation	**3%-33%**	**386**	**87**	**299**	288	42	246
Hydro generation	**1%-50%**	**399**	**226**	**173**	385	215	170
Wind generation	**3%-5%**	**375**	**39**	**336**	209	33	176
Capital spares and other	**2%-50%**	**228**	**68**	**160**	186	62	124
Assets under construction		**443**		**443**	181		181
Coal rights [1]		**134**	**83**	**51**	133	80	53

Land		**63**		**63**	52		52
Transmission systems	**3%-4%**	**49**	**20**	**29**	47	18	29
Total		**$ 9,919**	**$ 3,898**	**$ 6,021**	$ 8,593	$ 3,476	$ 5,117

1

Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserve.

The Corporation capitalized $21 million of interest to PP&E in 2008 (2007 $6 million, 2006 nil).

An increase in foreign exchange rates from 2007 to 2008 has resulted in a $280 million increase in net book value of property, plant, and equipment. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings; rather any cumulative translation gain is reflected in AOCI.

16. Assets Held for Sale

During 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million; the remainder of the mining and reclamation equipment was reclassified to property, plant, and equipment as it is being retained for reclamation activities. This reclassification did not, and is not anticipated to, have a material impact on depreciation expense.

17. Goodwill

The change in goodwill is outlined below:

Balance, Dec. 31, 2007	$ 125
Change in foreign exchange rates	17
Balance, Dec. 31, 2008	**$ 142**

A portion of goodwill is related to CE Gen and is therefore denominated in U.S. dollars. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation gain is reflected in AOCI.

18. Intangible Assets

The change in intangible assets is outlined below:

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2007	$ 401	$ 192	$ 209
Change in foreign exchange rates	98	53	45
Amortization		41	(41)
Balance, Dec. 31, 2008	**$ 499**	**$ 286**	**$ 213**

The majority of intangible assets are related to CE Gen and are therefore denominated in U.S. dollars. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation gain is reflected in AOCI.

19. Other Assets

As at Dec. 31	2008	2007
Deferred license fees	**$ 21**	$ 22
Deferred contract costs	**8**	14
Deferred project development costs	**9**	15
Other	**5**	10
Other assets	**$ 43**	$ 61

Deferred license fees consist primarily of an Australian license for a lease on the land on which the power station assets are located, which is being amortized on a straight-line basis over the useful life of the power station assets to which the license relates.

Deferred contract costs consist of prepayments related to long-term contracts, which are being amortized on a straight-line basis over the term of the related contracts.

20. Short-Term Debt

As at Dec. 31	2008		2007	
	Outstanding	Interest[1]	Outstanding	Interest[1]
Commercial paper	$		$ 204	4.9%
Bank debt[2]	**443**	**2.8%**	447	5.2%
Total short-term debt	**$ 443**		$ 651	

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

2 *Bank debt is in the form of Bankers' Acceptances and other commercial borrowings.*

The short-term debt instruments are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million other commercial borrowings.

The $1.5 billion committed syndicated bank facility is dated July 2003 and is the primary source for short-term liquidity. The facility is a five-year revolver and was last renewed in May 2007, extending the maturity date to 2012. The syndicated credit facility is governed by reasonable commercial terms and bears interest at a floating rate currently of 2.27%.

The U.S.$300 million other commercial borrowings are a five-year facility, which bears interest at a floating rate currently of 3.46%.

21. Long-Term Debt and Net Interest Expense

A. Amounts Outstanding

As at Dec. 31		**2008**			**2007**	
	Carrying value	**Cost**	**Interest[1]**	**Carrying value**	**Cost**	**Interest[1]**
Debentures, due 2009 to 2033	**$ 682**	**$ 681**	**6.8%**	$ 950	$ 946	6.5%
Senior notes, (2008 U.S.$1,100 million, 2007 U.S.$600 million)	**1,352**	**1,344**	**6.3%**	573	586	6.3%
Non-recourse	**265**	**265**	**7.4%**	241	242	7.4%
Notes payable Windsor plant	**37**	**37**	**7.4%**	43	43	7.4%
Commercial loan obligation	**29**	**29**	**5.9%**	30	30	5.9%
	2,365	**2,356**		1,837	1,847	
Less: current portion	**(244)**	**(244)**		(154)	(154)	
Total long-term debt	**$ 2,121**	**$ 2,112**		$ 1,683	$ 1,693	

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

Fixed rate components of debentures and senior notes are hedged and therefore recorded at fair value. Non-recourse debt is not hedged and therefore recorded at cost.

Debentures bear interest at fixed rates ranging from 6.6 per cent to 7.3 per cent. The Corporation has converted $100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of receive fixed/pay floating interest rate swaps *(Note 9)*. These interest rate swaps mature in 2011. Debentures in the amount of $265 million matured in 2008.

In 2008, $100 million of debentures were redeemed by the holder of the debentures at a price of $98.45 per $100 of notional. The debentures had been issued at a fixed interest rate of 5.49 per cent, maturing in 2023 and redeemable at the option of the holder in 2008. In 2008, $50 million of debentures were redeemed at a negotiated price. The debentures were originally issued at a fixed interest rate of 5.66 per cent and were to mature in 2033.

Senior Notes U.S.$300 million of the senior notes bear an interest rate of 5.8 per cent and mature in 2013 and another U.S.$300 million bear an interest rate of 6.8 per cent and mature in 2012. The remaining U.S. $500 million of the U.S. $1,100 million senior notes bear an interest rate of 6.7 per cent and mature in 2018. In addition, the Corporation converted U.S.$100 million fixed interest rate debt with a rate of 6.7 per cent to floating rates through the use of receive fixed/pay floating interest rate swaps. These interest rate swaps mature in 2018. All senior notes have been designated as a hedge of the Corporation's net investment of U.S. operations. In 2008, the Corporation issued senior notes in the amount of U.S.$500 million. The senior notes bear interest at a rate of 6.65 per cent and mature in 2018.

Non-Recourse Debt consists of project financing debt, debt securities and senior secured bonds of CE Gen and debt related to the Wailuku River Hydroelectric L.P ("Wailuku") acquisition. The CE Gen related assets have been pledged as security for the project financing debt. The CE Gen debt securities are non-recourse, have maturity dates ranging from 2010 to 2018 and interest rates ranging from 7.5 per cent to 8.3 per cent. This debt is recorded at cost; the fair value as at Dec. 31, 2008 was $248 million (2007 $257 million). The outstanding balance of the non-recourse senior secured bonds as of Dec. 31, 2008 was $149 million (2007 $133 million), bear interest at 7.4 per cent, and are due in 2018. Wailuku debt at Dec. 31, 2008 has a cost of U.S.$9 million (2007 U.S.$9 million) and bears interest at a floating rate currently of 1.2 per cent.

Notes Payable Windsor Plant notes bear interest at fixed rates and are recourse to the Corporation through a standby letter of credit. These mature in November 2030.

Commercial Loan Obligation bears an interest rate of 5.9 per cent and will mature in 2023. This is an unsecured loan and requires annual payments of interest and principal.

B. Principal Repayments

2009	$ 244
2010	32
2011	254
2012	397
2013	396
2014 and thereafter	1,033
Total[1]	**$ 2,356**

1 *Excludes impact of derivatives.*

C. Interest Expense

Year ended Dec. 31	**2008**	2007	2006
Interest on long-term debt	**$ 147**	$ 145	$ 154
Interest on short-term debt	**30**	26	13
Interest on preferred securities			14
Interest income	**(46)**	(32)	(13)
Capitalized interest	**(21)**	(6)	

Net interest expense	**$ 110**	$ 133	$ 168

The Corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2008 relates to Keephills 3, Kent Hills, Summerview, and Blue Trail. In 2007 the capitalized interest related to the Corporation's investment in Keephills 3 and Kent Hills.

In the current year, an appeal was resolved pertaining to the timing of revenue recognition and deductions on previous years' tax returns based on applicable income tax laws. Consequently, $30 million of refund interest received and due from taxation authorities was recorded as interest income.

D. Guarantees

I. Letters of Credit

Letters of credit are issued to counterparties that have credit exposure to certain subsidiaries. If the Corporation or its subsidiary does not pay amounts due under the contract, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the consolidated balance sheets. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Dec. 31, 2008 totalled $430 million (2007 $550 million) with nil (2007 nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.2 billion of committed and uncommitted credit facilities of which $1.4 billion is not drawn and is available as of Dec. 31, 2008, subject to customary borrowing conditions.

TransAlta letters of credit do not contain recourse provisions nor does the Corporation hold any assets as collateral against the guarantees issued.

22. Asset Retirement Obligations

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

Balance, Dec. 31, 2006	$	329
Liabilities incurred in period		3
Liabilities settled in period		(38)
Accretion expense		24
Revisions in estimated cash flows		(19)
Change in foreign exchange rates		(23)
Balance, Dec. 31, 2007	$	276
Liabilities incurred in period		3
Liabilities settled in period		(37)
Accretion expense		22
Revisions in estimated cash flows		10
Change in foreign exchange rates		23
	$	297
Less current portion		(45)
Balance, Dec. 31, 2008	**$**	**252**

The Corporation 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 *(Note 14)*.

During 2008, the Corporation prepared a revised decommissioning cost estimate of the future asset retirement costs at certain facilities. As a result, the total expected costs have been increased by $10 million (2007 reduced by $19 million).

TransAlta estimates that the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $0.8 billion, which will be incurred between 2009 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent and an inflation rate of 2.3 per cent were used to calculate the carrying value of the asset retirement obligations. At Dec. 31, 2008, the Corporation had a surety bond in the amount of U.S.$192 million (2007 U.S.$192 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2008, the Corporation had letters of credit in the amount of $57 million (2007 $50 million) in support of future retirement obligations at the Alberta mines.

23. Deferred Credits and Other Long-Term Liabilities

As at Dec. 31		**2008**		**2007**
Deferred coal revenues *(Note 28)*	**$**	**31**	$	9
Sale of emission credits		**7**		9
Power purchase arrangement in limited partnership		**23**		25
Accrued benefit liability *(Note 34)*		**40**		48
Other		**21**		10
Total deferred credits and other long-term liabilities	**$**	**122**	$	101

The power purchase arrangement in the limited partnership represents the fair value adjustments for the Sheerness Generating Station to deliver power at less than the prevailing market price at the time of the acquisition of the plant by TransAlta Cogeneration, L.P. ("TA Cogen"). The power purchase arrangement is amortized on a straight-line basis over the life of the contract.

24. Common Shares

A. Issued and Outstanding

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

Year ended Dec. 31	**2008**		**2007**	
	Common shares (millions)	**Amount**	**Common shares (millions)**	**Amount**
Issued and outstanding, beginning of year	**200.9**	**$ 1,781**	202.4	$ 1,782
Stock options expired				(2)
Issued for cash under stock option plans	**0.4**	**8**	0.8	19
Issued under Performance Share Ownership Plan	**0.2**	**7**	0.1	3
Shares purchased under NCIB *(Note 25)*	**(3.9)**	**(35)**	(2.4)	(21)
Issued and outstanding, end of year	**197.6**	**$ 1,761**	200.9	$ 1,781

On Feb. 1, 2008, one million stock options were granted at an exercise price of $31.97, being the last sale price of board lots of the shares on the TSX the day prior to the day the options were granted for Canadian employees, and U.S.$31.83, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire on Feb. 1, 2019 *(Note 33)*.

At Dec. 31, 2008 the Corporation had 1.7 million outstanding employee stock options (2007 1.2 million). For the year ended Dec. 31, 2008, 0.3 million options with a weighted average exercise price of $20.52 were exercised resulting in 0.3 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $27.96.

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. The plan was last approved by shareholders on April 26, 2007.

When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a Permitted Bid, where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring person. Each right will entitle the shareholder to acquire an additional $200 worth of common shares for $100.

C. Dividend Reinvestment and Share Purchase ("DRASP") Plan

Under the terms of the DRASP plan, participants are able to purchase additional common shares by reinvesting dividends. Effective Jan. 1, 2007, the Corporation amended the DRASP plan, whereby after Dec. 31, 2006, the five per cent discount on the price of shares purchased through the DRASP plan and issued from treasury was suspended. After Dec. 31, 2006, shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the TSX on the investment dates.

D. Earnings Per Share ("EPS")

Year ended Dec. 31	**2008**	**2007**	**2006**
Net earnings	**$ 235**	$ 309	$ 45
Basic and diluted weighted average number of common shares outstanding	**199**	202	201
Earnings per share			
Basic	**$ 1.18**	$ 1.53	$ 0.22
Diluted	**$ 1.18**	$ 1.53	$ 0.22

The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding *(Note 33)*.

25. Shareholders ' Equity

A. Shareholder's Equity Reconciliation

	Common shares	**Retained earnings**	**Accumulated Other Comprehensive (Loss)/Income**	**Total shareholders' equity**
Balance, Dec. 31, 2007	$ 1,781	$ 763	$ (245)	$ 2,299
Net earnings for the year ended Dec. 31, 2008		235		235
Common shares issued (dividends declared)	15	(215)		(200)
Shares purchased under NCIB	(35)	(95)		(130)
Gains on translating financial statements of self-sustaining foreign operations, net of tax			47	47
Gains on derivatives designated as cash flow hedges, net of tax			198	198
Derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net earnings in the current period			69	69
			(8)	(8)

Loss on Mexico sale reclassified to statement of earnings *(Note 27)*								
Balance, Dec. 31, 2008	**$**	**1,761**	**$**	**688**	**$**	**61**	**$**	**2,510**

B. Components of AOCI

As at Dec. 31		**2008**		**2007**
Cumulative unrealized gains (losses) on translating financial statements of self-sustaining foreign operations, net of tax	**$**	**(7)**	$	(45)
Cumulative unrealized gains (losses) on cash flow hedges, net of tax		**68**		(200)
Accumulated Other Comprehensive Income (Loss)	**$**	**61**	$	(245)

C. Normal Course Issuer Bid ("NCIB") Program

On May 5, 2008, TransAlta announced plans to renew the NCIB program until May 5, 2009. The Corporation received the approval to purchase, for cancellation, up to 19.9 million of its common shares representing 10 per cent of the 199 million common shares issued and outstanding as at April 23, 2008. Any purchases undertaken will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2008, TransAlta purchased 3,886,400 (2007 2,371,800) shares at an average price of $33.46 (2007 $31.59) per share. The shares were purchased for an amount higher than their weighted average book value per share of $8.95 per share (2007 $8.92 per share) resulting in a reduction of retained earnings of $95 million (2007 $54 million).

As at Dec. 31	2008	2007
Total shares purchased	**3,886,400**	2,371,800
Average purchase price per share	**$ 33.46**	$ 31.59
Total cost	**$ 130**	$ 75
Weighted average book value of shares cancelled	**35**	21
Reduction to retained earnings	**$ 95**	$ 54

Given the current unprecedented level of volatility in the financial markets, TransAlta has decided to suspend purchases under its NCIB program at this time in order to maintain maximum financial flexibility. TransAlta will re-evaluate financial market conditions throughout 2009 to determine the best use of cash resources going forward.

26. Capital

TransAlta's components of capital are listed below:

As at Dec. 31	2008	2007	Increase/ (decrease)
Short-term debt including current portion of long-term debt	**$ 687**	$ 805	$ (118)
Less: cash and cash equivalents	**(50)**	(51)	1
	637	754	(117)
Long-term debt			
Recourse	**1,889**	1,474	415
Non-recourse	**232**	209	23
Non-controlling interests	**469**	496	(27)
Common shareholders' equity			
Common shares	**1,761**	1,781	(20)
Retained earnings	**688**	763	(75)
AOCI	**61**	(245)	306
	5,100	4,478	622
Total capital	**$ 5,737**	$ 5,232	$ 505

The long-term portion of recourse debt increased from Dec. 31, 2007 as a result of the issuance of senior notes in the amount of U.S.$500 million and changes in exchange rates. This increase in long-term debt was partially offset by scheduled payments.

TransAlta's strategy for managing capital remained unchanged from Dec. 31, 2007.

TransAlta's objectives in managing capital are to:

A. Maintain an Investment Grade Credit Rating:

The Corporation operates in a long-cycle and capital intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable rates. TransAlta monitors key capital ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and manages capital in line with those expectations:

Cash flow to interest Cash flow from operating activities before changes in working capital plus net interest expense divided by net interest expense excluding capitalized interest. TransAlta targets this ratio to be a minimum multiple of four.

Cash flow to total debt Cash flow from operating activities before changes in working capital divided by two-year average of total debt. TransAlta targets this ratio to be a minimum of 25 per cent.

Debt to invested capital Short-term debt and long-term debt less cash and cash equivalents divided by total debt, non-controlling interests, and common shareholders' equity less cash and cash equivalents. TransAlta targets this ratio to be less than 55 per cent.

These ratios are presented below:

Year ended Dec. 31	2008	2007
Cash flow to interest (times)	**7.2**	6.6
Cash flow to total debt (%)	**31.1**	30.7
Debt to invested capital (%)	**48.1**	46.8

The increase in cash flow to interest resulted from increased cash from operating activities and lower interest expense. The increase in cash flow to total debt resulted from an increase in cash flows from operating activities offsetting the increase in debt balances *(Notes 20 and 21)*. TransAlta routinely monitors forecasts for earnings, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Capital Assets:

These amounts are summarized in the table below:

Year ended Dec. 31	**2008**	2007	Increase/ (decrease)
Cash flow from operating activities	**$ 1,038**	$ 847	$ 191
Dividends paid	**(212)**	(205)	(7)
Capital asset expenditures	**(1,006)**	(599)	(407)
Net cash (outflow) inflow	**$ (180)**	$ 43	$ (223)

The decrease in the total net cash flows primarily resulted from higher capital expenditures on growth projects.

While any of the existing debentures are outstanding, the Corporation will not issue or in any other manner become liable for any indebtedness, unless the aggregate principal amount of the Corporation's indebtedness, as defined in the Corporation's trust indenture, does not exceed 75 per cent of total capital.

TransAlta's credit facilities are unsecured and provide funds in either Canadian or U.S. currencies. They contain standard terms and conditions including covenants with respect to financial leverage and cashflow coverage that would be considered typical of bank credit facilities of this nature.

TransAlta's formal dividend policy targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings. TransAlta's management defines comparable earnings as net earnings adjusted for items that are expected to be non-recurring in the future.

27. Acquisitions and Disposals

A. Acquisitions

On Feb. 17, 2006, the Corporation acquired a 50 per cent ownership in Wailuku for $1 million. The acquisition is accounted for using the purchase method of accounting. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The financial operations of Wailuku have been proportionately consolidated with those of TransAlta.

Net assets acquired at assigned values:

Working capital, including cash of $0.3 million	$ (3)
Property, plant, and equipment	26
Long-term debt, including current portion	(22)
Total	$ 1
Consideration:	
Cash	$ 1

This has been reported under "other" on the investing section of the cash flow statement.

B. Disposals

On Oct. 8, 2008, TransAlta successfully completed the sale of the Mexican business to InterGen for a sale price of $334 million *(Note 13)*. The sale included the plants at both facilities and all associated commercial arrangements.

The details of the sale are as follows:

Contractual proceeds			$	334
Less: closing costs				(3)
Net proceeds excluding cash on hand of $1 million				331
Book value of investment				420
Loss before deferred foreign exchange losses				89
Deferred foreign exchange losses on the net assets of the Mexican operations	$	147		
Deferred gains on financial instruments designated as hedges of the net assets of the Mexican operations		(148)		
Income tax expense on financial instruments		9		
Deferred foreign exchange losses				8
Loss before income taxes			$	97
Income tax recovery				35
Net loss			**$**	**62**

Included in the book value of the investment is a provision for representations and warranties of $13 million.

28. Related Party Transactions

On January 1, 2009, TAU and TransAlta Energy Corporation ("TEC") transferred certain generation and transmission assets to a newly formed internal partnership, TransAlta Generation Partnership ("TAGP"), before amalgamating with TransAlta Corporation.

On Dec.16, 2006, TAU, a wholly owned subsidiary, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership with EPCOR Power Development Corporation. TAU will supply coal until the earlier of the permanent closure of the Keephills 3 facility or from early termination of the agreement by TAU and the partners of the joint venture. As at Dec. 31, 2008, TAU had received $27 million from Keephills 3 Limited Partnership, a wholly owned subsidiary, for the right to coal. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011. Payments received prior to that date for the right to coal are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

In August 2006, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican Energy Holdings Company ("MidAmerican"), a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. As this available power is from plants that are already contracted, the value of this agreement is immaterial. 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, one of TransAlta's subsidiaries, TA Cogen, entered into various transportation swap transactions with 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 the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the 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 and therefore has no risk other than counterparty risk.

29. Contingencies

TransAlta is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. 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.

30. Commitments

A significant portion of the Corporation's electricity and thermal sales revenues are subject to PPAs and long-term contracts. Commencing Jan. 1, 2001, a large portion of Alberta's coal generating assets became subject to long-term PPAs for a period approximating the remaining life of each plant or unit. These PPAs set a production requirement and availability target for each plant or unit and the price at which each MWh will be supplied to the customer. Remaining coal capacity in Alberta is sold on the open electricity market.

A portion of Poplar Creek's electrical and all of its steam capacity is committed to the customer under a long-term contract. The remaining electrical capacity may be taken by the customer at specified rates or sold on the open electricity market by TransAlta. Other gas-fired facilities in Alberta supply steam and/or electricity to specified customers under long-term contracts with additional requirements for availability, reliability and other plant-specific performance measures.

Sarnia has 20-year contracts with a customer group with three five-year options for extensions to the contracts. The contracts allow for up to 40 per cent of the plant's maximum capacity. These contracts set payments for peak megawatts, total megawatt hours supplied to the customers and steam consumed, while TransAlta assumes the availability and heat rate risk. On Jan. 1, 2006, TransAlta signed a five-year agreement with the Ontario Power Authority to supply up to 500 megawatts ("MW") of electricity to the Ontario electricity market. The remaining capacity at Sarnia is available for export to the merchant market, based on market prices. Production at the remaining Ontario plants is subject to contracts expiring in five to 10 years.

Mississauga, Windsor-Essex, and Ottawa have contracts that set availability targets and the price at which the plant will be paid per MWh produced, as well as risk sharing of fuel costs based on market prices. Thermal energy contracts for Mississauga and Windsor expire at the same time as the energy production contracts and are with a different customer base. Ottawa has thermal contracts with three different customers. The contract with the main customer expires at the end of 2022. These contracts set payments for volumes consumed, while TA Cogen assumes the heat rate risk. On Oct. 12, 2007, the Corporation signed an agreement amending the original PPA with the Ontario Electricity Financial Corporation ("OEFC") for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant production following the expiry of long-term natural gas supply contracts. The agreement will be in effect from Nov. 1, 2007 until Dec. 31, 2012.

At Centralia Thermal, a significant portion of production is subject to short- to medium-term energy sales contracts.

Centralia Thermal has various coal supply and associated rail transport contracts to provide coal for use in production. During 2008, TransAlta entered into various coal supply agreements with three suppliers for the Centralia Thermal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates ranging from June 1, 2008 to Dec. 31, 2013. The obligation under these agreements is expected to be U.S.$157 million over the six-year period.

At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal. These amounts are included under coal supply and mining agreements.

During 2008, TransAlta entered into several five-year agreements with Bonneville Power Administration Transmission ("BPAT") to purchase 400 MW of Pacific Northwest transmission network capacity. Provided BPAT can meet certain conditions for delivering the service, the Corporation is committed to taking the services at BPAT's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed. The obligation under these agreements is expected to be U.S.$46 million for the five-year period.

On May 27, 2008, TransAlta announced a 66 MW expansion of its Summerview wind farm located in southern Alberta near Pincher Creek. The capital cost of the project is estimated at $123 million with construction commencing in the second quarter of 2009 and commercial operations expected to begin in the first quarter of 2010. As at Dec. 31, 2008, total capital spend on this project was $25 million.

On April 21, 2008, TransAlta announced a 53 MW efficiency uprate at TransAlta's Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009. As at Dec. 31, 2008, total capital spend on this project was $17 million.

On Feb. 13, 2008, TransAlta announced plans to design, build, and operate Blue Trail, a 66 MW wind power project in southern Alberta. The capital cost of the project is estimated at $115 million. Commercial operations are expected to commence in the fourth quarter of 2009. As at Dec. 31, 2008, total capital spend on this project was $26 million.

On June 21, 2007, TAU 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 $121 million for the purchase of the equipment, and an additional $29 million for the assembly and commissioning of the dragline, for a total of approximately $150 million, with final payments for goods and services due by May 2010. As at Dec. 31, 2008, total payments under this agreement were $79 million.

Keephills 3 plant construction and associated mine capital costs via the Keephills 3 Limited Partnership are anticipated to be approximately $1.7 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $840 million. As at Dec. 31, 2008, total spend on this project was $431 million.

On Dec. 31, 2008, commercial operations began at the wind power facility in New Brunswick ("Kent Hills"). TransAlta 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 million. Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

The Corporation has entered into a number of long-term gas purchase agreements, transportation and transmission agreements, royalty and right-of-way agreements in the normal course of operations.

Approximate future payments under the fixed price purchase contracts, operating leases, mining agreements, interest on long-term debt, and project commitments are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Interest on long-term debt1	Project commitments	Total
2009	$ 9	$ 17	$ 51	$ 158	$ 292	$ 527
2010	7	19	47	145	74	292
2011	7	19	47	133	4	210
2012	7	19	47	112		185
2013	8	18	51	98		175
2014 and thereafter	37	73	317	564		991
Total	**$ 75**	**$ 165**	**$ 560**	**$ 1,210**	**$ 370**	**$ 2,380**

1

Includes impact of derivatives.

31. 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"), the Federal Energy Regulatory Commission ("FERC") established a claim of approximately U.S.$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 U.S.$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 Aug. 24, 2007, the U.S. Court of Appeals for the Ninth Circuit granted the appeal. TransAlta has requested a rehearing, however; FERC has yet to make a ruling on such a request and such a decision is not expected in the near future.

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. The Ninth Circuit held that FERC's authorization of market-based rate tariffs in these proceedings complied with the FPA, but that FERC erred in refusing refunds on the grounds that it lacked authority to order refunds for violations of its reporting requirement and remanded the case for further refund proceedings. The court did not itself order any refunds, leaving it to FERC to consider appropriate remedial options.

On March 21, 2008, FERC issued an Order on Remand establishing a refund hearing before an Administrative Law Judge to determine whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable in California during the 2000-2001 period. The California parties appealed FERC's basis for determining refund liability but the appeal was denied by FERC on October 6, 2008.

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.

32. Segment Disclosures

A. Description of Reportable Segments

The Corporation has two reportable segments as described in Note 1.

Each business segment assumes responsibility for its operating results measured as operating income or loss.

Generation expenses include COD's intersegment charge for energy marketing and financial risk management services in the amount of $30 million (2007 $27 million, 2006 $28 million). COD's operating expenses are presented net of these intersegment charges.

The accounting policies of the segments are the same as those described in Note 1. Intersegment transactions are accounted for on a cost-recovery basis that approximates market rates.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2008	Generation	COD	Corporate	Total
Revenues	**$ 3,005**	**$ 105**	**$**	**$ 3,110**
Fuel and purchased power *(Notes 1 and 3)*	**(1,493)**			**(1,493)**
Gross margin	**1,512**	**105**		**1,617**
Operations, maintenance, and administration	**487**	**53**	**97**	**637**
Depreciation and amortization	**409**	**3**	**16**	**428**
Taxes, other than income taxes	**19**			**19**
Intersegment cost allocation	**30**	**(30)**		
Operating expenses	**945**	**26**	**113**	**1,084**
Operating income (loss)	**$ 567**	**$ 79**	**$ (113)**	**$ 533**
Foreign exchange loss				**(12)**
Gain on sale of equipment *(Note 16)*				**5**
Net interest expense *(Note 21)*				**(110)**
Equity loss *(Notes 13 and 27)*				**(97)**
Earnings before non-controlling interests and income taxes				**$ 319**

Year ended Dec. 31, 2007	Generation	COD	Corporate	Total
Revenues	$ 2,720	$ 55	$	$ 2,775
Fuel and purchased power *(Notes 1 and 3)*	(1,231)			(1,231)
Gross margin	1,489	55		1,544
Operations, maintenance, and administration	447	34	96	577
Depreciation and amortization	391	1	14	406
Taxes, other than income taxes	20			20
Intersegment cost allocation	27	(27)		
Operating expenses	885	8	110	1,003
Operating income (loss)	$ 604	$ 47	$ (110)	$ 541
Foreign exchange gain				3
Gain on sale of equipment *(Note 16)*				16
Net interest expense *(Note 21)*				(133)
Equity loss *(Note 13)*				(50)
Earnings before non-controlling interests and income taxes				$ 377

Year ended Dec. 31, 2006	Generation	COD	Corporate	Total
Revenues	$ 2,612	$ 65	$	$ 2,677
Fuel and purchased power *(Note 1)*	(1,186)			(1,186)
Gross margin	1,426	65		1,491
Operations, maintenance, and administration	458	37	86	581
Depreciation and amortization	397	1	12	410
Taxes, other than income taxes	21			21
Intersegment cost allocation	28	(28)		
Operating expenses	904	10	98	1,012
Mine closure charges *(Note 3)*	192			192
Asset impairment charges *(Note 4)*	130			130
Operating income (loss)	$ 200	$ 55	$ (98)	$ 157
Foreign exchange loss				(1)
Net interest expense *(Note 21)*				(168)
Equity loss *(Note 13)*				(17)
Loss before non-controlling interests and income taxes				$ (29)

II. Selected Balance Sheet Information

Dec. 31, 2008	Generation	COD	Corporate	Total
Goodwill *(Note 17)*	**$ 112**	**$ 30**	**$**	**$ 142**
Total segment assets	**$ 7,110**	**$ 206**	**$ 499**	**$ 7,815**

Dec. 31, 2007				
Goodwill *(Note 17)*	$ 95	$ 30	$	$ 125
Total segment assets	$ 5,950	$ 147	$ 1,060	$ 7,157

An increase in foreign exchange rates has resulted in a $17 million change in goodwill. A portion of goodwill is related to CE Gen and is therefore denominated in U.S. dollars. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation loss is reflected in AOCI.

III. Selected Cash Flow Information

Year ended Dec. 31, 2008	Generation	COD	Corporate	Total
Capital expenditures	**$ 992**	**$ 7**	**$ 7**	**$ 1,006**

Year ended Dec. 31, 2007				
Capital expenditures	$ 577	$ 5	$ 17	$ 599

Year ended Dec. 31, 2006				
Capital expenditures	$ 206	$ 2	$ 16	$ 224

IV. Depreciation and Amortization Expense Per Statements of Cash Flows

The reconciliation between depreciation expense on the statements of earnings and statements of cash flows is presented below:

Year ended Dec. 31	2008	2007	2006
Depreciation and amortization expense for reportable segments	**$ 428**	$ 406	$ 410
Depreciation included in fuel, and purchased power	**38**	30	50
Accretion expense, included in depreciation and amortization expense	**(22)**	(24)	(22)
Other	**7**	3	
Depreciation and amortization expense per statements of cash flows	**$ 451**	$ 415	$ 438

C. Geographic Information

I. Revenues

Year ended Dec. 31	2008	2007	2006
Canada	**$ 1,839**	$ 1,742	$ 1,761
U.S.	**1,165**	932	825
Australia	**106**	101	91
Total revenue	**$ 3,110**	$ 2,775	$ 2,677

II. Property, Plant, and Equipment and Goodwill

	Property, Plant, and Equipment *(Note 15)*		Goodwill *(Note 17)*	
As at Dec. 31	**2008**	**2007**	**2008**	**2007**
Canada	**$ 4,464**	$ 3,877	**$ 57**	$ 57
U.S.	**1,405**	1,087	**85**	68
Australia	**152**	153		
Total	**$ 6,021**	$ 5,117	**$ 142**	$ 125

33. Stock-Based Compensation Plans

At Dec. 31, 2008, the Corporation had three types of stock-based compensation plans and an employee share purchase plan.

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

A. Fixed Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. U.S. Plan

This plan mirrors the rules of the Canadian plan.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia, excluding directors and officers. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

Summary of the total options outstanding and options exercisable at Dec. 31, 2008 are shown below:

		Options outstanding			Options exercisable	
		Number outstanding at Dec. 31, 2008 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at Dec. 31, 2008 (millions)	Weighted average exercise price
Range of exercise prices						
$13.32	20.55	**0.5**	5.0	$ 16.11	**0.3**	$ 15.64
$20.56	27.80	**0.3**	2.2	24.41	**0.2**	24.41
$27.81	35.05	**0.7**	9.1	32.11		
$35.06	42.26	**0.1**	9.1	38.95		
$13.32	42.26	**1.6**	6.8	$ 27.06	**0.5**	$ 19.51

The change in the fixed option plans are outlined below:

Year ended Dec. 31	**2008**		**2007**		**2006**	
	Number of share options (millions)	**Weighted average exercise price**	**Number of share options (millions)**	**Weighted average exercise price**	**Number of share options (millions)**	**Weighted average exercise price**
Outstanding, beginning of year	**1.1**	**$ 19.42**	2.0	$ 19.95	2.7	$ 19.45
Granted	**1.0**	**32.10**				
Exercised	**(0.3)**	**20.52**	(0.7)	21.19	(0.6)	17.51
Cancelled or expired	**(0.2)**	**27.96**	(0.2)	17.52	(0.1)	20.65
Outstanding, end of year	**1.6**	**$ 27.06**	1.1	19.42	2.0	$ 19.95

B. Performance Stock Option Plan

In 1999, the Corporation expanded enrolment in the stock option program to include all Canadian employees of the Corporation, excluding the level of director and above, by issuing stock options with an expiry date of 2009 and vesting dependent upon achieving certain earnings per share targets.

The change in the performance stock option plan is outlined below:

Year ended Dec. 31	2008			2007			2006		
	Number of share options (millions)		Weighted average exercise price	Number of share options (millions)		Weighted average exercise price	Number of share options (millions)		Weighted average exercise price
Outstanding, beginning of year	**0.1**	**$**	**22.71**	0.2	$	22.73	0.2	$	22.62
Exercised			**22.92**	(0.1)		22.75			21.99
Cancelled or expired			**23.05**						23.05
Outstanding, end of year	**0.1**	**$**	**22.55**	0.1	$	22.71	0.2	$	22.73

No options were issued in 2008 (2007 nil, 2006 nil).

At Dec. 31, 2008, the Corporation had 3,000 options under this plan with an exercise price of $14.15 and a weighted average remaining contractual life of one year and 49,875 options with an exercise price of $23.05 and a weighted average remaining contractual life of 0.1 years outstanding. At Dec. 31, 2008, all outstanding options had vested.

C. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, which commenced in 1997, the Corporation was authorized to grant to employees and directors up to an aggregate of 2.0 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, could not exceed 6.0 million common shares. Participants in the PSOP receive grants which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the Corporation's common shares amongst the companies comprising the S&P/TSX Composite Index. Expense related to this plan is recorded during the period earned, with corresponding payable recorded in liabilities.

On Dec. 31, 2001, the plan was modified so that after three years, once the PSOP eligibility has been determined, 50 per cent of the shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. In addition, the number of common shares the Corporation is authorized to grant under the terms of the PSOP was increased to 4.0 million common shares and the maximum number of common shares that may be issued under both the PSOP and share option plans was increased to 13.0 million common shares.

Year ended Dec. 31	**2008**	**2007**	**2006**
Number of awards outstanding, beginning of year (in millions)	**1.0**	1.2	1.1
Granted	**0.2**	0.4	0.6
Awarded	**(0.2)**	(0.1)	(0.1)
Cancelled or expired	**(0.1)**	(0.5)	(0.4)
Number of awards outstanding, end of year	**0.9**	1.0	1.2

In 2008, PSOP compensation expense was $5 million after-tax (2007 $7 million after-tax, 2006 $4 million after-tax), which is included in OM&A expense in the statements of earnings. In 2008, 221,855 common shares were issued at $24.30 per share. In 2007, 103,896 common shares were issued at $33.35 per share. In 2006, 137,039 common shares were issued at $25.41 per share.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are no longer eligible for this program in accordance with the Sarbanes-Oxley legislation. The Corporation will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2008, accounts receivable from employees under the plan totalled $3 million (2007 $0.3 million).

E. Stock-Based Compensation

At Dec. 31, 2008, the Corporation had 1.7 million outstanding employee stock options (2007 1.2 million).

The Corporation uses the fair value method of accounting for awards granted under its fixed stock option plans and its performance stock option plan. On Feb. 1, 2008, 1.0 million stock options were granted at a strike price of $31.97, being the last sale price of board lots of the shares on the TSX the day prior to the day the options were granted for Canadian employees, and U.S.$31.83, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire after 10 years. The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model and the following assumptions, resulting in a fair value of $6.31 per option:

Risk-free interest rate (%)	3.6
Expected life of the options (years)	7
Dividend rate (%)	3.4
Volatility in the price of the corporation's shares (%)	23.2

The estimated fair value of these options granted in 2005 was determined using the binomial model and the following assumptions, resulting in a fair value of $6.84 per option:

Risk-free interest rate (%)	4.3
Expected life of the options (years)	10
Dividend rate (%)	5.6
Volatility in the price of the corporation's shares (%)	47.0

The estimated fair value of these options granted in 2002 and prior was determined using the binomial model and the following assumptions, resulting in a weighted average fair value of $4.25 per option:

Risk-free interest rate (%)	5.9
Expected hold period to exercise (years)	7
Volatility in the price of the corporation's shares (%)	28.3

34. Employee Future Benefits

A. Description

The Corporation has registered pension plans in Canada 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.

The latest actuarial valuations for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2008. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2008. The last actuarial valuation for funding purposes of the registered plan was Dec. 31, 2007, and the effective date of the next required valuation for funding purposes is Dec. 31, 2010. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $52 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2007. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2007.

B. Costs Recognized

Year ended Dec. 31, 2008	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 3**	**$ 1**	**$ 1**	**$ 5**
Interest cost	**20**	**3**	**1**	**24**
Actual return on plan assets	**55**			**55**
Actuarial gain	**(49)**	**(5)**	**(4)**	**(58)**
Difference between expected return and actual return on plan assets	**(79)**			**(79)**
Difference between amortized and actuarial loss on accrued benefit obligation for year	**50**	**6**	**5**	**61**
Past service costs		**2**		**2**
Difference between amortized and actual plan amendments of past service costs for the year		**(2)**		**(2)**
Amortization of net transition (asset) obligation	**(9)**			**(9)**
Defined benefit (income) expense	**(9)**	**5**	**3**	**(1)**
Defined contribution option expense of registered pension plan	**17**			**17**
Net expense	**$ 8**	**$ 5**	**$ 3**	**$ 16**

Year ended Dec. 31, 2007	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	$ 4	$ 2	$ 1	$ 7
Interest cost	19	2	2	23
Actual return on plan assets	(10)			(10)
Actuarial (gain) loss	(15)	6	(2)	(11)
Difference between expected return and actual return on plan assets	(15)			(15)
Difference between amortized and actuarial loss (gain) on accrued benefit obligation for year	16	(4)	2	14
Amortization of net transition (asset) obligation	(9)			(9)
Defined benefit (income) expense	(10)	6	3	(1)
Defined contribution option expense of registered pension plan	15			15
Net expense	$ 5	$ 6	$ 3	$ 14

Year ended Dec. 31, 2006	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	$ 4	$ 1	$ 2	$ 7
Interest cost	20	2	1	23
Actual return on plan assets	(35)			(35)
Actuarial (gain) loss	(1)	1		
Difference between expected return and actual return on plan assets	10			10

Difference between amortized and actuarial loss on accrued benefit obligation for year	4			4
Centralia coal mine closure charges	1			1
Amortization of net transition (asset) obligation	(9)			(9)
Defined benefit (income) expense	(6)	4	3	1
Defined contribution option expense of registered pension plan	17			17
Net expense	$ 11	$ 4	$ 3	$ 18

In 2008, 2007, and 2006, the entire net expense is related to continuing operations.

C. Status of Plans

Year ended Dec. 31, 2008	**Registered**	**Supplemental**	**Other**
Fair value of plan assets	**$ 279**	**$ 3**	**$**
Accrued benefit obligation	**324**	**47**	**20**
Funded status plan deficit	**(45)**	**(44)**	**(20)**
Amounts not yet recognized in financial statements:			
Unrecognized past service costs		**1**	**3**
Unamortized transition (asset) obligation	**(18)**	**1**	
Unamortized net actuarial gains	**72**	**9**	
Total recognized in financial statements:			
Accrued benefit asset (liability)	**$ 9**	**$ (33)**	**$ (17)**
Amortization period in years (EARSL)/(EARL) *(Note 2)*	**15**	**13**	**15**

Year ended Dec. 31, 2007	Registered	Supplemental	Other
Fair value of plan assets	$ 356	$ 2	$
Accrued benefit obligation	373	49	23
Funded status plan deficit	(17)	(47)	(23)
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	1	(1)	3
Unamortized transition (asset) obligation	(28)	2	
Unamortized net actuarial gains	42	15	4
Total recognized in financial statements:			
Accrued benefit liability	$ (2)	$ (31)	$ (16)
Amortization period in years (EARSL)	7	6	14

The current portion of the accrued benefit liability is included in accounts payable and accrued liabilities on the consolidated balance sheets. The long-term portion is included in deferred credits and other long-term liabilities.

Year ended Dec. 31, 2008	Registered	Supplemental	Other
Accrued current liabilities	**$**	**$**	**$ 1**
Other long-term (assets) liabilities	**(9)**	**33**	**16**
Accrued benefit liability	**$ (9)**	**$ 33**	**$ 17**

Year ended Dec. 31, 2007	Registered	Supplemental	Other
Accrued current liabilities	$	$	$ 1
Other long-term liabilities	2	31	15
Accrued benefit liability	$ 2	$ 31	$ 16

D. Contributions

Expected cash flows are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2009 (expected)	$ 9	$ 3	$ 2	$ 14
Expected benefit payments				
2009	26	2	2	30
2010	26	3	2	31
2011	27	3	2	32
2012	27	3	2	32

2013	28	3	2	33
2014-2018	142	18	10	170

E. Plan Assets

	Registered	Supplemental	Other
Fair value of plan assets at Dec. 31, 2006	$ 374	$ 2	$
Contributions	1	4	2
Benefits paid	(29)	(4)	(2)
Effect of translation on U.S. plans			
Actual return on plan assets[1]	10		
Fair value of plan assets at Dec. 31, 2007	$ 356	$ 2	$
Contributions	3	4	2
Benefits paid	(27)	(3)	(2)
Effect of translation on U.S. plans	2		
Actual return on plan assets[1]	(55)		
Fair value of plan assets at Dec. 31, 2008	**$ 279**	**$ 3**	**$**

1

Net of expenses.

The Corporation's investment policy is to seek a consistently high investment return over time while maintaining an acceptable level of risk to satisfy the benefit obligations of the pension plans. The goal is to maintain a long-term rate of return on the fund that at least equals the growth of liabilities, currently seven per cent. The pension fund may be invested in publicly traded common or preferred equity shares, rights or warrants, convertible debentures or preferred securities, bonds, debentures, mortgages, notes or other debt instruments of government agencies or corporations, private company securities, guaranteed investment contracts, term deposits, cash or money market securities, and mutual or pooled funds eligible for pension fund investment. The target allocation percentages are 60 per cent equity and 40 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investment decisions or as defensive reserves within the portfolios of each asset class. The fund may invest in derivatives for the purpose of hedging the portfolio or altering the desired mix of the fund. Derivative transactions that leverage the fund in any way are not permitted without the specific approval of the Corporation's pension committee.

The allocation of plan assets by major asset category at Dec. 31, 2008 and 2007 is as follows:

Year ended Dec. 31, 2008	**Registered**	**Supplemental**
Equity securities	**51%**	
Debt securities	**48%**	
Cash equivalents	**1%**	**100%**
Total	**100%**	**100%**

Year ended Dec. 31, 2007	**Registered**	**Supplemental**
Equity securities	58%	
Debt securities	41%	
Cash equivalents	1%	100%
Total	100%	100%

Plan assets include common shares of the Corporation having a fair value of $0.4 million at Dec. 31, 2008 (2007 $1 million). The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2008 (2007 $0.1 million).

F. Reconciliation of Accrued Benefit Obligation

	Registered	**Supplemental**	**Other**
Accrued benefit obligation as at Dec. 31, 2006	$ 399	$ 44	$ 24
Current service cost	4	2	1
Interest cost	19	2	2
Benefits paid	(29)	(4)	(2)
Effect of translation on U.S. plans	(1)		
Actuarial (gain) loss	(19)	5	(2)
Accrued benefit obligation as at Dec. 31, 2007	$ 373	$ 49	$ 23
Current service cost	3	1	1
Past service cost		2	
Interest cost	20	3	1
Benefits paid	(27)	(3)	(2)
Effect of translation on U.S. plans	4		1
Actuarial gain	(49)	(5)	(4)
Accrued benefit obligation as at Dec. 31, 2008	**$ 324**	**$ 47**	**$ 20**

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation was as follows:

Year ended Dec. 31, 2008	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation at Dec. 31			
Discount rate (%)	**7.2**	**7.3**	**7.1**

Rate of compensation increase (%)	**3.2**	**3.3**	
Benefit cost for year ended Dec. 31			
Discount rate (%)	**5.5**	**5.5**	**5.7**
Rate of compensation increase (%)	**3.7**	**3.8**	
Expected rate of return on plan assets (%)	**7.1**		
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)			**9.0-10.5**[1]
Dental care cost escalation (%)			**4.0**
Provincial health care premium escalation (%)			**2.5**

1

Decreasing gradually to 5 per cent by 2018 for Canadian plans and by 2017-2020 for U.S. plans and remaining at that level thereafter.

Year ended Dec. 31, 2007	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation at Dec. 31			
Discount rate (%)	5.5	5.5	5.7
Rate of compensation increase (%)	3.7	3.8	
Benefit cost for year ended Dec. 31			
Discount rate (%)	5.0	5.0	5.3
Rate of compensation increase (%)	3.8	3.8	
Expected rate of return on plan assets (%)	7.1		
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)			9.0-10.0[1]
Dental care cost escalation (%)			4.0
Provincial health care premium escalation (%)			2.5

1

Decreasing gradually to 5 per cent by 2015 for Canadian plans and by 2012 for U.S. plans and remaining at that level thereafter.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan.

35. Joint Ventures

Joint ventures at Dec. 31, 2008 included the following:

Joint venture		Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by Canadian Utilities
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, and is operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities in Alberta, operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia, operated by TransAlta
CE Generation LLC	50%	Geothermal and gas plants in the United States, operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta, operated by EPCOR Utilities Inc.
Wailuku	50%	A run-of-river generation facility in Hawaii, operated by MidAmerican
Keephills 3	50%	Coal-fired plant under construction in Alberta. The plant is being developed jointly with EPCOR Utilities Inc.

Summarized information on the results of operations, financial position and cash flows relating to the Corporation's pro-rata interests in its jointly controlled corporations was as follows:

	2008	2007	2006
Results of operations			
Revenues	**$ 619**	$ 609	$ 611
Expenses	**(494)**	(454)	(457)
Non-controlling interests	**(55)**	(44)	(42)
Proportionate share of net earnings	**$ 70**	$ 111	$ 112
Cash flows			
Cash flow from operations	**$ 273**	$ 112	$ 115
Cash flow used in investing activities	**(376)**	(147)	(44)
Cash flow from (used in) financing activities	**30**	(93)	(52)
Proportionate share of (decrease)/increase in cash and cash equivalents	**$ (73)**	$ (128)	$ 19
Financial position			
Current assets	**$ 166**	$ 91	$ 147
Long-term assets	**2,144**	1,924	1,850
Current liabilities	**(202)**	(144)	(117)
Long-term liabilities	**(503)**	(390)	(503)
Non-controlling interests	**(351)**	(373)	(394)

Proportionate share of net assets	**$ 1,254**	$ 1,108	$ 983

36. Subsequent Events

Sundance Unit 4 Derate

On Feb. 10, 2009, TransAlta reported the first quarter financial impact of an extended derate at Unit 4 of the Sundance thermal plant ("Unit 4"). The facility experienced an unplanned outage in December 2008 related to the failure of an induced draft ("ID") fan. At that time, Unit 4, which has a capacity of 406 MW, had been derated to approximately 205 MW. The repair of the ID fan components by the original equipment manufacturer took longer than planned, and therefore, Unit 4 did not return to full service until Feb. 23, 2009. As a result of the extended derate, first quarter production was reduced by 328 GWh and net income declined by $17 million.

TransAlta has given notice of a High Impact Low Probability Event to the PPA Buyer and the Balancing Pool, which if successful, will protect the Corporation from the financial loss and related penalties. The available penalties that TransAlta expects to recover in net income are anticipated to be $14 million.

Keephills Units 1 and 2 Uprates

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

Dividend Increase

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

Carbon Capture and Storage

On Jan. 27, 2009, the Government of Canada announced in the 2009 federal budget an additional $850 million of funding that has been earmarked to support the development of carbon capture and storage technologies. The impact of this announcement on the Corporation cannot be reasonably determined at this time because specific information regarding the use, distribution timelines, and recipients of the funding have not been clarified by the government.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	**2008**	2007	2006	2005
Financial Summary				
Earnings Statement				
Revenues	**$ 3,110**	$ 2,775	$ 2,677	$ 2,664
Operating income	**$ 533**	$ 541	$ 157	$ 421
Net earnings applicable to common shareholders	**$ 235**	$ 309	$ 45	$ 199
Balance Sheet				
Total assets	**$ 7,815**	$ 7,157	$ 7,460	$ 7,741
Short-term debt, net of cash and cash equivalents	**$ 393**	$ 600	$ 296	$ (66)
Long-term debt	**$ 2,365**	$ 1,837	$ 2,221	$ 2,605
Preferred shares of a subsidiary	**$**	$	$	$
Other non-controlling interests	**$ 469**	$ 496	$ 535	$ 559
Preferred securities	**$**	$	$ 175	$ 175
Common shareholder's equity	**$ 2,510**	$ 2,299	$ 2,428	$ 2,543
Total invested capital	**$ 5,737**	$ 5,232	$ 5,655	$ 5,756
Cash Flow				
Cash flow from operating activities	**$ 1,038**	$ 847	$ 490	$ 619
Cash flow used in investing activities	**$ (581)**	$ (410)	$ (261)	$ (242)
Common Share Information (per share)				
Net earnings	**$ 1.18**	$ 1.53	$ 0.22	$ 1.01
Dividends declared	**$ 1.08**	$ 1.00	$ 1.00	$ 1.00
Book value (at year-end)	**$ 12.70**	$ 11.39	$ 11.99	$ 12.80
Market price:				
High	**$ 37.50**	$ 34.00	$ 26.91	$ 26.66
Low	**$ 21.00**	$ 23.79	$ 20.22	$ 17.67
Close (TSX at Dec. 31)	**$ 24.30**	$ 33.35	$ 26.64	$ 25.41
Ratios (percentage except where noted)				
Debt/invested capital	**48.1**	46.8	44.5	43.9
Return on common shareholder's equity	**9.8**	13.1	1.8	7.0
Return on invested capital	**7.8**	9.8	2.4	7.1
Cash flow to total debt	**31.1**	30.7	26.2	23.0
Cash flow to interest coverage (times)	**7.2**	6.6	5.5	4.7
Dividend payout	**91.5**	65.6	447.7	113.0
Dividend yield	**4.4**	3.0	3.8	3.9
Price/earnings multiple	**20.6**	21.8	121.1	26.7
Weighted average common shares for the year (in millions)	**199**	202	201	197
Common shares oustanding at Dec. 31 (in millions)	**198**	201	202	199
Statistical Summary				
Number of employees	**2,200**	2,201	2,687	2,657
Generating Capacity (net MW)3				
Hydro	**807**	807	807	802
Coal	**4,942**	4,942	4,887	4,885

Gas	**1,913**	1,960	1,953	1,933
Renewables	**411**	315	315	315
Total generating capacity	**8,073**	8,024	7,962	7,935
Total generation production (GWh)[4]	**48,891**	50,395	48,213	51,810

Prior years have not been restated to conform with the current year's presentation.

1 2002 and 2001 Energy Marketing real-time trading contract revenues restated to be presented on a gross basis.

2 Includes discontinued operations.

3 Represents TransAlta's ownership.

4 Includes discontinued operations.

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt cash and cash equivalents)/(debt + preferred securities + non-controlling interests + common equity)

Return on common shareholder's equity = net earnings excluding gain on discontinued operations/average of opening and closing common equity

2004	2003	2002	2001	2000	1999	1998
$ 2,838	$ 2,509	$ 1,815[1]	$ 2,560[1]	$ 1,587	$ 1,029	$ 1,090
$ 478	$ 554	$ 224[2]	$ 469[2]	$ 605[2]	$ 442	$ 660[2]
$ 170	$ 234	$ 190	$ 215	$ 280	$ 170	$ 211
$ 8,133	$ 8,420	$ 7,420	$ 7,878	$ 7,627	$ 6,038	$ 5,393
$ (103)	$ (35)	$ 146	$ 475	$ 221	$ (173)	$ (149)
$ 3,058	$ 3,162	$ 2,707	$ 2,511	$ 2,201	$ 2,177	$ 1,904
$	$	$	$	$ 122	$ 268	$ 268
$ 616	$ 478	$ 263	$ 281	$ 253	$ 377	$ 503
$ 175	$ 451	$ 452	$ 453	$ 292	$ 287	$
$ 2,473	$ 2,460	$ 2,040	$ 1,990	$ 1,957	$ 1,836	$ 1,855
$ 6,061	$ 6,516	$ 5,608	$ 5,710	$ 5,046	$ 4,772	$ 4,381
$ 613	$ 757	$ 438	$ 716	$ 189	$ 422	$ 471
$ (65)	$ (535)	$ (36)	$ (1,077)	$ (205)	$ (989)	$ (137)
$ 0.88	$ 1.26	$ 1.12	$ 1.27	$ 1.66	$ 1.00	$ 1.31
$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 0.99
$ 12.74	$ 12.90	$ 12.01	$ 11.82	$ 11.61	$ 10.85	$ 10.94
$ 18.75	$ 19.55	$ 23.95	$ 30.13	$ 22.55	$ 25.15	$ 25.40
$ 15.25	$ 15.36	$ 16.69	$ 19.15	$ 13.20	$ 12.25	$ 18.20
$ 18.05	$ 18.53	$ 17.11	$ 21.60	$ 22.00	$ 14.15	$ 22.60
47.4	47.9	50.9	52.3	48.0	45.6	40.0
6.5	10.3	3.5	10.9	11.7	9.2	12.3
7.5	9.1	4.0	8.7	12.3	9.7	15.4
18.5	17.9	16.1	21.8	25.3	21.7	22.8
4.1	3.3	3.8				
120.0	79.0	241.8	78.5	75.8	99.7	75.8
5.5	5.4	5.8	4.6	4.6	7.1	4.4
21.7	14.7	41.7	17.3	16.7	14.2	17.3
193	185	170	169	169	170	161
194	191	170	168	169	169	170
2,505	2,563	2,573	2,656	2,363	2,679	2,455
802	801	801	800	800	800	800
4,778	4,777	4,966	5,090	5,016	3,676	3,676
2,444	2,499	1,333	1,108	1,054	1,464	1,008
313	245	44				
8,337	8,322	7,144	6,998	6,870	5,940	5,484
54,560	53,134	46,877	44,136	40,644	37,771	39,001

Return on invested capital = earnings before non-controlling interests + income taxes + net interest expense/average annual

Dividend yield = common share dividends/current year's close price *invested capital*

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

Price/earnings multiple = current year's close/basic earnings per share from continuing operations

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