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

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

For the fiscal year ended December 31, 2010 Commission file number 001-15214

TRANSALTA CORPORATION

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

Not 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:

x Annual information form **x** 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, 2010, 220,343,708 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 **x**

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 **x** No **o**

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes **x** No **o**

INCORPORATION BY REFERENCE

The documents 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	333-162418
F-10	333-170465

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 Exhibit 13.3 incorporated by reference herein. For the related supplementary note entitled "Reconciliation to United States Generally Accepted Accounting Principles" containing a reconciliation of the important differences between Canadian and United States generally accepted accounting principles, see Exhibit 13.4 incorporated by reference herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see Exhibit 13.2 incorporated by reference herein.

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, 2010, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

MANAGEMENT'S ANNUAL 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, 2010 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, 2010. 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, 2010. For Ernst & Young LLP's report see page 3 of the Consolidated Annual Financial Statements for the year ended December 31, 2010 filed as Exhibit 13.3 and incorporated by reference herein, 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, Wailuku, CE Generation and Genesee 3 joint ventures

(collectively, the "Excluded Entities"), in accordance with Frequently Asked Questions Nos. 1 and 15 of "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 Securities and Exchange Commission (revised September 24, 2007) (the "FAQ"). 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 contro l 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 as of and for the year ended December 31, 2010 in the amount of $1,454 million of the Company's total assets, $804 million of net assets, $344 million of revenues and $64 million of net earnings. 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 controls 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. Each of Mr. Gordon S. Lackenbauer and Mrs. Karen E. Maidment 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 fina ncial 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 Securities and Exchange Commission. 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 2010 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2010 and December 31, 2009, Ernst & Young LLP and its affiliates were paid $3,499,254 and $3,562,032 respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31	**2010**	**2009**
Audit Fees	$ 2,737,081	$ 2,679,080
Audit-related fees	729,873	824,631
Tax fees	32,300	58,321
Total	**$ 3,499,254**	**$ 3,562,032**

No other audit firms provided audit services in 2010 or 2009.

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 2010 include payments related to 2009 in the amount of $969,568. Total audit fees for 2009 include payments related to 2008 in the amount of $1,212,080.

Audit-Related Fees

The audit-related fees in 2010 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, other audits, public equity and debt offerings, and miscellaneous accounting advice provided to the Corporation. The audit-related fees in 2009 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, public equity and debt offerings and miscellaneous accounting advice provided to the Corporation.

Tax Fees

The majority of tax fees for each of 2009 and 2010 relate to various tax related matters in our foreign operations.

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 (the "**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. The Policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at

its next regularly scheduled meeting. In 2009 the ARC granted management the authority to approve*de minimus* permissible non-audit services (which are in the aggregate the lesser of 5 per cent of the total fees paid to the external auditors or $125,000) provided such services are reported to the ARC at its next scheduled meeting.

Percentage of Services Approved by the ARC

For the year ended December 31, 2010, 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 27 of Exhibit 13.2, incorporated by reference herein.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 27 of Exhibit 13.2, incorporated by reference herein, under the heading "Liquidity and Capital Resources" and page 40 of Exhibit 13.3, incorporated by reference herein, 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)
C. Kent Jespersen
Gordon S. Lackenbauer
Karen E. Maidment
Donna S. Kaufman (ex-officio member)

FORWARD LOOKING INFORMATION

This Form 40-F, 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 and on management's experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or ot her 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.

In particular, this Form 40-F and the documents incorporated herein by reference contain forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and upgrades, and their attendant costs; expectations related to future earnings and cash flow from operating activities; expectations relating to the timing of the completion of the study regarding CCS and the cost of the study; estimates of fuel supply and demand conditions and the costs of procuring fuel; our plans to invest in existing and new capacity, and the expected return on those investments; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and ma intenance, and the variability of those costs; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; expectations relating to the renegotiation of certain of the collective bargaining agreements to which we are a party; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; expectations for the outcome of existing or potential legal/administrative claims; and expectations for the ability to access capital markets at reasonable terms.

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 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) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate the Corporation's facilities; (ix) natural disasters; (x) equipmen t failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) the Corporation's provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in TransAlta's Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2010 (the "**Annual MD&A**") incorporated herein by reference.

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 occur to a different extent or at a different time than the Corporation has described or might not occur. The Corporation cannot assure you that projected results or events will be achieved.

DOCUMENTS FILED AS PART OF THIS REPORT AND EXHIBITS

The following items are specifically incorporated by reference in, and form an integral part of, this filing on Form 40-F:

13.1 TransAlta Corporation Annual Information Form for the year ended December 31, 2010.

13.2 Related Management's Discussion and Analysis.

13.3 Consolidated Audited Annual Financial Statements for the year ended December 31, 2010.

13.4	Reconciliation to United States Generally Accepted Accounting Principles of the 2010 Consolidated Audited Annual Financial Statements.
13.5	Management's Annual Report on Internal Control over Financial Reporting, (included on page 2 of Exhibit 13.3 filed herewith).
13.6	Independent Auditor's Report on Internal Controls under Standards of the Public Company Accounting Oversight Board (United States), (included on page 3 of Exhibit 13.3 filed herewith).
23.1	Consent of Ernst and Young LLP Chartered Accountants.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
31.2	Certification of Chief Financial Officer pursuant to Section 302 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*.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the *Sarbanes-Oxley Act of 2002*.

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/ Brett Gellner
Brett Gellner
Chief Financial Officer

Dated: February 24, 2011

EXHIBIT INDEX

13.1	TransAlta Corporation Annual Information Form for the year ended December 31, 2010.
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Exhibit 13.1

TRANSALTA CORPORATION

2011 RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2010

FEBRUARY 24, 2011

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form (“ **Annual Information Form**” or “**AIF**”) is given as at or for the year ended December 31, 2010. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles.

The Accounting Standards Board (“**AcSB**’) of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to prepare interim and annual financial statements using International Financial Reporting Standards (“**IFRS**”), as issued by the International Accounting Standards Board, effective January 1, 2011. Effective January 1, 2011, TransAlta Corporation (“**TransAlta**” or “**Corporation**”) will begin reporting under IFRS. For more information on TransAlta’s conversion project, see TransAlta’s MD&A under “Future Accounting Changes – IFRS Convergence”.

SPECIAL NOTE REGARDING FORWARD LOOKING INFORMATION

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 and on management’s experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements

are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “anticipate”, “intend”, “plan”, “foresee”, “potential”, “enable” , “continue” or other comparable terminology. These statements are not guarantees of 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.

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

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 including reclamation of lands; (iv) changes in general economic conditions including interest rates; (v) operational risks involving the Corporation’s facilities, including unplanned outages at such facilities; (vi) natural disasters; (vii) equipment failure; (viii) disruptions in the transmission and distribution of electricity; (iv) effects of weather; (x) disruptions in the source of fuels, water, wind or biomass required to operate the Corporation’s facilities; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) the Corporation’s provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel; (xxi) labour relations matters; and (xxii) development projects and acquisitions on time and expected costs. 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, 2010 (the “**Annu al 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 occur to a different extent or at a different time than the Corporation has described 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, 2010 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

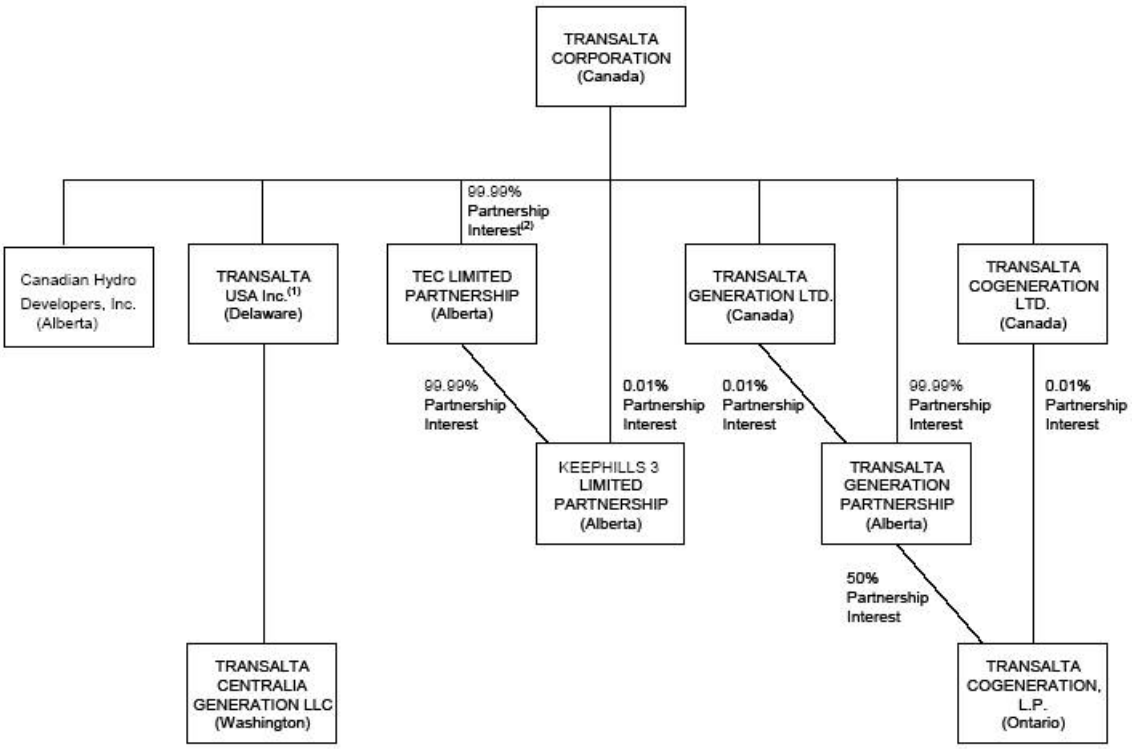
TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* (the “**CBCA**”) on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving the Corporation and TransAlta Utilities Corporation (“**TransAlta Utilities**” or “**TAU**”) under the CBCA. 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 again issued a Certificate of Amalgamation under the CBCA in connection with the amalgamati on 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 are at 110 - 12 th Avenue S.W., Calgary, Alberta, Canada, T2R 0G7.

Intercorporate Relationships

Effective January 1, 2009, the Corporation completed the 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 CBCA. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of certain win d assets, and some of which are now held indirectly, in the case of both the former generation assets and businesses of TAU and TEC and the assets and business of Canadian Hydro Developers, Inc. (“**Canadian Hydro**”). TransAlta completed its acquisition of Canadian Hydro on November 4, 2009.

As of December 31, 2010, the principal subsidiaries of the Corporation and their respective jurisdictions of formation are set out below:



Notes:
(1) TransAlta USA Inc. is an indirect subsidiary of TransAlta.
(2) The remaining 0.01 per cent interest in TEC Limited Partnerships is owned by TransAlta (Ft. McMurray) Ltd., a wholly owned subsidiary of TransAlta.

Unless the context otherwise requires, all references to the " **Corporation**" and to "**TransAlta**", "**we**", "**our**" and "**us**" 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 8,641 megawatts ("**MW**") of generating capacity[1] operating in facilities having approximately 10,452 MW of aggregate generating capacity. In addition, the Corporation has facilities under construction with a net ownership interest of 305 MW of generating capacity in facilities designed to have aggregate generating capacity of 530 MW, for total net ownership of 8,946 MW of generating capacity in facilities that have or will have aggregate capacity of 10,982 MW. 0; The Corporation is focused on generating electricity in Canada, the United States and Australia through its diversified portfolio of facilities fuelled by coal, natural gas, hydroelectric, wind, geothermal and biomass resources.

In Canada, the Corporation holds a net ownership interest of 6,362 MW of electrical generating capacity in thermal, natural gas-fired, wind powered, hydroelectric and biomass facilities, including 5,098 MW in Western Canada, 1,040 MW in Ontario, 99 MW in Québec and 125 MW in New Brunswick.

[1] TransAlta measures capacity as the net maximum capacity ("**NMC**") that a unit can sustain over a period of time, which is consistent with the 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.

In the United States, the Corporation's principal facilities include a 1,340 MW thermal facility and a 248 MW natural 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 natural gas-fired facilities in Texas, Arizona and New York. In addition, the Corporation 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 natural 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, natural gas, hydro, wind, geothermal and biomass fuelled facilities.

TransAlta's Map of Operations

The following map outlines TransAlta's operations as of December 31, 2010.



GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation is organized into three business segments, Generation, Energy Trading [2] and Corporate. The Generation group is responsible for constructing, operating and maintaining our electricity generation facilities. The Energy Trading group is responsible for the wholesale trading of electricity and other energy-related commodities and derivatives. It is also responsible for the management of available generating capacity as well as the fuel and transmission needs of the Generation business. Both segments are supported by a corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, investor and government relations, information technology, human resources, internal audit, and other administrative support.

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 18, 2011, the PPA Buyer for our Sundance 1 and 2 facilities provided notice that it intends to dispute our notices of force majeure and termination for destruction, which we provided under the terms of the Sundance A Power Purchase Arrangement ("**PPA**"). They also advised that they intend to pursue the dispute resolution process set out under the terms of the PPA. Although no assurance can be given as to the ultimate outcome of these matters, we believe that they will be resolved in our favour . We remain committed to continuing to work with the PPA Buyer and the Balancing Pool under the processes established within the PPA.

- On February 8, 2011, TransAlta issued notice of termination for destruction on its Sundance 1 and 2 coal-fired generation units under the terms of the PPA. This action was based on our determination that the physical state of the boilers is such that the units cannot be economically restored under the terms of the PPA. Under the PPA, termination for destruction permits the recovery of the net book value specified in the PPA.

- On January 4, 2011, TransAlta declared force majeure for its Sundance 1 and 2 coal-fired generation units related to boiler tube conditions. All 560 MW from Sundance 1 and 2 were at the time determined to be unavailable from December 16 and December 19 respectively, until February 15, as the units were taken offline for inspection to determine the scope of required repairs. The decision to shut down the units was made on the basis of the Alberta Boiler Safety Association (**"ABSA"**), which i

ndicated that immediate shut down of the units was appropriate action and consistent with industry safety standards. The units cannot be restarted without ABSA inspection and approval. Under the terms of its PPA for these units, TransAlta notified the PPA buyer and the Balancing Pool of a force majeure event. For the duration of the force majeure period, TransAlta is entitled to receive its PPA capacity payments and is protected from having to pay penalties for the units' lack of availability, to the extent the event meets the force majeure criteria set out in the PPA. While we believe that this event qualifies for force majeure, no assurances can be given.

- On December 20, 2010, TransAlta Cogeneration, L.P. (" **TA Cogen**"), a partnership that is owned indirectly 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. The sale is expected to close in early 2011.

Generation and Business Development

2010

- On December 6, 2010, the Corporation announced it had commissioned 123 MW from two new wind facilities, both ahead of schedule and on budget. The $135 million Ardenville wind facility, located about eight kilometres south of Fort Macleod, Alberta, involved the installation of 23 Vestas V90-3.0

[2] Our Energy Trading segment was referred to as "Commercial Operations and Development" in our prior AIFs.

MW wind turbines. The Corporation had announced plans to design, build and operate Ardenville, in southern Alberta on April 28, 2009. The facility has an installed capacity of 69 MW. Included in the capital cost of the project is the purchase of an already operational 3 MW turbine at Macleod Flats.

The $100 million expansion of the Kent Hills wind facility, located about 33 kilometres southwest of Moncton, New Brunswick, has increased the existing generation capacity of the facility by 54 MW to 150 MW with the installation of 18 Vestas V90-3.0 MW wind turbines. On January 11, 2010, the Corporation announced that it had been awarded a 25-year power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation ("**New Brunswick Power**") for this additional wind power. The 96 MW Kent Hills Wind Farm began commercial operation on December 31, 2008 and consisted of 32 Vestas V90-3.0 MW wind turbines. The capacity from this project is also sold under a power purchase agreement with New Brunswick Power.

- On October 29, 2010 the Corporation announced it is proceeding with the addition of a 15 MW efficiency uprate at its Sundance 3 unit in Alberta. The Sundance unit will be upgraded to 368 MW and is expected to be operational by the end of 2012. The total capital cost of the uprate is estimated at $27 million.

- On June 28, 2010, the Corporation together with Enbridge Inc. announced that Enbridge is participating in the development of Project Pioneer, Canada's first fully-integrated carbon capture and storage ("**CCS**") project involving retro-fitting a coal-fired electricity plant. Enbridge brings to Project Pioneer expertise in the design and construction of pipeline infrastructure, as well as extensive knowledge in CO_2 sequestration.

- On June 7, 2010, the Corporation announced it had declared force majeure due to the mechanical failure of critical generator components at its 353 MW Sundance 3 thermal plant located in Wabamun, Alberta. The unit is expected to return to full capability after a major maintenance outage is completed in 2012 due to the 18 - 24 month lead time required to acquire a new generator stator winding.

- On April 26, 2010, the Corporation and the Governor of Washington State signed a memorandum of understanding (" **MOU**"), to enter discussions on an agreement to significantly reduce greenhouse gas emissions from the Centralia coal-fired plant and provide replacement capacity by 2025. The MOU set forth clear objectives and a definitive timeline to develop an agreement to transition the State to cleaner energy sources while protecting jobs and the local economy. The MOU also recognizes the need to protect the value that Centralia brings to TransAlta's shareholders.

- On April 1, 2010, the Corporation announced that, after 54 years, it has fully retired all the units of its Wabamun power plant. On March 31, 2010, the last operating unit ended commercial operation. Over the next several years TransAlta will complete the Wabamun remediation and reclamation work as approved by the Government of Alberta.

2009

- On November 17, 2009, the Corporation hosted its second Alberta fixed price power auction, whereby customers were able to lock in wholesale power volumes for 2010 through 2013 at competitive market prices.

- On November 4, 2009, TransAlta completed the acquisition, through a wholly-owned subsidiary, of all of the issued and outstanding common shares of Canadian Hydro for aggregate cash consideration of $755.0 million. At closing of the acquisition, Canadian Hydro operated 694 MW of wind, hydro and biomass facilities in British Columbia, Alberta, Ontario and Québec and also had 18 MW under construction.

- Effective September 30, 2009, the Corporation signed a new long-term contract with the Ontario Power Authority (the " **OPA**") for the Sarnia regional natural gas cogeneration power plant. The contract is capacity based and has a term from July 1, 2009 to December 31, 2025. While the specific terms and conditions of the contract are confidential, the OPA has indicated that the agreement is in line with other similar agreements executed by the OPA.

- On May 20, 2009, the Corporation announced that it would advance a major maintenance outage on its 353 MW Sundance 3 facility from the second quarter of 2010 into the second and third quarters of 2009.

- 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 328 gigawatt hour ("**GWh**") and net earnings declined by approximately $10 million. On April 27, 2009, the Balancing Pool, an entity establi shed by the Government of Alberta, rejected the Corporation's assertion that this outage should be regarded as a High Impact Low Probability Force Majeure Event. As required by the PPA legislation, the Corporation was required to pay the penalties related to the derate. The Corporation settled the issue in the third quarter and the terms of the settlement are confidential.

- On January 29, 2009, the Corporation announced that it would 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 2012. The total capital cost of the projects is estimated to be $68 million.

2008

- 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 natural gas/diesel combined cycle natural gas plant in Campeche, a 259 MW combined cycle natural gas plant in Chihuahua and all associated commercial arrangements.

- On May 27, 2008, the Corporation announced that, commencing in 2009, it would be constructing a 66 MW expansion at our Summerview facility in southern Alberta. The project will consist of 22 Vestas V90-3.0 MW wind turbines. The Summerview 2 facility commenced commercial operations on February 23, 2010. Total capital cost of the project was $118 million.

- 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 was approximately $77 million and commercial operations commenced in November 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.

- On February 20, 2008, the Corporation announced it had signed a purchase and sale agreement with Intergen Global Ventures B.V. ("**Intergen**") 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 cost for this Blue Trail wind power project was $113 million. The capacity from this project is sold on the Alberta Power Pool.

Corporate Matters

2010

- On December 10, 2010, the Corporation issued $300 million principal amount of 4.60% cumulative rate reset preferred shares for net proceeds to the Corporation of $291.2 million.

- On November 28, 2010, the Corporation and the Global Carbon Capture and Storage Institute announced that Project Pioneer, the Corporation's CCS project, has been awarded $5 million AUD funding to further CCS knowledge sharing. Project Pioneer is Canada's first fully-integrated CCS project involving retro-fitting a coal-fired electricity plant. Project Pioneer will contribute to and access international research and leading-edge knowledge from a global CCS forum. On June 28, 2010, the Corporation together with Enbridge Inc. announced that Enbridge is participating in the development of Project Pioneer. Enbridge brings to Project Pioneer expertise in the design and constr uction of pipeline infrastructure as well as extensive knowledge in CO_2 sequestration. On October 14, 2009, the federal and provincial governments announced that Project Pioneer, had received committed funding of more than $750 million. Joining the Corporation and Alstom as a participant in the development of Project Pioneer is Capital Power L.P. The Corporation is the managing partner of this joint government-industry partnership. The funding will also support the undertaking of a Front End Engineering and Design ("**FEED**") study, expected to be completed by the end of 2011. Construction of the facility, if supported by the study, would be targeted for completion in 2015 - 18. Project Pioneer was first announced on April 3, 2008, as an agreement with Alstom Canada Inc. to develop the one million tonne/year CCS project at one of T ransAlta's coal-fired power stations in Alberta.

- On June 23, 2010, the Corporation responded to the federal government's recent policy announcement mandating the phased end of coal-fired electricity generation in Canada. Under Ottawa's proposal, power companies would have to close their coal-fired facilities at 45 years of age, or the end of their power purchase arrangements, whichever is later. Companies would be

prohibited from making investments to extend the lives of those plants unless emission levels can be reduced to levels equivalent to those of a natural gas combined cycle plant.

- On March 12, 2010, the Corporation issued US$300 million principal amount of 6.50% senior notes maturing March 15, 2040 for net proceeds to the Corporation of US$293.3 million.

2009

- On November 18, 2009, the Corporation issued $400 million principal amount of 6.4% medium term notes maturing November 18, 2019 for net proceeds to the Corporation of $397.2 million.

- On November 13, 2009, the Corporation issued US$500 million principal amount of 4.75% senior notes maturing January 15, 2015 for net proceeds to the Corporation of US$495.9 million.

- On November 5, 2009, the Corporation completed a public offering of 20,522,500 common shares at a price of $20.10 per common share, resulting in net proceeds to the Corporation of $396.0 million.

- On October 14, 2009, the federal and provincial governments announced that the Corporation's CCS project, Project Pioneer, had received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will also support the undertaking of a FEED study. The FEED study is expected to cost $20 million: $10 million will come from the federal government; $5 million will come from the provincial government; and $5 million will come from the Corporation and the other industry partners. Construction of the facility, if supported as expected by the study, would be targeted for start-up in 2015. The Corporation is the managing partner of the joint government-industry partnership.

- On May 29, 2009, the Corporation issued $200 million principal amount of 6.45% medium term notes maturing May 29, 2014 for net proceeds to the Corporation of $198.9 million.

- On January 29, 2009, the Board of Directors of the Corporation (the " **Board**") 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.

- Effective January 1, 2009, the Corporation completed a reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, an 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 a 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 CBCA.& #160; TransAlta remains the holding entity of the various businesses of the Corporation, some of which are held directly, in the case of the wind assets, and some of which are held indirectly, in the case of the former generation assets and businesses of TAU and TEC.

2008

- On May 9, 2008, the Corporation issued US$500 million principal amount of 6.65% senior notes maturing May 15, 2018 for net proceeds to the Corporation of US$495.4 million.

- On February 1, 2008, the Board 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.

BUSINESS OF TRANSALTA

Generation Business Segment

The Generation business segment is responsible for constructing, operating and maintaining the Corporation's electricity generation facilities. The following table summarizes the Corporation's generation facilities which are operating, under construction or under development, as at December 31, 2010. Subsequent sections provide more detailed information on facilities by geographic location and fuel type.

Western Canada

Facility	Capacity (MW) [1]	Ownership (%)	Net Capacity Ownership Interest [1]	Fuel	Revenue Source	Contract Expiry Date
Sundance[2][3]	2,141	100	2,141	Coal	Alberta PPA / Merchant[3]	2017, 2020
Keephills [4]	812	100	812	Coal	Alberta PPA/Merchant[4]	2020
Keephills 3 [5]	450	50	225	Coal	Merchant	-
Sheerness	780	25	195	Coal	Alberta PPA	2020

Genesee 3	450	50	225	Coal	Merchant	-
Fort Saskatchewan	118	30	35	Natural gas	Long-term contract ("**LTC**")	2019
Meridian	220	25	55	Natural gas	LTC	2024
Poplar Creek	356	100	356	Natural gas	LTC/Merchant	2024
Blue Trail	66	100	66	Wind	Merchant	-
Castle River (6)	44	100	44	Wind	LTC/Merchant	2011
Cowley North	20	100	20	Wind	Merchant	-
Cowley Ridge	21	100	21	Wind	Merchant	-
Macleod Flats	3	100	3	Wind	Merchant	-
McBride Lake	75	50	38	Wind	LTC	2023
Sinnott	7	100	7	Wind	Merchant	-
Soderglen	71	50	35	Wind	Merchant	-
Summerview 1 (7)	70	100	70	Wind	Merchant	-
Summerview 2	66	100	66	Wind	Merchant	-
Taylor Wind	3	100	3	Wind	Merchant	-
Ardenville	69	100	69	Wind	Merchant	-
Akolkolex	10	100	10	Hydro	LTC	2015
Barrier	13	100	13	Hydro	Alberta PPA	2020
Bearspaw	17	100	17	Hydro	Alberta PPA	2020
Belly River	3	100	3	Hydro	Merchant	-
Big Horn	120	100	120	Hydro	Alberta PPA	2020
Bone Creek (5)	19	100	19	Hydro	LTC	2031
Brazeau	355	100	355	Hydro	Alberta PPA	2020
Cascade	36	100	36	Hydro	Alberta PPA	2020
Ghost	51	100	51	Hydro	Alberta PPA	2020
Horseshoe	14	100	14	Hydro	Alberta PPA	2020
Interlakes	5	100	5	Hydro	Alberta PPA	2020
Kananaskis	19	100	19	Hydro	Alberta PPA	2020
Pingston	45	50	23	Hydro	LTC	2023
Pocaterra	15	100	15	Hydro	Alberta PPA	2013
Rundle	50	100	50	Hydro	Alberta PPA	2020
Spray	103	100	103	Hydro	Alberta PPA	2020
St. Mary	2	100	2	Hydro	Merchant	-
Taylor Hydro	13	50	6	Hydro	Merchant	-
Three Sisters	3	100	3	Hydro	Alberta PPA	2020
Upper Mamquam	25	100	25	Hydro	LTC	2025
Waterton	3	100	3	Hydro	Merchant	-
GPEC	25	100	25	Biomass	LTC	2019-2024
Total Western Canada	**6,788**		**5,403**			

Eastern Canada

Facility	Capacity (MW) (1)	Ownership (%)	Net Capacity Ownership Interest (1)	Fuel	Revenue Source	Contract Expiry Date
Mississauga	108	50	54	Natural gas	LTC	2017
Ottawa	68	50	34	Natural gas	LTC	2012
Sarnia (8)	506	100	506	Natural gas	LTC	2022-2025
Windsor	68	50	34	Natural gas	LTC/Merchant	2016
Kent Hills	150	83	125	Wind	LTC	2033-2035
Le Nordais	99	100	99	Wind	LTC	2033
Melancthon	200	100	200	Wind	LTC	2026-2028
Wolfe Island	198	100	198	Wind	LTC	2029
Appleton	1	100	1	Hydro	LTC	2011
Galetta	2	100	2	Hydro	LTC	2011
Misema	3	100	3	Hydro	LTC	2027
Moose Rapids	1	100	1	Hydro	LTC	2011
Ragged Chute	7	100	7	Hydro	LTC	2011
Total Eastern Canada	**1,411**		**1,264**			

US

Facility	Capacity (MW) (1)	Ownership (%)	Net Capacity Ownership Interest (1)	Fuel	Revenue Source	Contract Expiry Date
Centralia(9)	1,340	100	1,340	Coal	Merchant	-
Centralia Natural gas	248	100	248	Natural gas	Merchant	-
Power Resource	212	50	106	Natural gas	Merchant	-
Saranac	240	37.5	90	Natural gas	Merchant	-
Yuma	50	50	25	Natural gas	LTC	2024
Imperial Valley Geothermal Facilities (10)	327	50	164	Geothermal	LTC	2016-2029
Skookumchuck (11)	1	100	1	Hydro	LTC	2020
Wailuku	10	50	5	Hydro	LTC	2023
Total US	**2,428**		**1,979**			

Australia

Facility	Capacity (MW) [1]	Ownership (%)	Net Capacity Ownership Interest [1]	Fuel	Revenue Source	Contract Expiry Date
Parkeston	110	50	55	Natural gas	LTC	2016
Southern Cross[12]	245	100	245	Natural gas/Diesel	LTC	2013
Total Australia	**355**		**300**			
TOTAL	**10,982**		**8,946**			

Notes:
(1) MW are rounded to the nearest whole number.
(2) Please refer to Recent Developments in this AIF for information with respect to our Sundance 1 and 2 units.
(3) Merchant capacity refers to 15 MW (under development), 53 MW, 53 MW and 44 MW uprates on units 3, 4, 5 and 6, respectively.
(4) Includes two 23 MW uprates on units 1 and 2, both expected to be commercial in 2012. Merchant capacity refers to these two uprates.
(5) These facilities are currently under development.
(6) Includes seven additional turbines at other locations.
(7) Comprised of two facilities.
(8) Sarnia's 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 ten facilities.

(11) This facility is used to provide a reliable water supply to TransAlta's other generation facilities at Centralia.
(12) Comprised of four facilities.

Canada: Western Canada

Thermal Facilities

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

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Sundance	AB	Sundance Unit No. 1[1]	280	100	1970	2017
	AB	Sundance Unit No. 2[1]	280	100	1973	2017
	AB	Sundance Unit No. 3[2]	368	100	1976	2020
	AB	Sundance Unit No. 4	406	100	1977	2020
	AB	Sundance Unit No. 5	406	100	1978	2020
	AB	Sundance Unit No. 6	401	100	1980	2020
Keephills	AB	Keephills Unit No. 1[3]	406	100	1983	2020
	AB	Keephills Unit No. 2[3]	406	100	1984	2020
	AB	Keephills Unit No. 3[4]	450	50	2011	-
Sheerness	AB	Sheerness Unit No. 1	390	25	1986	2020
	AB	Sheerness Unit No. 2	390	25	1990	2020
Genesee	AB	Genesee 3	450	50	2005	-
Total			**4,633**			

Notes:
(1) Please refer to Recent Developments in this AIF for information with respect to our Sundance 1 and 2 units.
(2) Includes a 15 MW uprate expected to be commercial in 2012.
(3) Includes two 23 MW uprates on units 1 and 2, both expected to be commercial in 2012.
(4) This facility is currently under development.

The Sundance and Keephills facilities (the "**Alberta thermal plants**") are located approximately 70 kilometres west of Edmonton, Alberta and are owned by TransAlta. The Sheerness facility is located approximately 200 kilometres northeast of Calgary, Alberta and is jointly owned by TA Cogen, an Ontario limited partnership, and ATCO Power (2000) Ltd. ("**ATCO Power**"). The Genesee facility is located approximately 70 kilometres west of Edmonton, Alberta and is jointly owned by TransAlta and Capital Power. 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.

Fuel requirements for TransAlta's Western Canadian thermal power facilities are supplied by a surface strip coal mine located in close proximity to the facilities. TransAlta owns the Highvale mine that supplies coal to the Sundance and Keephills facilities. TransAlta estimates that the recoverable coal reserves contained in this mine are expected to be sufficient to supply the anticipated requirements for the life of the facilities which it serves, including running post PPA expiry and potential plant expansion. TransAlta also owns the Whitewood mine, which formerly supplied coal to the now decommissioned Wabamum facility. The Whitewood mine is no longer in operation.

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 Capital Power. 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 had originally proposed a 900 MW expansion at its Keephills facility. Although the Corporation received regulatory approval to proceed with the expansion, it subsequently made an application in

December 2004 to amend its 900 MW permit to allow for the construction of a smaller 450 MW facility using improved technology.

The Alberta Energy and Utilities Board ("**AEUB**") approved the amendment and on February 1, 2006, the Corporation entered into a development agreement with Capital Power, to jointly pursue the 450 MW Keephills 3 power project. On December 18, 2006, the Corporation assigned its rights in the development agreement 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 (a predecessor to Capital Power) and the parties have entered into a joint venture agreement governing the continued development of the Keephills 3 power project.

On February 26, 2007, construction of the net 450 MW Keephills 3 power project was commenced. The capital cost for the project, including mine capital, is expected to be approximately $1.9 billion and is expected to be completed at the end of the second quarter of 2011. Through K3LP, TransAlta and Capital Power are equal partners in the ownership of Keephills 3, with Capital Power responsible for construction and TransAlta responsible for managing the joint venture. Upon completion, it is expected that TransAlta will operate the facility and Capital Power and TransAlta will independently dispatch and market their share of the unit's electrical output. TransAlta will also provide coal to the facility through the Highvale mine.

Natural Gas-Fired Facilities

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

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Fort McMurray	AB	Poplar Creek	356	100	2001	2024
Fort Saskatchewan	AB	Fort Saskatchewan	118	30	1999	2019
Lloydminster	SK	Meridian	220	25	1999	2024
Total			**694**			

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 150 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 Corporation's interests in the Fort Saskatchewan and Meridian facilities are held through TA Cogen. See "TA Cogen" later in this AIF. The Fort Saskatchewan plant is located in Fort Saskatchewan, Alberta and is owned by TA Cogen and Strongwater Energy Ltd. The 118 MW Fort Saskatchewan natural gas-fired combined cycle cogeneration plant provides electricity and steam to Dow Chemical Canada Inc.

The Meridian plant is located in Lloydminster, Saskatchewan and is equally owned by TA Cogen and Husky Oil Operations Limited. This 220 MW cogeneration plant sells electricity to Saskatchewan Power Corporation, a Crown corporation owned by the Province of Saskatchewan. The steam produced by the Meridian Plant is sold to Husky Oil Limited to be utilized by its adjacent heavy oil upgrader.

On December 20, 2010, TA Cogen entered into an Asset Purchase Agreement to sell its 50 per cent ownership interest in the Meridian plant to Meridian Limited Partnership, an affiliate of Stanley Power Inc., the other limited partner to TA Cogen. The closing of the transaction, which is expected in early 2011, is subject to regulatory approval, the consent of Saskatchewan Power Corporation, the settlement of all matters of dispute between TA Cogen and Husky Oil Limited and its affiliates, and to the contemporaneous acquisition of Meridian Limited Partnership of the remaining 50 per cent interest in the Meridian facility from Husky Oil Limited. TA Cogen will provide transition support services to the purchaser for a period of six months following the closing.

Hydroelectric Facilities

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

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Akolkolex River System[3]	BC	Akolkolex	10	100	1995	2015
	BC	Pingston	45	50	2003, 2004	2023
Mamquam River System[3]	BC	Upper Mamquam	25	100	2005	2025
Thompson River System	BC	Bone Creek[2]	19	100	2011	2031
Bow River System	AB	Horseshoe	14	100	1911	2020
	AB	Kananaskis	19	100	1913, 1951	2020
	AB	Ghost	51	100	1929, 1954	2020
	AB	Cascade	36	100	1942, 1957	2020

	AB	Barrier	13	100	1947	2020
	AB	Bearspaw	17	100	1954	2020
	AB	Pocaterra	15	100	1955	2013
	AB	Interlakes	5	100	1955	2020
	AB	Spray	103	100	1951, 1960	2020
	AB	Three Sisters	3	100	1951	2020
	AB	Rundle	50	100	1951, 1960	2020
North Saskatchewan	AB	Brazeau	355	100	1965, 1967	2020
River System	AB	Bighorn	120	100	1972	2020
Oldman River System(3)	AB	Belly River	3	100	1991	-
	AB	Waterton	3	100	1992	-
	AB	St. Mary	2	100	1992	-
	AB	Taylor Hydro	13	50	2000	-
Total			**921**			

Notes:
(1) MW are rounded to the nearest whole number.
(2) Facility under construction reflects expected capacity and commissioning date.
(3) These facilities are EcoPower®registered.

The Corporation's Bow River and North Saskatchewan River System hydroelectric facilities are primarily peaking plants, meaning they are generally only operated during times of peak demand, and all output from these facilities is sold under one Alberta PPA.

Akolkolex River System

Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW located on the Akolkolex River, south of Revelstoke, British Columbia and is owned by the Corporation. It has been operating since 1995. The output from the facility is sold to BC Hydro.

Pingston is a run-of-river hydroelectric facility with installed capacity of 45 MW located on Pingston Creek, southwest of Revelstoke, British Columbia and down river of Akolkolex. The facility is equally owned by the Corporation and Brookfield Renewable Power Inc. and has been operating since 2003. The output from the facility is sold to BC Hydro.

Mamquam River System

Upper Mamquam is a run-of-river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver and is owned by the Corporation. It has been operating since 2005. The output from the facility is sold to BC Hydro.

Thompson River System

Bone Creek is a run-of-river hydroelectric facility currently under construction with expected capacity of 19 MW located on Bone Creek, north of Kamloops, near the town of Valemount, British Columbia and is owned by the Corporation. Bone Creek is expected to commence commercial operations in Q1 of 2011. The output from the facility is under contract with BC Hydro. The facility also qualifies for payments of $10/MWh until 2020 from Natural Resources Canada ("**NRCan**"), a division of the federal government, through the ecoEnergy for Renewable Power (" **eERP**") program.

Bow River System

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located in Seebe, Alberta. The plant is owned by the Corporation and has been operating since 1911. The output from the facility is under contract with BC Hydro.

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located in Seebe, Alberta. The plant is owned by the Corporation. The plant has been operating since 1913 and was expanded in 1951 and modified again in 1994. The facility operates under an Alberta PPA.

Ghost is a hydroelectric facility with installed capacity of 51 MW located on the Bow River in Cochrane, Alberta. The plant is owned by the Corporation and has been operating since 1929. The facility operates under an Alberta PPA.

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. The plant is owned by the Corporation and was purchased from the Government of Canada in 1941. The following year, TransAlta built a new dam and power plant to replace the original, the Corporation then added a second generating unit in 1957. The facility operates under an Alberta PPA.

Barrier is a run-of-river hydroelectric facility with installed capacity of 13 MW located in Seebe, Alberta. The plant is owned by the Corporation and has been operating since 1947. The facility operates under an Alberta PPA.

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. The plant is owned by the Corporation and has been operating since 1954. The facility operates under an Alberta PPA.

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located in Kananaskis, Alberta. The plant is owned by the Corporation and has been operating since 1955. The facility operates under an Alberta PPA.

Interlakes is a hydroelectric facility with installed capacity of 5 MW located in Kananaskis, Alberta. The plant is owned by the Corporation and

has been operating since 1955. The facility operates under an Alberta PPA.

Spray is a hydroelectric facility with installed capacity of 103 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. The plant is owned by the Corporation and has been operating since 1951. The facility operates under an Alberta PPA.

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. The plant is owned by the Corporation and has been operating since 1951. The facility operates under an Alberta PPA.

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir, which was created by the Canyon Dam to the south, and the Three Sisters dam to the north. The plant is owned by the Corporation and has been operating since 1951. The facility operates under an Alberta PPA.

North Saskatchewan River System

Brazeau is a hydroelectric facility with installed capacity of 355 MW located in Drayton Valley, Alberta. The plant is owned by the Corporation and has been operating since 1965. The facility operates under an Alberta PPA.

Bighorn is a hydroelectric facility with installed capacity of 120 MW located in Nordegg, Alberta. The plant is owned by the Corporation and has been operating since 1972. The facility operates under an Alberta PPA.

Oldman River System

Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in southern Alberta. Due to its location along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. Belly River has been operating since March 1991. Generation from the facility is sold in the Alberta spot market.

Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hillspring, southwest of Lethbridge, Alberta. Waterton has been operating since November 1992. Generation from the facility is sold in the Alberta spot market.

St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the St. Mary Dam on the Waterton Reservoir, near Magrath, in southern Alberta. St. Mary has been operating since December 1992. Generation from the facility is sold in the Alberta spot market.

Taylor consists of separate hydroelectric and wind facilities. The hydroelectric facility (" **Taylor Hydro**") is a run-of-river facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System which is owned by the Government of Alberta. Taylor Hydro has operated since May 2000, and is jointly owned by the Corporation along with Capital Power. Generation from the facility is sold in the Alberta spot market.

Wind Generation Facilities

The Corporation owns and operates approximately 1,064 MW of net wind generation capacity in twelve wind farms in western Canada, three in Ontario, one in Québec and two in New Brunswick.

Wind is not a dispatchable fuel, therefore in merchant markets, wind is not able to secure the annual average pool price. An assumption is made by TransAlta on the difference in revenue received for a generation forecast from a wind asset compared to a baseload asset. If these assumption and generation forecasts are correct, the corresponding revenue received may be reduced. Generation forecasts are based on the long-term production forecast from a site, which reflects the forty-year average climatic conditions for a site. Within one year there may be variation from this long-term average. In order to forecast the long-term average generation a number of factors which affect generation have to be assumed based on historic on-site data, such as, the blade icing, site access, wake and array losses and wind shear; the potential impact of topographical variations; and the electrical losses within the site. If these assumptions are incorrect there will be a long-term trend to under-generate, relative to the long-term forecast for the site.

As well as contracting for power, TransAlta enters into long-term and short-term contracts to sell the environmental attributes from our merchant wind and hydro facilities. These activities help to ensure earnings consistency from these assets. For 2011, TransAlta has sold approximately 76 per cent of the environmental attributes from our merchant wind facilities and 91 per cent of the environmental attributes from our merchant hydro facilities. Generally, for facilities under long-term contract, the benefit of the environmental attributes generated flow through to the contract holder.

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

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date

Fort Macleod	AB	McBride Lake	75	50	2003	2023
Fort Macleod	AB	Macleod Flats	3	100	2004	-
Fort Macleod	AB	Ardenville	69	100	2010	-
Pincher Creek	AB	Castle River	44	100	1997-2001	2011
Pincher Creek	AB	Summerview 1	70	100	2004	-
Fort Macleod	AB	Blue Trail	66	100	2009	-
Pincher Creek	AB	Summerview 2	66	100	2010	-
Pincher Creek	AB	Cowley Ridge	21	100	1993	-
Magrath	AB	Taylor Wind	3	100	2004	-
Pincher Creek	AB	Cowley North	20	100	2001	-
Pincher Creek	AB	Sinnott	7	100	2001	-
Fort Macleod	AB	Soderglen	71	50	2006	-
Total			**515**			

Note:
(1) MW are rounded to the nearest whole number. The capacity listed is for 100 per cent of the facility.

McBride Lake is a 75 MW wind farm 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 equally 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 LTC with ENMAX Energy Corp. ("**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. The Corporation also owns 100 per cent of the 0.7 MW McBride Lake East facility in the same vicinity.

Macleod Flats consists of a single Vestas V90-3.0 MW turbine and is located near Fort Macleod. It was commissioned in 2004 and was purchased by TransAlta in 2009.

On November 10, 2010, the 69 MW Ardenville wind farm began commercial operations. The wind farm is located in southern Alberta, near Fort Macleod. Ardenville is comprised of 23-3.0 MW Vestas V90 turbines and the output is sold in the Alberta spot market. The capital cost of the Ardenville project was approximately $135 million, which includes the purchase of an already operational 3.0 MW turbine at Macleod Flats.

Castle River is a 40 MW wind farm comprised of 59 Vestas V47-660 kW turbines and one Vestas V44-600 kW turbine located at Pincher Creek, Alberta. The facility is 71 per cent contracted primarily to 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 Cardston County and Hillspring areas of southwestern Alberta.

Summerview is a 68 MW wind farm comprised of 38-1.8MW turbines and is located approximately 15 kilometres northeast of Pincher Creek, Alberta. It was constructed by the Corporation and commenced commercial operations in 2004. The Summerview facility, 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.

Blue Trail is a 66 MW wind farm comprised of 22 Vestas V90-3.0 MW turbines located in southern Alberta which commenced commercial operations in November 2009. The total capital cost for this wind power project was $115 million. The capacity from this project is sold on the Alberta Power Pool. The Blue Trail wind farm is entitled to receive payments from NRCan, through the eERP program.

On February 23, 2010, the Corporation announced the commissioning of the 66 MW Summerview 2 wind generation facility in southern Alberta, located northeast of Pincher Creek. The facility consists of 22 Vestas V90-3.0 MW wind turbines. The total capital costs for this expansion of the Summerview 2 wind power project was $118 million. The capacity from this project is sold in the Alberta spot market. The Summerview 2 wind farm expansion receives payments from NRCan through the eERP program.

Cowley Ridge has total installed capacity of 21 MW and is located near the towns of Cowley and Pincher Creek, in southern Alberta. Cowley Ridge and Cowley expansion are 100 per cent owned by the Corporation, and are comprised of two parts: Cowley Ridge, which became operational in 1993, and the Cowley Expansion which became operational in 1994. Generation from this facility is sold in the Alberta spot market.

Taylor has total installed capacity of 3 MW and is located adjacent to Taylor Hydro. Taylor Wind began commercial operations in December 2004 and is owned by the Corporation. Generation from this facility is sold in the Alberta spot market.

Cowley North and Sinnott have a total installed capacity of 20 MW and 7 MW at Sinnot and are located adjacent to Cowley Ridge and directly east of Cowley Ridge, respectively. Cowley North and Sinnott began operations in the fall of 2001 and are 100 per cent owned by the Corporation. Generation from this facility is sold in the Alberta spot market.

Soderglen is a 71 MW facility located in southern Alberta, southwest of Fort Macleod and 40 kilometres from the Corporation's wind operations near Pincher Creek. This 71 MW facility is equally owned by the Corporation and Nexen Inc. The facility began commercial operations in September 2006. Generation from this facility is sold in the Alberta spot market.

Biomass Facilities

Grande Prairie is a biomass co-generation facility with an installed capacity of 25 MW and is located adjacent to Canadian Forest Products Ltd., in the city of Grande Prairie, in northern Alberta. The facility became commercially operational in 2005. Generation from this facility is sold to Canadian Forest Products Ltd., Alberta Infrastructure and the City of Grande Prairie.

Alberta PPAs

All of the Corporation's Alberta thermal and hydroelectric facilities, other than the Genesee 3, Belly River, Waterton, St. Mary and Taylor 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 those 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 operation and maintenance practices, and hedging activities.

The Corporation's hydroelectric facilities, other than Belly River, Waterton, St. Mary and Taylor Hydro, are contracted on an aggregated basis through one 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 of a ten-year Government of Canada Bond.

The pricing formula includes a provision for site restoration costs for the thermal generating plants during the term of the PPA. 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. The Corporation is evaluating the economics of running assets post PPA expiry. Upon the expiry of the PPAs, and subject to any legislative limitations, which are addressed below and the Corporation's ability to procure an extension to the operating licenses, if required, TransAlta will then be in a position to sell its electricity to the Alberta Power Pool and to third party purchasers through direct sales agreements.

The Alberta PPAs (together with legislation which applies thereto) permit the Balancing Pool, 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.

In June of 2010, the Government of Canada proposed a new regulation to deal with emissions from Canada's fleet of coal-fired power plants. Under Ottawa's proposal, at 45 years of age each coal-fired generating unit would have to meet a new emissions-performance standard or cease operations. The emissions standard for coal-fired facilities is expected to be equivalent to the emission performance of a combined-cycle natural gas power plant. If companies can deploy technology on their coal units to meet the new standard, then those units may operate beyond 45 years. However, if the units cannot physically meet the new emissions standard by their 45th year, then they would be required to cease operations.

TransAlta's position is that the transition to this new regulatory framework must be done in a careful and orderly fashion to maintain the critical reliability of our electricity infrastructure. This includes working closely with both the Governments of Canada and Alberta to address transition costs, the impacts on Alberta's PPAs, standards for emission requirements for natural gas facilities, and the mechanism for continued support of CCS as a lower-emitting generation technology.

Canada: Eastern Canada

Natural Gas-Fired Facilities

The Corporation's Ontario natural gas-fired generating facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Sarnia	ON	Sarnia	506	100	2003	2022-2025
Ottawa	ON	Ottawa	68	50	1992	2012
Mississauga	ON	Mississauga	108	50	1992	2017
Windsor	ON	Windsor	68	50	1996	2016
Total			**750**			

The Sarnia plant is a combined cycle cogeneration facility which is owned by the Corporation. The Corporation acquired 135 MW of existing

electric and steam generation capacity in 2002, and in March 2003 the Corporation completed construction and commissioning on a new 440 MW facility. In 2009, the Corporation decommissioned and removed a 69 MW natural gas turbine. The 506 MW Sarnia facility provides steam and electricity to nearby industrial

facilities owned by LANXESS (formerly Bayer Inc.), Nova Chemicals (Canada) Ltd. (which in turn supplies INEOS NOVA) and Suncor Energy Products Inc. On February 15, 2006, TransAlta announced that it had signed a five-year agreement with the OPA for generation from its Sarnia facility. Subsequently, the Ontario Minister of Energy and Infrastructure directed the OPA to seek contracts with TransAlta and certain other "Early Movers" to obtain terms and conditions which are more in keeping with those contracts it is offering to new facilities. In September 2009, TransAlta concluded a contract with the OPA, effective as of July 1, 2009 and terminating on December 31, 2025, which provides more favourable terms than those previously held by the facility. In addition, the new agreement brings the combined total term contracted with the OPA to 20 yea rs and includes provisions for the parties to share in the impact and benefit of changes in customer steam load or loss of steam customer.

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 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 re quire 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 2010, a new agreement was reached with the OEFC to make the plant fully dispatchable in order to sell the remaining capacity and ancillary services to the Ontario power market when it is economic to do so.

Hydroelectric Facilities

The Corporation's Ontario hydro-electric facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Montréal River System	ON	Ragged Chute	7	100	1991	2011
Wanapiki River System	ON	Moose Rapids	1	100	1997	2011
Mississippi River System	ON	Appleton	1	100	1994	2011
Mississippi River System	ON	Galetta	2	100	1998	2011
Misema River System	ON	Misema	3	100	2003	2027
Total			**14**			

Note:
(1) MW are rounded to the nearest whole number.

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of New Liskeard, in northern Ontario. Ragged Chute is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation Newenergy Canada, Inc. ("**Constellation**"). Ragged Chute has been operating since 1991.

Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapiki River, near Sudbury, in northern Ontario. Moose Rapids is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Moose Rapids has been operating since 1997.

Appleton is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Mississippi River, near Almonte, Ontario. Appleton is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Appleton has been operating since 1994.

Galetta is a run-of-river hydroelectric facility with installed capacity of 2 MW also located on the Mississippi River, near Galetta, Ontario. Galetta is 100 per cent owned by the Corporation. Galetta was originally built in 1907 and was retrofitted in 1998. Generation from this facility is sold to Constellation.

Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. Misema is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Misema has been operating since 2003.

Wind Generation Facilities

The Corporation's Ontario, Québec and New Brunswick wind generation facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) (1)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Melancthon Township	ON	Melancthon I	68	100	2006	2026
Melancthon and Amaranth Townships	ON	Melancthon II	132	100	2008	2028
Kingston	ON	Wolfe Island	198	100	2009	2029
Québec	QC	Le Nordais	99	100	1999	2033
Kent Hills	NB	Kent Hills	96	83	2008	2033
Kent Hills	NB	Kent Hills Expn.	54	83	2010	2035
Total			**647**			

Notes:
(1) MW are rounded to the nearest whole number.

Melancthon I has total installed capacity of 68 MW and is located in Melancthon Township near Shelburne, Ontario. Melancthon I became commercially operational on March 4, 2006. Generation from this facility is sold to the Ontario Power Authority (the "**OPA**").

Melancthon II is a 132 MW wind project located adjacent to Melancthon I, in Melancthon and Amaranth Townships. Melancthon II commenced commercial operations on November 24, 2008. Generation from this facility is sold to the OPA.

The Wolfe Island Wind Project is located on Wolfe Island, near Kingston, Ontario. This project's key components include 86-2.3 MW Siemens wind turbines, low voltage collector system and a high voltage transmission system, a 34.5-40 kV transformer station, and an operations and maintenance building. This facility is owned by the Corporation, and commenced commercial operation on June 26, 2009. Generation from this facility is sold to the OPA.

Le Nordais is located at two sites: Cap-Chat with 56.25 MW of installed capacity (75 turbines); and Matane with 42.75 MW of installed capacity (57 turbines). Le Nordais is on the Gaspé Peninsula of Québec. Le Nordais began commercial operations in 1999. Production from this facility is sold to Hydro-Québec.

Kent Hills is a 96 MW project comprised of 32-3.0 MW Vestas V90 turbines located in Kent Hills, New Brunswick, and delivers power under a 25 LTC with New Brunswick Power. Natural Forces Technologies Inc. ("**Natural Forces**"), an

Atlantic Canada based wind developer, is TransAlta's co-development partner in this project and Natural Forces exercised its option to purchase up to 17 per cent of the Kent Hills project in May 2009. Kent Hills has been commercially operational since 2008.

On November 21, 2010, the 54 MW Kent Hills expansion wind farm began commercial operations. The total capital cost for the project was approximately $100 million. Kent Hills expansion employs18-3.0 MW Vestas V90 turbines and the output is sold under a 25 year LTC with New Brunswick Power. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills expansion project subsequent to the commencement of commercial operations.

All of the electricity generated and sold by the Corporation's wind division and by the biomass facility, with the exception of Ardenville, Blue Trail, Macleod Flats, and Summerview 2 is generation from 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.

TA Cogen

The Corporation holds a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent ownership is held by Stanley Power Inc, a subsidiary of Cheung Kong Infrastructure Holdings Limited. TA Cogen holds interest in the 220 MW Meridian natural gas-fired generation facility in Saskatchewan, the 780 MW Sheerness thermal generation facility in Alberta, the 118 MW Fort Saskatchewan natural gas-fired cogeneration facility in Alberta, and the 108 MW Mississauga, the 68 MW Ottawa and 68 MW Windsor Essex facilities located in Ontario.

As noted earlier, on December 20, 2010, TA Cogen entered into an Asset Purchase Agreement to sell its 50 per cent ownership interest in the Meridian plant to Meridian Limited Partnership, an affiliate of Stanley Power Inc., the other limited partner to TA Cogen. The closing of the transaction, which is expected in early 2011, is subject to regulatory approval, the consent of Saskatchewan Power Corporation, the settlement of all matters of dispute between TA Cogen and Husky Oil Limited and its affiliates, and to the contemporaneous acquisition of Meridian Limited Partnership of the remaining 50 per cent interest in the Meridian facility from Husky Oil Limited. TA Cogen will provide transition support services to the purchaser for a period of six months following the closing.

United States

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

Location	State	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Centralia	WA	Centralia Coal No. 1	670	100	1971	-
		Centralia Coal No. 2	670	100	1971	-
		Centralia Natural gas	248	100	2002	-
		Skookumchuck	1	100	1970	2020
Saranac	NY	Saranac	240	37.5	1994	-
Imperial Valley	CA	Vulcan	34	50	1986	2016
		Del Ranch	38	50	1989	2018
		Elmore	38	50	1989	2018
		Leathers	38	50	1990	2019
		CE Turbo	10	50	2000	2029
		Salton Sea I	10	50	1987	2017
		Salton Sea II	20	50	1990	2020
		Salton Sea III	50	50	1989	2019
		Salton Sea IV	40	50	1996	2026
		Salton Sea V	49	50	2000	2020
Big Springs	TX	Power Resources	212	50	1988	-
Yuma	AZ	Yuma	50	50	1994	2024
Hilo	HI	Wailuku	10	50	1993	2023
Total			**2,428**			

Centralia

The Corporation owns a two unit 1,340 MW thermal facility and a 248 MW natural gas-fired facility in Centralia, Washington, located south of Seattle. The Corporation also owns a 1 MW hydroelectric generating facility on the Skookumchuck River near Centralia, and related assets which are used to provide water supply to TransAlta's other generation facilities in Centralia. On December 10, 2010, TransAlta entered into an agreement with Puget Sound Energy Inc. for Skookumchuck to provide power until 2020.

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.

TransAlta also owns a coal mine adjacent to the Centralia facility. 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.

During 2009, TransAlta wrote down the mining development costs incurred with respect to the Westfield project. These costs were carried from the shutdown of the Centralia mine as the Corporation continued to develop mining plans and longer term operation performance of Centralia Thermal. As a result of these plans being put on indefinite hold, these costs were written off.

CE Generation

TransAlta owns 50 per cent of CE Generation. 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 natural gas-fired cogeneration in New York State, Texas and Arizona.

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

CE Generation affiliates also 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 sold its output in 2009 under a tolling agreement, but has since moved to selling its output in the spot market. The New York facility operates an energy management agreement with a third party who is responsible for marketing the output from the facility and in return, the owners receive a fixed capacity payment and 80 per cent of dispatch revenue.

Wailuku

On February 17, 2006, a subsidiary of TransAlta, together with a subsidiary of MidAmerican Energy Holdings Company 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 natural 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.

Energy Trading Segment

The Energy Trading 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 energy markets which are the most attractive to enter, and developing strategies and plans to effectively compete in each market where the Corporation operates;
- Negotiating and entering into contractual agreements with customers for the sale of output from the Corporation's generation assets, including electricity, steam or other energy related commodities;
- Negotiating and managing fuel supply arrangements with third parties for the Corporation's generation assets;
- 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 periods of unplanned outages;
- Managing 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 Energy Trading 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 Energy Trading 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 the western U.S. The Corporation also owns and operates generating assets in British Columbia, Ontario, Québec, New Brunswick and Australia.

The Corporation expects electricity demand to grow as the current recession ends. In the long-term, most markets are expected to show growing demand for electricity; however, an increasing emphasis on efficiency may reduce future growth rates below historical levels. 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 most forms of renewable generation also involve intermittent or uncertain levels and timing of production, higher levels of renewable generation may be accompanied by greater capacity requirements. The Corporation believes that continued and growing demand for electricity, renewable portfolio standards, and the potential of increasing amounts of renewable generation to require additional capacity may provide an opport unity to increase its generation capacity.

Alberta is Canada's fourth largest province by population with approximately 3.72 million residents representing approximately 11 per cent of Canada's total population. Alberta consumed approximately 71,600 GWh of electricity in 2010. As at December 8, 2010, the aggregate installed capacity of generating facilities in Alberta was approximately 12,915 MW.

British Columbia is Canada's third largest province by population with approximately 4.53 million residents, representing approximately 13.3 per cent of Canada's total population. In 2007, British Columbia adopted "The BC Energy Plan" which sets to "develop realistic and achievable goals for conservation, energy efficiency and clean energy". Under the BC Energy Plan, British Columbia will be self-sufficient by 2016 with "insurance" power to supply increased demand levels.

Ontario is Canada's largest province with approximately 13.2 million residents representing approximately 38.7 per cent of Canada's total population. Ontario consumed approximately 142,400 GWh of electricity in 2009. Ontario Power Generation Inc., the successor to the generation business of Ontario's former integrated electric utility, controls two thirds of Ontario's approximately 34,557 MW of installed capacity, the balance of which is owned by municipal electric utilities and private independent power producers or industrial consumers.

Québec is Canada's second largest province by population with approximately 7.91 million residents, representing approximately 23.2 per cent of Canada's total population. The government in Québec has established the province's Energy Strategy which includes up to 4,500 MW of

additional hydroelectric capacity and 4,000 MW of wind capacity installed by 2015.

In New Brunswick, wholesale and industrial consumers are allowed to purchase power from either New Brunswick Power or a competing supplier. This 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.

Electrical utilities in the U.S. and Canadian 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 362,000 GWh of electricity was consumed in the NWPP in 2010. The WECC also reported an estimated aggregate electrical generating capacity of approximately 95,000 MW in the NWPP for the year ending December 31, 2010.

Australia is heavily dependent on coal for electricity, with over 80 per cent of the power produced derived from coal. Natural gas is increasingly used for electricity, especially in South Australia and Western Australia. 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 5,000 MW, while TransAlta's capacity in the region is approximately 300 MW. The Independent Market Operator of Western Australia estimates that there will be a 3.7 per cent annual growth in energy demand through 2020-21, and that capacity will grow to app roximately 5,500 MW by 2012-13. 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 – Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. The net revenue received under these contractual arrangements helps to minimize short-term revenue fluctuations due to the variable price of electricity.

Fuel diversity - The Corporation has a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, geothermal, wind and biomass. 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.

Energy Trading expertise - The Corporation believes that its Energy Trading 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 Highvale mine. Coal with lower sulphur content emits less sulphur dioxide when it is burned.

Wind Generation - The Corporation is the largest owner and operator of wind generation in Canada. Its 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:

	Sustaining Capital[(1)]	Growth Capital[(2)]	Total Capital Expenditures
2010	$308 million	$482 million	$790 million
2009	$380 million	$1,290 million	$1,670 million
2008	$465 million	$541 million	$1,006 million
2007	$371 million	$228 million	$599 million

2006	$207 million	$17 million	$224 million

Notes:

(1) Sustaining capital includes routine and productivity expenditures, mining equipment and land purchases, equipment modifications at Centralia, and planned maintenance.

(2) Growth capital consists primarily of expenditures for Keephills 3, the acquisition of Canadian Hydro, uprates and wind projects and for 2009 and 2010 includes joint venture contributions for the Keephills 3 dragline.

CORPORATE SEGMENT

Our Corporate Segment, which consists of 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 services, provides compliance, governance and support to our Generation and Energy Trading businesses.

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.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our business.

Canada

On June 23, 2010, the Government of Canada announced plans to regulate Greenhouse Gas (" **GHG**") emissions from the coal-fired power sector. The proposal, if passed into law, would become effective in 2015 and require existing coal-fired plants to meet a natural gas emissions performance standard by their 45th year of operation, or the end of their PPA term, whichever is later. If the plants subject to the regulation do not meet the required performance standard by that time, they would be required to cease operations. Until then, the plants would not be subject to any federal GHG compliance costs.

The Federal Government continues with the drafting of the above regulations, and has stated its intention to release draft regulations in April 2011. The draft regulations would then be subject to consultations with provinces, industry and the public. We are in discussions with both the Governments of Canada and Alberta about the design of the proposed regulation.

The above development would provide regulatory clarity for future capital decision-making. There are some issues that will have to be resolved, including how transition costs are recovered by generators, the impacts on PPAs, standards for

emission requirements for natural gas-fired facilities, and how CCS will continue to be supported. The effect of this proposal on the Alberta deregulated market and PPA structure must also be considered.

Additionally, work has continued on the development of a national Clean Air Management System (" **CAMS**") for air pollutants. Development work is being done through collective efforts of federal and provincial governments, industry, and environmental organizations, with the goal of constructing an acceptable national structure for managing pollutants such as sulphur dioxide ("**SO2**"), nitrogen oxide ("**NOx**") and particulates. Conceptually the system would establish baseline ambient air quality standards, industry emission standards, and mechanisms to address areas of non-compliance. It is expected that the CAMS model would default to provincial jurisdiction unless air quality problems remain unresolved. This process is expected to take several more years to complete. We are involved in the working groups and impact of CAMS on our operations, if implemented, is not evident at this time.

In Ontario, the provincial government continues to develop its plans for a GHG regulatory framework consistent with the Western Climate Initiative model, which uses a cap and trade design as the regulatory vehicle. Details of the Government of Ontario's proposed design have not yet been released.

In Alberta, mercury capture technology was installed by the end of the year and began operating at our coal-fired plants in order to achieve compliance with the Alberta requirement to reduce mercury emissions by 70 per cent by Jan. 1, 2011. To date performance of these units is meeting the mercury reductions required.

In British Columbia, the provincial government is in the process of developing regulations for emissions trading and an offsets system under the *Greenhouse Gas Reduction (Cap and Trade) Act*. The system would be compatible with the Western Climate Initiative Model (" **WCI**"). The WCI model is a cap and trade design being developed jointly with several Canadian provinces and U.S. states, including California, to establish similar reduction targets and a common emissions trading market. Consultations are underway regarding its design, with finalization of the regulations expected in 2011. Given TransAlta's low-carbon operations in B.C. this regulatory initiative is not expected to have any material impact on the company.

United States

In the U.S., the future direction on climate change has not been resolved. A variety of legislative proposals continue to be discussed, representing a mixture of energy-related and environmental legislation, though the dynamics and direction of the new Congress on this matter have yet to be clarified. Development of a cap and trade system for carbon is unlikely at this stage.

In the absence of legislative action, the administration is moving to regulate greenhouse gases under the *Clean Air Act*. Under the "tailoring rule" adopted in 2010, on July 1, 2011, the Environmental Protection Agency ("**EPA**") will require certain new plants, or major modifications to existing plants, to acquire permits for GHGs. After that point, new or modified plants that otherwise trigger major source preconstruction permit thresholds would be required to employ best available technology to reduce their GHG emissions. The EPA began implementing these rules on January 2, 2011. The definition of best available technology has not yet been determined. This EPA regulation is expected to face legal challenges as well as some opposition from Congress, and may be subject to further refinement in other rulemakings.

Further, at the end of December in 2010, the EPA stated its intentions to implement New Source Performance Standards for GHGs for power plants and refineries. They would cover emissions from both new and existing sources. The regulations are expected to be completed by the end of 2012, but the EPA does not expect existing sources would be affected until 2015 or 2016. These proposed regulations have not yet been developed so their impact is unclear. Again, this initiative is expected to face legal hurdles.

In Washington, we have been working with the State government to develop a plan to reduce GHG emissions from our Centralia plant, consistent with the Governor's Executive Order to reduce emissions by approximately 50 per cent of current levels by 2025. Discussions with the State and other stakeholders are ongoing.

TransAlta Activities

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 expect 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 the following elements:

Renewable Power

In addition to our acquisition of Canadian Hydro, our investment in renewable power sources continues through the building or expansion of renewable power resources such as the Summerview 2, Kent Hills, and Ardenville wind farms. An increased renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or in future offsets.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We have installed mercury control equipment at our Alberta Thermal operations in 2010 in order to meet the province's 70 per cent reduction objectives. Our new Keephills 3 plant will use supercritical combustion technology to maximize thermal efficiency, as well as SO2 capture and low NOx combustion technology.

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

Policy Participation

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 and industry participants to meet environmental requirements over the longer term.

CCS Development

On Oct. 14, 2009, the governments of Canada and Alberta announced that Project Pioneer, our CCS project, received committed funding of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding supports a FEED study that is expected to be completed in 2011. Once built, the prototype 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 be designed to capture one megatonne of carbon dioxide ("**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. Additionally, on Nov. 28, 2010, Project Pioneer was awarded $5AUD million from the Global Carbon Capture and Storage Institute to enhance knowledge transfer from the project both nationally and globally.

In addition, we look to advance other clean energy technologies through organizations such as the Canadian Clean Coal Power Coalition which examines emerging clean combustion technologies such as gasification. We are also part of a group of companies participating in the Integrated CO_2 Network to develop carbon capture and storage systems and infrastructure for Canada.

Offsets Portfolio

TransAlta maintains an offset portfolio with a variety of instruments than can be used for compliance purposes or otherwise banked or sold. We continue to examine additional 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.

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 price of electricity and availability of fuel supplies required to generate 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 strength of the economy, the available transmission capacity, the price of fuel that is used to generate 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 m aterial 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;
- global demand for energy products;
- the cost of carbon and other environmental concerns;
- weather-related disruptions affecting ability to deliver fuels or near-term demand for fuels;
- increases in the supply of energy products in the wholesale power markets;
- the extent of fuel transportation capacity or cost of fuel transportation service into the Corporation's markets; and
- the cost of mining that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

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 these 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 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, restricti ons, 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 ab ility 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 expe nditures cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs 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 and other wise 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, and mandatory GHG reporting requirements will be effective for 2010 in both Ontario and the United States. In both Canada and the U.S., GHG legislation or alternative forms of regulation are still under development, and it is too early to determine their impacts. 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 othe r air emission regulations may require the Corporation to incur costs that cannot be passed through to its customers under its 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 aspects 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 c ompanies 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 or because it is more economic to do so.

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 PPAs.

Under the government mandated Alberta PPAs pursuant to which the Corporation operates most of its thermal and hydroelectric 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 thermal 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 compensation for meeting the PPA obligations. 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 receive for its capacity 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. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities prior to occurrence or eliminate all adverse consequences in the event of failure. 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 Corp oration.

The Corporation has entered into ongoing 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 certain 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 could be adversely affected by natural disasters or other catastrophic events.

The Corporation's generation facilities and its operations are exposed to potential damage and partial or complete loss, resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures and other events beyond our control. The occurrence of a significant event which disrupts the ability of the generation facilities to produce or sell power for an extended period, including events which preclude existing customers from purchasing electricity, could have a material adverse effect on the Corporation. The Corporation's generation facilities could be exposed to effects of severe weather conditions, natural disasters and potentially catastrophic events such as a major accident or incident at the Corporation's sites. In certain cases, there is the potential that some events may not excuse the Corporation from performing its obligations pursuant to agreements with third parties. The fact that several of the Corporation's generation facilities are located in remote areas may make access for repair of damage difficult.

Equipment failure may have a material adverse effect on the Corporation.

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse affect on the Corporation. Although the Corporation's generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. In addition, there can be no assurance that any applicable insurance coverage would be adequate to protect the Corporation from material adverse effects.

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 or a failure

in the transmission system could impact the Corporation's ability to sell and deliver electricity, which could have a material adverse effect on the Corporation.

Variations in weather can affect demand for electricity and the Corporation's ability to generate electricity.

By the nature of the Corporation's business, the Corporation's earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect the Corporation's hydroelectric assets.

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

Hydroelectric, natural gas, biomass 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 jurisdictions where the Corporation operates. Any such change in regulations could have a material adverse effect on the Corporation.

Dam failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities.

The occurrence of dam failures at any of our hydroelectric facilities could result in a loss of generating capacity, and repairing such failures could require us to incur significant expenditures of capital and other resources. If such failures occur, we could be exposed to significant liability for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Upgrading all dams to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam failures could have a material adverse effect on the Corporation. We attempt to manage this risk b y following preventative maintenance procedures and obtaining insurance coverage, however, in the event of a sufficiently large dam failure, insurance coverage may not be adequate and we may suffer a material adverse effect.

Variation in wind levels may negatively impact the amount of electricity generated at the Corporation's wind facilities.

Wind is naturally variable. Therefore, the level of electricity production from our wind facilities will also be variable. In addition, the strength and consistency of the wind resource at our wind facilities may vary from what we anticipate due to a number of factors including: the extent to which our site-specific historic wind data and wind forecasts accurately reflects actual long-term wind speeds, strength and consistency; the potential impact of climatic factors; the accuracy of our assumptions relating to, among other things, weather, icing and soiling of wind turbines, site access, wake and line losses and wind shear; the potential impact of topographical variations; and the potential for electricity losses to occur before delivery.

A reduced amount of wind at the location of one or more of our wind facilities over an extended period may reduce the production from such facilities, as well as any environmental attributes that accrue to the Corporation and reduce our revenues and profitability.

Disruption in fuel supply from the forest products industry could negatively impact our biomass facility.

GPEC has its full electrical capacity committed to long-term contracts, which requires consistent wood waste deliveries for fuel. These fuel deliveries are in part supplied directly from the on-site customer, with the balance delivered by truck from other customer owned facilities. Loss of the on-site supply of wood waste may result in increased fuel expense in order to continue to meet all electrical supply obligations.

Trading risks may have a material adverse effect 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 medium-term and short-term basis. To the extent that the Corporation has long positions in the energy markets, a downturn in market prices will 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 market prices will 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 would 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 can be impacted by 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 conducted by the Corporation's independent Risk Management group to limit its exposure to risks arising from its trading activities, including value at risk, stop loss restrictions, stress testing, volumetric and term limits and restrictions on authorized instruments, the Corporation cannot guarantee that losses will not occur and such losses could have a material adverse effect on the Corporation.

The Corporation operates a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the United States and Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity and international conglomerates. Some competitors have significantly greater financial and other resources than we do. Competitive harm 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, there can be no assurance that these risk management efforts will be effective and 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 Corp oration's counterparties and accordingly increase the amount of collateral the Corporation may have to provide, which could have a material adverse effect on the Corporation.

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 eff ect on the Corporation.

Insurance coverage may not be sufficient.

The Corporation has insurance for its facilities, including all risk property insurance, commercial general liability insurance and, boiler and machinery coverage in amounts and with deductibles that the Corporation considers appropriate. The Corporation also carries replacement power and business interruption insurance for certain of its

facilities where it does not otherwise have contractual arrangements to address these potential losses or where in other cases it would not be economic to do so.

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 or 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 material compliance with all applicable tax interpretations, regulations, and legislation, the Corporation cannot guarantee that it will not have disagreements with taxation authorities with respect to the Corporation's tax filings that could have a material adverse effect on the Corporation.

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 and as a party in commercial disputes which are resolved by arbitration. There can be no assurance that the Corporation will be successful in the defence 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 satisfactory 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. The Corporation expects to re-negotiate three collective bargaining agreements, involving 551 of its employees, in 2011 and an additional three collective bargaining agreements, involving 267 of its employees, in 2012. 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.

Risks relating to TransAlta's development projects and acquisitions may materially adversely affect the Corporation

Development projects and acquisitions undertaken by the Corporation may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third party opposition, cost escalations, construction delays, shortages of raw materials or skilled labour and capital constraints. The occurrences of these risks could have a material adverse impact on TransAlta's business, financial condition, results of operations and cash flows.

Expansion of TransAlta's business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development projects could have a material adverse impact on TransAlta's business, financial condition, results of operations and cash flows. Further, TransAlta cannot make assurances that it will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

With respect to acquisitions, TransAlta cannot make assurances that it will identify suitable transactions or that it will have access to sufficient resources, through its credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition the Corporation proposes or completes would be subject to normal commercial risks that the transaction may not be completed on the terms negotiated, on time, or at all. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on the Corporation's business, financial condition, results of operations and cash flows.

EMPLOYEES

As of December 31, 2010, the Corporation had 2,389 active employees, which comprises full-time, part-time and temporary employees, of which 1,650 were employed in TransAlta's generation business and 66 were employed in TransAlta's energy trading 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 2010, the Corporation renewed seven of the agreements; an additional three agreements are expected to be re-negotiated in 2011.

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 February 23, 2011, there were 221,187,779 common shares outstanding and 12,000,000 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, 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 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 at the rate established by the Board 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 distribute d 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 Board 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 $25.00 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 then consists of less than 16 directors, or three directors if the Board 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 shareh olders 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.

Series A Shares

The only outstanding preferred shares are the rate reset shares issued on December 10, 2010 with a coupon of 4.60% (" **Series A Shares**"), as discussed in the section entitled General Development of the Business. Certain provisions of the Series A Shares are discussed below.

Dividends on Series A Shares

The holders of Series A Shares will be entitled to receive, as and when declared by the Board out of moneys of the Corporation properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax required to be deducted and withheld by the Corporation).

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period", as defined herein), the holders of Series A Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate (as defined herein) for such Subsequent Fixed Rate Period by $25.00 (less any tax required to be deducted and withheld by the Corporation). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by the Corporation on the Fixed Rate Calculation Date (as defined herein) and will be equal to the sum of the Government of Canada Yield (as defined herein) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares and the Series B Shares described below, and will remain unchanged over the life of the Series A Shares.

Redemption of Series A Shares

The Series A Shares shall not be redeemable prior to March 31, 2016. The Series A Shares are redeemable by TransAlta in whole or in part on or after March 31, 2016, and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax required to be deducted and withheld by the Corporation).

If the Corporation gives notice to the holders of the Series A Shares of the redemption of all of the Series A Shares, the right of a holder of Series A Shares to convert such Series A Shares shall terminate and the Corporation shall not be required to give notice to the registered holders of the Series A Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series A Shares.

Conversion of Series A Shares into Series B Shares

The holders of the Series A Shares will have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, series B of the Corporation (the "**Series B Shares**"), subject to certain conditions, on

March 31, 2016 and on March 31 in every fifth year thereafter. The holders of the Series B Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "**Quarterly Floating Rate Period**"), in the amount per share determined by multiplying the "**Floating Quarterly Dividend Rate**" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 2.03 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the nume rator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax required to be deducted and withheld by the Corporation). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 2.03 per cent.

The Series A Shares and Series B Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series A Shares and Series B Shares are identical in all material respects.

Modification

The provisions attaching to the Series A Shares as a class may be amended with the written approval of all the holders of Series A Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Dividend Reinvestment and Share Purchase Plan

TransAlta has a Dividend Reinvestment and Share Purchase Plan which permits common shareholders of TransAlta to elect to reinvest their cash dividends in additional Common Shares of TransAlta. These Common Shares may be provided to the participants at a discount of up to five per cent to the weighted average market price traded on the Toronto Stock Exchange ("**TSX**") during the last five trading days preceding the relevant dividend payment dates. The discount was set at three per cent commencing with the dividend payable in July 1, 2010. Participants may also make additional cash payments of up to $5,000 per quarter to purchase additional Common Shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the Dividend Reinvestment and Share Purchase Plan.

CREDIT RATINGS

Issuer Rating

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in certain collateralized business activities on a cost effective basis depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require the Company to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

As of December 31, 2010, the Corporation's corporate credit rating from S&P was BBB (stable), its senior unsecured debt rating from Moody's was Baa2 (negative outlook), and its issuer rating from DBRS was BBB (stable).

Senior Unsecured Long-Term Debt

As of December 31, 2010, the Corporation's senior unsecured long-term debt is rated BBB (stable) by DBRS, BBB (stable) by S&P and Baa2 (negative outlook) 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.

The Moody's rating system provides that 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.

Series A Shares

The Series A Shares have been rated Pfd-3 (stable) by DBRS and P-3(high) (stable) by S&P. The ratings for preferred shares range from a high of Pfd-1 to a low of D for DBRS and from a high of P-1 to a low of C for S&P.

According to the DBRS rating system, securities rated Pfd-3 are of adequate credit quality. "High" or "low" grades are used to indicate the relative standing within a rating category.

According to the S&P rating system, securities rated P-3 are less vulnerable to non payment than other speculative issues. The ratings from P-1 to -3 may be modified by "high", "mid" and "low" grades which indicate relative standing within the major rating categories.

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

Common Shares

In setting dividends, the Board 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 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
2008	First Quarter	$0.27
	Second Quarter	$0.27
	Third Quarter	$0.27
	Fourth Quarter	$0.27
2009	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29
2010	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29

On December 7, 2010, the Board declared a cash dividend of $0.29 per common share, payable on April 1, 2011 to shareholders of record on March 1, 2011.

Series A Shares

On December 13, 2010, the Board approved an initial dividend of $0.3497 per share on TransAlta's issued and outstanding Series A Shares for the period from December 10, 2010 to March 31, 2011. The dividend is payable on March 31, 2011 to shareholders of record on March 1, 2011.

MARKET FOR SECURITIES

Common Shares

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:

Month	Price ($) High	Low	Volume
2010			
January	23.98	22.06	12,926,828
February	24.00	21.62	10,623,554
March	23.35	22.00	19,248,855
April	22.93	20.54	17,663,924
May	21.09	19.55	16,062,435
June	21.67	19.60	17,881,262
July	21.12	19.70	9,290,865
August	21.50	20.26	14,098,678
September	22.05	21.20	16,199,764
October	22.24	20.31	11,286,417
November	21.61	20.12	16,691,928
December	21.71	20.81	16,897,528
2011			
January	22.08	20.60	10,328,775
February 1 to 23	21.25	20.57	12,720,649

Series A Shares

TransAlta's Series A Shares are listed on the TSX under the symbol "TA.PR.D".

Date(s) of Issuance	Number of Common Shares or Securities	Issue Price per Security	Description of Transaction
December 10, 2010(1)	12,000,000 Series A Shares	$25.00	Public Offering

Note:
(1) Preferred Shares were issued pursuant to the Corporation's public offering of Series A Shares pursuant to a prospectus supplement dated October 19, 2009. See "General Development of the Business –Year Ended December 31, 2010".

Month	Price($) High	Low	Volume
2010			
December 10 – 31	26.00	24.75	1,257,242
2011			
January	25.55	25.00	494,424
February 1 to 23	25.45	25.00	204,880

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of the directors and officers of TransAlta as at February 22, 2011, 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(1)	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 of 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., Sun Life Financial Inc. and Chair of the Board of Nordion Inc. (formerly 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 the Chair of the Audit and Risk Committee of the Board. Mr. Anderson holds a bachelor in business administration from the University of Western Ontario (London, ON) and is a Chartered Accountant.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Stephen L. Baum New Hampshire, U.S.A.	2008	***Corporate Director***. Mr. Baum was Chairman and CEO of Sempra Energy from July 2000 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, COO and Vice-Chairman of Sempra Energy, from July 1998 to July 2000. 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 U tilities, 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 Sciences Corporation and is a member of its Audit Committee and Governance Committee. At TransAlta, Mr. Baum is a member of 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.
Timothy W. Faithfull England, U.K.	2003	***Corporate Director***. Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc (energy), where he held 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, Canadian Natural Resources Limited, Shell Pension Trust Limited and AMEC plc, where he is the senior independent director. He is a past director of Enerflex Systems Income Fund. At TransAlta, Mr. Faithfull is the Chair of the Human Resources Committee of the Board. Mr. Faithfull holds a master of arts in philosophy, politics and economics from the University of Oxford, UK.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Amb. Gordon D. Giffin[2] Georgia, U.S.A.	2002	***Lawyer and Senior Partner, McKenna, Long & Aldridge LLP*** (law firm). From 1997 to 2001, Mr. Giffin served as the United States Ambassador to Canada with responsibility for managing Canada/US 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, DC. 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 speciali zed 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 Just Energy Group Inc. At TransAlta, Mr. Giffin is the 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).
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 Orion Oil & Gas Ltd. and a director of Axia NetMedia Corporation, CanElson Drilling Inc., Rodinia Oil Corp. and Elson Energy Enterprises Ltd. At TransAlta, Mr. Jespersen is a member of the Audit and Risk 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).

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation

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 g rown to a present day market capitalization of approximately $4.5 billion. Mr. Kanovsky currently is a director of Argosy Energy Inc., ARC Resources Ltd., Bonavista Energy Corporation, Devon Energy Corporation and Pure Technologies Ltd. Mr. Kanovsky intends to reduce these public directorships from five to four effective 2011. At TransAlta, Mr. Kanovsky is a member of the Governance and Environment Committee and the Human Resources 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 (law firm). 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. She has also served on the boards of Southam Inc., Provigo Inc., Bell Canada International Inc., Bell Globemedia Inc., the Public Sector Pension Investment Board, the Hudson's Bay Company and UPM-Kymmene Corporation. She also currently serves on the boards of BCE Inc. and Bell Canada. She is also a director of The Historica-Dominion Institute, a private-sector education initiative to promote knowledge of Canadian history and heritage, 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 and in 2009 she was appointed a member of the Prime Minister's Advisory Committee on the Public Service of Canada. At TransAlta, Mrs. Kaufman is the Chair of the Board. Mrs. Kaufman holds a bachelor of civil law from McGill University (Montréal, QC) and a master of laws from the Université de Montréal (Montréal, QC).

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Gordon S. Lackenbauer[3] 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 Energy Corporation and Chair of its Audit Committee and a member of both the Corporate Governance and Reserves Committees. He is also a director of CTV Globemedia Inc. At TransAlta, Mr. Lackenbauer is a member of the Audit and Risk Committee and the Governance and Environment 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.

Karen E. Maidment Ontario, Canada	2010	***Corporate Director***. Ms. Maidment was Chief Financial and Administrative Officer ("**CFAO**") of BMO Financial Group ("**BMO**") from 2007 to 2009. Prior to that she was Senior Executive Vice-President and Chief Financial Officer ("**CFO**") from 2003 to 2007 and Executive Vice-President and CFO from 2000 to 2003 of BMO. As CFAO of BMO, she was responsible for all global finance operations, risk management, legal and compliance, communications and mergers and acquisitions. Prior to that, Ms. Maidment held several executive positions with Clarica Life Insurance Company ("**Clarica**") from 1988 to 2000, including CFO. Ms. Maidment was CFO when Clarica was the first demutualization of an insurance company in Ca nada with an initial public offering of $950 million. She also led the insurance industry group, working with government, to develop regulations and framework to convert Canada's major insurers from mutual to public companies. Ms. Maidment is a past director of Harris Bank, BMO Nesbitt Burns, where she was also Chair of the Audit Committee, Bank of Montreal Pension Fund, Mutual Trustco, MCAP Financial and The Mutual Group (US). She currently serves on the Board of T D Ameritrade Holding Corporation and is a member of both the Audit and Risk Committees, and a member of the Princess Margaret Hospital Foundation Board. At TransAlta, Ms. Maidment is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board. Ms. Maidment holds a bachelor of commerce from McMaster University (Hamilton, ON), is a Chartered Accountant and in 2000 she was named Fellow of the Institute of Chartered Accountants of Ontario.

Name, Province (State) and Country of Residence[(1)]	Year first became Director	Principal Occupation
Dr. Martha C. Piper British Columbia, Canada	2006	***Corporate Director***. Dr. Piper was President and Vice-Chancellor of the University of British Columbia ("**UBC**") 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 served as Chair of 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 Governance and Environment Committee and the Human Resources 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 18 international universities. Dr. Piper is an Officer of the Order of Canada and a recipient of the Order of British Columbia.

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 Intact Financial Corporation and co-chair of the Calgary Stampede Foundation Campaign. He is a past Director of the Canadian Imperial Bank of Commerce. He is past Chair of the Calgary Stampede Foundation, the Alberta Secretariat for Action on Homelessness, the Calgary Committee to End Homelessness, the Canada-Alberta ecoEnergy Carbon Capture & Storage Task Force, the Conference Board of Canada, the Calgary Zoological Society, the Canadian Electrical Association, the United Way Campaign of Calgary and Area, and the Calgary Zoo's "Destination Africa" capital 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, the Conference Board Honorary Associate Award for 2008, the Chamber of Commerce Sherrold Moore Award of Excellence for 2009 and received the Canadian Energy Person of the Year Award for 2010 from the Energy Council of Canada.

Notes:

(1) The following nominee directors are Canadian residents: William D. Anderson, C. Kent Jespersen, Michael M. Kanovsky, Donna Soble Kaufman, Gordon S. Lackenbauer, Karen E. Maidment, Martha C. Piper and Stephen G. Snyder.

(2) Ambassador Giffin was a director of AbitibiBowater Inc. ("**Abitibi**") from October 29, 2007 until his resignation on January 22, 2009. In April 2009, Abitibi and certain of its U.S. and Canadian subsidiaries filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware for relief under the provisions of Chapter 11 and Chapter 15 of the United States Bankruptcy Code, as amended, and sought creditor protection under the CCAA with the Superior Court of Quebec in Canada. On September 14, 2010, Abitibi announced that it had received approval for its plan of reorganization from unsecured creditors under the CCAA in Canada. On September 21, 2010, Abitibi announced it had received the necessary creditor approval for its plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code. On September 23 , 2010, Abitibi announced that the Quebec Superior Court rendered an order sanctioning the plan of reorganization under the CCAA. On November 22, 2010, Abitibi announced that the U.S. Bankruptcy Court for the District of Delaware issued an opinion confirming the plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code. On December 9, 2010, Abitibi announced that it had successfully completed its reorganization and emerged from creditor protection under the CCAA in Canada and Chapter 11 of the U.S. Bankruptcy Code.

(3) 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 St ates.

Officers

Name	Principal Occupation	Residence
Stephen G. Snyder	President and Chief Executive Officer	Alberta, Canada
Dawn L. Farrell	Chief Operating Officer	Alberta, Canada
Brett Gellner	Chief Financial Officer	Alberta, Canada
Kenneth S. Stickland	Chief Legal Officer	Alberta, Canada
Michael Williams	Chief Administration Officer	Alberta, Canada
William D. A. Bridge	Chief Technology Officer	Alberta, Canada
Hume D. Kyle	Vice-President, Controller and Treasurer	Alberta, Canada
Maryse C. St.-Laurent	Vice-President and 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 April 2009, Dawn Farrell was Executive Vice-President, Commercial Operations and Development of the Corporation. Prior to July 2007, she was Executive Vice-President Engineering, Aboriginal Relations and Generation at BC Hydro and prior to June 2006 she was Executive Vice-President Generation.

- Prior to June 2010, Brett Gellner was Vice-President, Commercial Operations of the Corporation. Prior to July 2008, he was Co-Head and Managing Director, Investment Banking at CIBC World Markets Inc.

- Mr. Kenneth Stickland has held the same principal occupation for the past five years, though his title has changed over the course of this period of time.

- Mr. Michael Williams has held the same principal occupation for the past five years, with the exception that in July 2007 he was given added responsibility for Information Technology and in November 2010 this responsibility was assigned to the Chief Operating Officer.

- Prior to April 2009, William Bridge was Executive Vice-President, Generation Technology and PMM of the Corporation. Prior to July 2007, he 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 and Development, Eastern Canada.

- Prior to December 2010, Hume Kyle was Vice-President, Finance and Controller of the Corporation. Prior to February 2009, he was Vice-President, Finance and Chief Financial Officer of Fort Chicago Energy Management Ltd.

- Ms. Maryse St.-Laurent has held the same principal occupation for the past five years.

As of February 23, 2011, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over an aggregate of 666,722 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 ten 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 2011 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, 2010, there has been no indebtedness outstanding to TransAlta from any of TransAlta's 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 ten 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:

(i) 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

(ii) 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 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 member of the Board 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 26 and 28 of the Corporation's audited consolidated financial statements for the year ended December 31, 2010 which financial statements are incorporated by reference herei n. See "Documents Incorporated by Reference" herein.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for TransAlta's common shares and TransAlta's First Preferred Shares Series A is CIBC Mellon Trust Company in Vancouver, Calgary, Winnipeg, Toronto and Montréal. 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 – 2 nd 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 to TransAlta's Investor Relations department.

Additional financial information is provided in TransAlta's audited consolidated financial statements as at and for the year ended December 31, 2010 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 five independent members, William D. Anderson (Chair), C. Kent Jespersen, Karen E. Maidment, 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, Mr. Gordon S. Lackenbauer and Ms. Karen E. Maidment 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 w ith 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, with 17 years experience with a major Chartered Accountant firm in Canada. Mr. Anderson has served as CEO of a public company and as CFO 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 chair and member of several public companies. He has served on the board and audit committee of a public company that reports under U.S. GAAP.
C. Kent Jespersen	Mr. Jespersen has held several senior management positions and is a director and Chief Executive Officer of several public companies including being the Chair of Axia Net Media's audit committee. Mr. Jespersen has experience supervising individuals who have experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues raised by TransAlta's financial statements.
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 master of business administration from the University of Western Ontario and is a Chartered Financial Analyst.
Karen E. Maidment	Ms. Maiment is a Chartered Accountant. Ms. Maidment has served as a Chief Financial Officer with financial oversight responsibilities for TSX and NYSE listed public companies for over 15 years. She has also held positions where she was responsible for global finance operations, risk management, legal and compliance, communications and mergers and acquisitions. In addition, Ms. Maidment has worked with government bodies in order to develop regulations and frameworks for the conversion of major insurers from mutual to public companies. Ms. Maidment holds a bachelor of commerce from McMaster University, and in 2000 was named a Fellow of the Institute of Chartered Accountants of Ontario.
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, 2010 are:

Governance and Environment Committee	Human Resources Committee
Chair: Ambassador Gordon D. Giffin	**Chair: Timothy W. Faithfull**
Michael M. Kanovsky	Stephen L. Baum
Gordon S. Lackenbauer	C. Kent Jespersen
Karen E. Maidment	Michael M. Kanovsky
Dr. Martha C. Piper	Dr. Martha C. Piper
Donna Soble Kaufman (ex officio)	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, 2010 and December 31, 2009, Ernst & Young LLP and its affiliates were paid $3,499,254 and $3,562,032 respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31		**2010**		**2009**
Audit Fees	$	2,737,081	$	2,679,080
Audit-related fees		729,873		824,631
Tax fees		32,300		58,321
Total	**$**	**3,499,254**	**$**	**3,562,032**

No other audit firms provided audit services in 2010 or 2009.

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 2010 include payments related to 2009 in the amount of $969,568. Total audit fees for 2009 include payments related to 2008 in the amount of $1,212,080.

Audit-Related Fees

The audit-related fees in 2010 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, other audits, public equity and debt offerings, and miscellaneous accounting advice provided to the Corporation. The audit-related fees in 2009 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, public equity and debt offerings and miscellaneous advice provided to the Corporation.

Tax Fees

The majority of tax fees for each of 2009 and 2010 relate to various tax related matters in our foreign operations.

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 (the "**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. The Policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting. In 2009 the ARC granted management the authority to approve *de minimus* permissible non-audit services (which are in the aggregate the lesser of five per cent of the total fees paid to the external aud itors or $125,000) provided such services are reported to the ARC at its next scheduled meeting.

APPENDIX "A" – 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 Sarban es-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 Governance and Environment 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 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 two members may call a special meeting of the Committee at any time. Although

the Corporation's Chief Executive Officer ("the CEO') 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. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls established by management, iii) the risk identification assessment conducted by management and the programs established by management in response to such assessment, iv) the internal audit function v) compliance with accounting and finance based legal and regulatory requirements, vi) the external auditors' qualifications, independence and performance. 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 the 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 to comply 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. Audit and Financial Matters

A) External Auditors' Qualifications

(a) The Committee shall 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) r ecommending 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) 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;

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

(viii) 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;

B) Independent Audit Process

(a) Subject to the delegation granted to the Chair of the Committee, 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;

(b) Review with management and the 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; the "Management's Discussion and Analysis" and any required reconciliation;

(ii) review any report or opinion to be rendered in connection therewith and report to the Board as required;

(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 are not a regular 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", US GAAP Note, the related earnings release, and approve their release to the public as required;

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

(f) 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 may be or have been disclosed in the financial statements;

(g) 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 Corporation's internal controls was reported to the Committ ee;

C) Financial Planning

(h) Review and recommend to the Board for approval the Corporation's issuance and redemption of securities (including the review of all public filings to effect any of the issuances or redemptions), financial commitments and limits, and any material changes underlying any of these commitments;

(i) Review annually the Corporation's annual tax plan;

2. Governance

(j) 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 prior to dissemination to the public;

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

(l) Review quarterly with senior management and 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;

(m) 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 Corporation's financial statements;

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

(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) Review annually the Insider Trading policy and approve changes as required;

(r) Together with the Human Resources Committee of the Board, review annually, and as required, the overall governance of the Corporation's Pension Plans, approving the broad objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon to the Board annually;

(s) Review the annual audit of expense accounts and perquisites of the Directors, the CEO and his direct reports and their use of Corporate assets;

(t) Review annually 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 disclosure made to the Committee by the CEO, CFO 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;

(w) 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;

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

(y) 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;

(z) 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;

(aa) Report annually to shareholders on the work of the Committee during the year;

3. Internal Audit

(bb) 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;

(cc) 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. The Committee shall also 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;

(dd) Meet separately with management, the external auditors and internal auditors to review issues and matters of concern

respecting audits and financial reporting;

(ee) 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;

(e) Recommend to the Human Resources Committee the appointment, termination or transfer of the Vice-President, Internal Audit.

4. Risk Management

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 to take 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 the Corporation's 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 potential 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 the Corporation is exposed to;

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

(iv) the overall effectiveness of the enterprise risk management process.

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 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 ongoing 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 then 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;

"**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.

TransAlta™

TransAlta Management's Discussion and Analysis

December 31, 2010

Plant Summary

As of January. 31, 2011	Facility	Capacity (MW) [1]	Ownership (%)	Net capacity ownership interest (MW) [1]	Fuel	Revenue source	Contract expiry date
Western Canada 42 Facilities	Sundance, AB [2]	2,141	100	2,141	Coal	Alberta PPA / Merchant [3]	2017, 2020
	Keephills, AB [4]	812	100	812	Coal	Alberta PPA / Merchant [4]	2020
	Keephills 3, AB [5]	450	50	225	Coal	Merchant	-
	Genesee 3, AB	450	50	225	Coal	Merchant	-
	Sheerness, AB	780	25	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100	356	Gas	LTC/Merchant	2024
	Fort Saskatchewan, AB	118	30	35	Gas	LTC	2019
	Meridian, SK	220	25	55	Gas	LTC	2024
	Brazeau, AB	355	100	355	Hydro	Alberta PPA	2020
	Big Horn, AB	120	100	120	Hydro	Alberta PPA	2020
	Spray, AB	103	100	103	Hydro	Alberta PPA	2020
	Ghost, AB	51	100	51	Hydro	Alberta PPA	2020
	Rundle, AB	50	100	50	Hydro	Alberta PPA	2020
	Cascade, AB	36	100	36	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100	19	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100	17	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100	15	Hydro	Alberta PPA	2013
	Horseshoe, AB	14	100	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100	13	Hydro	Alberta PPA	2020
	Taylor Hydro, AB	13	50	6	Hydro	Merchant	-
	Interlakes, AB	5	100	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100	3	Hydro	Merchant	-
	Three Sisters, AB	3	100	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100	3	Hydro	Merchant	-
	St. Mary, AB	2	100	2	Hydro	Merchant	-
	Upper Mamquam, BC	25	100	25	Hydro	LTC	2025
	Pingston, BC	45	50	23	Hydro	LTC	2023
	Bone Creek, BC [5]	19	100	19	Hydro	LTC	2031
	Akolkolex, BC	10	100	10	Hydro	LTC	2015
	Summerview 1, AB	70	100	70	Wind	Merchant	-
	Summerview 2, AB	66	100	66	Wind	Merchant	-
	Ardenville, AB	69	100	69	Wind	Merchant	-
	Blue Trail, AB	66	100	66	Wind	Merchant	-
	Castle River, AB[6]	44	100	44	Wind	LTC/Merchant	2011
	McBride Lake, AB	75	50	38	Wind	LTC	2023
	Soderglen, AB	71	50	35	Wind	Merchant	-
	Cowley Ridge, AB	21	100	21	Wind	Merchant	-
	Cowley North, AB	20	100	20	Wind	Merchant	-
	Sinnott, AB	7	100	7	Wind	Merchant	-
	Macleod Flats, AB	3	100	3	Wind	Merchant	-
	Taylor Wind, AB	3	100	3	Wind	Merchant	-
	Grande Prairie, AB	25	100	25	Biomass	LTC	2019-2024
	Total Western Canada	**6,788**		**5,403**			
Eastern Canada 13 Facilities	Sarnia, ON [7]	506	100	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50	54	Gas	LTC	2017
	Ottawa, ON	68	50	34	Gas	LTC	2012
	Windsor, ON	68	50	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100	7	Hydro	LTC	2011
	Misema, ON	3	100	3	Hydro	LTC	2027
	Galetta, ON	2	100	2	Hydro	LTC	2011
	Appleton, ON	1	100	1	Hydro	LTC	2011
	Moose Rapids, ON	1	100	1	Hydro	LTC	2011
	Wolfe Island, ON	198	100	198	Wind	LTC	2029
	Melancthon, ON	200	100	200	Wind	LTC	2026-2028
	Le Nordais, QC	99	100	99	Wind	LTC	2033
	Kent Hills, NB [8]	150	83	125	Wind	LTC	2033-2035
	Total Eastern Canada	**1,411**		**1,264**			
United States 17 Facilities	Centralia, WA [9]	1,340	100	1,340	Coal	Merchant	-
	Centralia Gas, WA	248	100	248	Gas	Merchant	-
	Power Resources, TX	212	50	106	Gas	Merchant	-
	Saranac, NY	240	37.5	90	Gas	Merchant	-
	Yuma, AZ	50	50	25	Gas	LTC	2024
	Imperial Valley, CA [10]	327	50	164	Geothermal	LTC	2016-2029
	Skookumchuck, WA	1	100	1	Hydro	LTC	2020
	Wailuku, HI	10	50	5	Hydro	LTC	2023
	Total U.S.	**2,428**		**1,979**			
Australia 5 Facilities	Parkeston, WA	110	50	55	Gas	LTC	2016
	Southern Cross, WA [11]	245	100	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			

TOTAL	**10,982**	**8,946**

1 Megawatts are rounded to the nearest whole number
2 Includes a 15 MW uprate on unit 3 expected to be commercial in 2012
3 Merchant capacity refers to uprates on unit 4 (53 MW), unit 5 (53 MW), and unit 6 (44 MW)
4 Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2012 as merchant capacity
5 Facilities currently under development
6 Includes seven individual turbines at other locations
7 Sarnia's net maximum capacity (NMC) has been adjusted from 575 MW due to decommissioning of equipment at the facility
8 Includes Kent Hills 54 MW expansion that was completed in Q4 2010
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 four facilities

For more information on TransAlta's facilities, please visit **www.transalta.com/facilities**

Management's Discussion and Analysis

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited 2010 consolidated financial statements. Our consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian 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 Feb. 23, 2011. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including our Annual Information Form, is available on SEDAR at **www.sedar.com** and on our website at **www.transalta.com.**

Business Environment

Overview of the Business

We are a wholesale power generator and marketer with operations in Canada, the United States ("U.S."), and Australia. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and utilize a broad range of generation fuels including coal, natural gas, hydro, wind, geothermal, and biomass. During 2010, we began commercial operations at our Summerview 2, Kent Hills 2, and Ardenville wind farms, which added 189 megawatts ("MW") of renewable power to our generation portfolio. In 2010, we also decommissioned our 279 MW Wabamun coal plant.

We operate in a variety of markets to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Pacific Northwest, and Eastern Canada. 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 main driver of longer-term changes in the demand for electricity. Historically, demand for electricity in all three of our major markets has grown at an average rate of one to three per cent per year; however, the weak economic environment in 2008 and 2009 resulted in zero to negative demand growth in our key markets. Alberta began to experience some demand growth in 2010 and this trend is expected to continue at a rate of approximately three per cent per year for the next three years. Cost reductions combined with relatively well-supported oil prices are expected to result in an increase in oil sands development which will, in turn, lead to higher electricity demand. Due to the economic recession, the Pacific Northwest has seen continued demand destruction in 2010. Demand growth in this region is expe cted to increase approximately two per cent per year over the next three years due to expectations of a modest economic recovery; however, the long-term growth rate is expected to be lower than historical trends because there is a large emphasis on energy efficiency across the region. Demand in Ontario increased in 2010 coincidental with overall economic growth. In the longer term, demand in Ontario is expected to remain virtually flat and increase less than one per cent per year over the next three years as a result of economic growth being offset by conservation measures.

Supply

In all markets in which we operate, the cost of building most types of new generating capacity has decreased due to the global economic slowdown. Going forward, costs are expected to increase again as the economic recovery continues and markets tighten.

Greenhouse Gas ("GHG") legislation of some form is still expected in Canada and the U.S. Given this anticipated future legislation, new generating capacity

in the short to medium term is expected to be primarily in renewable energy and natural gas-fired generation.

Reserve margins, which measure available capacity in a market over and above the capacity needed to meet normal peak demand levels, have increased due to low or negative levels of load growth combined with new supply coming on line. It is expected that reserve margins will begin to decline slowly from current levels as load growth resumes.

Green technologies have gained favour with regulators and the general public, creating increasing pressure to supply power using renewable resources such as wind, hydro, geothermal, and solar. The economic feasibility of solar power is still being debated.

While there are many new developments that will likely impact the future supply of electricity, the low cost of our base load operations means that we expect our plants will continue to be supported in the market.

Transmission

Transmission refers to the bulk delivery system of power and energy between generating units and wholesale and/or retail customers. Power lines themselves serve as the physical path, transporting electricity from generating units to customers. Transmission systems are designed with sufficient reserve capacity to allow for "real time" fluctuations in both energy supply and demand caused by generation plants or loads increasing or decreasing output or consumption.

Transmission capacity refers to the ability of the transmission line, or lines, to safely and reliably transport electricity in an amount that balances the generating supply with the demand needs, and allows for contingency situations on the system. Most transmission businesses in North America are still regulated.

In many markets, including Alberta, investment in transmission capacity has not kept pace with the growth in demand for electricity. Lead times in new transmission infrastructure projects are significant, subject to extensive consultation processes with landowners, and subject to regulatory requirements that can change frequently. As a result, additions of generating capacity may not have ready access to markets until key bulk transmission upgrades and additions are completed.

In 2009, the Government of Alberta declared several important transmission projects as being critical, including lines between the Edmonton and Calgary regions, and between Edmonton and northeast Alberta. As a result, transmission lines within one of our key markets are expected to be upgraded to become less congested and will therefore be more efficient in meeting the needs of the long-term demand growth for electricity.

Historically, transmission systems have been designed to serve loads in only their local area, and interties between jurisdictions that were built for reliability served only a small fraction of the local generation capacity or load. Future transmission lines will need to connect beyond provincial and state borders as there is a desire to improve efficiency by transmitting large quantities of electricity from one region to another. Such interregional lines will either be alternating current or direct current high voltage lines.

Environmental Legislation and Technologies

Environmental issues and related legislation have, and will continue to have, an impact upon our business. Since 2007, we have incurred costs as a result of GHG legislation in Alberta. Legislation in other jurisdictions and at different levels of government is in various stages of maturity and sophistication. 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").

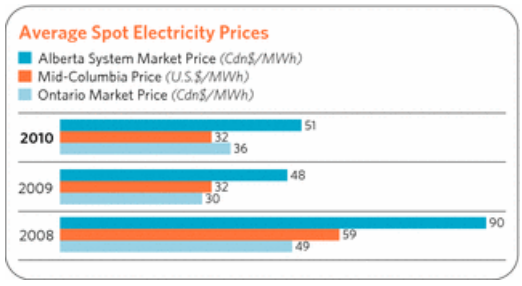
While Carbon Capture and Storage ("CCS") technologies are being developed, these technologies are not sufficiently advanced at this time. A $2 billion provincial fund and a $1 billion federal fund have been dispersed to several large demonstration projects. Project Pioneer, our CCS project, has qualified and received funding commitments of more than $750 million from these government initiatives. Those investments are expected to bring the cost of CCS down over the next 10 years. The outlook for these costs sets a floor price for carbon abatement technologies if regulatory or trading schemes are implemented. The future of carbon regulation remains uncertain.

Economic Environment

The economic environment has shown signs of improvement in 2010 and we expect this trend to continue in 2011 at a slow to moderate pace.

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. The PPAs and long-term contracts covering a number of our generating facilities help minimize the impact of spot price changes.



The major markets we operate in are Western Canada, the U.S. Pacific Northwest, and Eastern Canada. Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, and the other business environment dynamics discussed above. We monitor these trends in prices and schedule maintenance, where possible, during times of lower prices.

For the year ended Dec. 31, 2010, average spot prices increased in both Alberta and Ontario, and were comparable in the Pacific Northwest compared to the same period in 2009. In Alberta, demand growth and high prices during the second quarter resulted in a higher annual price. In Ontario, prices increased due to demand recovery. In the Pacific Northwest, marginally higher gas prices were offset by lower weather-related demand.

During the year, our consolidated power portfolio was 95 per cent contracted through the use of PPAs and other long-term contracts. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2010 ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and from U.S.$50-$55 per MWh in the Pacific Northwest.

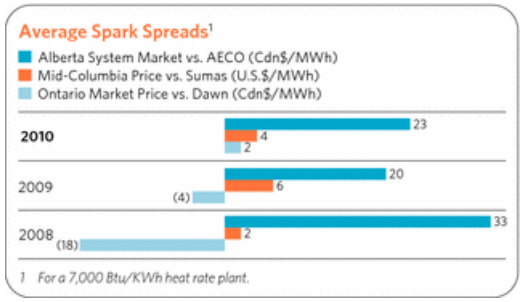
Spark Spreads

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 the fuel source to electricity. For most markets, a standardized plant heat rate is assumed to be 7,000 British Thermal Units ("Btu") per Kilowatt hour ("KWh").

Spark spreads will also vary between different plants due to their design, the geographical region 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 the resulting spark spreads in our three major markets, affect our Generation and Energy Trading business segments.

For the year ended Dec. 31, 2010, average spark spreads increased in Alberta and Ontario compared to the same periods in 2009 due to demand growth. Average spark spreads decreased in the Pacific Northwest compared to the same periods in 2009 due to lower weather-related demand during the third and fourth quarters, as well as increased generation from hydro and wind in the region.



Strategy

Our goals are to deliver shareholder value by delivering solid returns through dividend yield, and disciplined comparable Earnings Per Share[2] ("EPS") and funds from operations[2] growth, while maintaining a low-to-moderate risk profile, balancing capital allocation, and maintaining financial strength. Our comparable EPS and funds from operations growth is driven by optimizing and diversifying our portfolio, growing our renewable portfolio across Canada, and further expanding our overall portfolio and operations in the western regions of Canada and the U.S. We are focusing on these geographic areas as our expertise, scale, and access to numerous fuel resources, including coal, wind, geothermal, hydro, and natural gas, allow us to create expansion opportunities in our core markets. Our strategy to achieve these goals has the following key elements:

Financial Strategy

Our financial strategy is to maintain a strong balance sheet and investment grade credit ratings to provide a solid foundation for our long-cycle, capital-intensive, and commodity-sensitive business. A strong balance sheet and investment grade credit ratings improve 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 2010, although we started to see some demand growth, prices in our key markets remained consistent with the lower values experienced in 2009 as compared to prior years primarily due to the ongoing weak economic environment. While we are not immune to lower power prices, the impact of these lower prices is expected to be mitigated because approximately 88 per cent of 2011 and approximately 81 per cent of 2012 expected capacity across our fleet is contracted. It is this low-to-moderate risk contracting strategy that helps protect our cash flow and our strong financial position through economic cycles.

Operational Strategy

We manage our facilities to achieve stable and predictable operations that are low cost and balanced with our fleet availability target. Our target for 2011 is to increase productivity and achieve overall fleet availability of 89 to 90 per cent. Over the last three years, our average availability has been 86.6 per cent, which is below our corporate target. The lower average availability has been primarily due to the accelerated planned maintenance undertaken in 2009 and higher than normal unplanned outages at our coal-fired plants in 2009 and 2008. In 2009, we reviewed each unit and developed asset-specific maintenance plans to achieve more predictable performance and stable operations, which were observed in 2010 by achieving overall availability of 88.9 per cent.

Growth Strategy

Our growth strategy is focused upon greening and diversifying our portfolio to reduce our carbon footprint and develop long-term, sustainable power generation. We've delivered on this plan in 2010 by completing our Summerview 2, Kent Hills 2, and Ardenville wind projects on time and on budget. We continue to develop opportunities for future sustainable power projects.

2 *Comparable EPS and funds from operations are 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 of this MD&A for a further discussion of comparable EPS and funds from operations, including a reconciliation to net earnings and cash flow from operating activities.*

Capability to Deliver Results

We have numerous core competencies and non-capital resources that give us the capability 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.

Operational Excellence

We seek to optimize our generating portfolio by owning and managing a mix of relatively low-risk assets and fuels to deliver an acceptable and predictable return. The following chart demonstrates the significant progress that we have already made in each of our strategic focus areas.

Execution of our Strategy in 2010

Improve base operations	n	Implemented productivity and cost reductions that lowered operating expenses across the fleet

	n Implemented our revised major maintenance schedule on a unit-by-unit basis, which improved availability to 88.9 per cent in 2010
	n Began to align plans and capital spend for coal units based on the emerging proposal to reduce GHG emissions by their 45th year of operation
	n Approved a 15 MW efficiency uprate at Unit 3 of our Sundance facility
Reposition coal	n Participated in the Front End Engineering and Design ("FEED") study to investigate the feasibility of Project Pioneer, which uses CCS technology and is expected to be completed in 2011
	n Announced Enbridge as an official partner in the development of Project Pioneer
	n Signed a Memorandum of Understanding ("MOU") with the State of Washington and began plans to reduce GHG emissions from the Centralia Thermal plant
	n Continued active involvement in environmental policy discussions with various levels of government in Canada and the U.S.
Green and diversify our portfolio	n Added 189 MW of wind generation to our portfolio by completing construction of the Summerview 2, Kent Hills 2, and Ardenville wind farms
	n Continued our work on the construction of Bone Creek, a 19 MW hydro facility in British Columbia

Financial Strength

We manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline proved valuable during the weak economic environment of 2010 and will continue to be important during 2011. We continue to maintain $2.0 billion in committed credit facilities, and as of Dec. 31, 2010, $1.1 billion was available to us. Our investment grade credit rating, available credit facilities, strong funds from operations, and limited debt maturity profile provide us with financial flexibility, and as a result we can be selective as to if and when we go to the capital markets for funding.

The funding required for our growth strategy is supported by our financial strength. In 2010, we took advantage of favourable capital markets by completing a U.S.$300 million 30-year senior notes offering in March and completing the sale of $300 million of preferred shares in December. Both transactions were well received by the markets and were oversubscribed. Looking forward, we expect continued capital market support for projects that meet our return requirements and risk profile.

Disciplined Capital Allocation

We are committed to optimizing the balance between returning capital to shareholders, and meeting liquidity requirements, base business investment, and growth opportunities. We have a proven track record of maintaining our long-term financial stability, which includes balancing the cash distributions to our shareholders through dividends with making investments in growth projects that will deliver long-term cash flow.

We continue to grow our diversified generating fleet in order to increase production and meet future demand requirements, with all growth projects having the ability to exceed our targeted rate of return. We currently have 305 MW of capacity under construction, which is comprised of 225 MW of coal-fired generation, 61 MW of uprates to our thermal coal fleet, and 19 MW of hydro. We also have more than 1,400 MW of advanced development wind, hydro, natural gas, and geothermal projects in our development pipeline.

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 attractive rates of return. In 2010, we approved and began work on a 15 MW uprate on Unit 3 of our Sundance plant ("Unit 3"), and in 2011 we will continue our work on the Unit 3 uprate, as well as the uprates of Units 1 and 2 of our Keephills plant.

People

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, our employees' knowledge and dedication to superior operations, and our entire organization's knowledge of the energy business has resulted in a long-term proven track record of financial stability.

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

We strive to optimize the availability of our plants throughout the year to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, as well as 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, balancing our maintenance costs with optimal availability targets. Over the past three years we have achieved an average availability of 86.6 per cent, which is below our long-term target of 89 to 90 per cent. Our availability in 2010 was 88.9 per cent.



Availability for the year ended Dec. 31, 2010 increased compared to 2009 primarily due to lower planned outages at our Keephills plant, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal.

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

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.



Production for the year ended Dec. 31, 2010 increased 2,878 gigawatt hours ("GWh") compared to 2009 as a result of higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro"), lower planned and unplanned outages at our Sundance plant, lower unplanned outages at Centralia Thermal, lower planned outages at our Keephills plant, and lower economic dispatching at Centralia Thermal, partially offset by the decommissioning of Wabamun, higher planned outages at Centralia Thermal and Genesee 3, and the expiration of the long-term contract at Saranac.

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

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 reflects the cost of day-to-day operations. Our target is to offset 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 MWh of capacity.



For the year ended Dec. 31, 2010, OM&A costs per installed MWh decreased compared to 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, combined with higher installed capacity primarily as a result of the acquisition of Canadian Hydro.

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

Safety

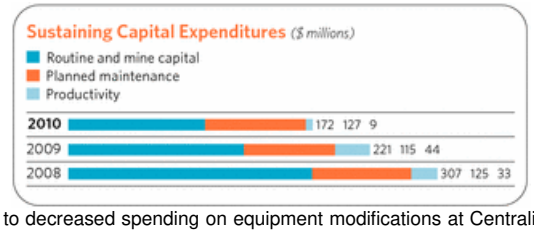
Safety is a top priority with all of our staff, contractors, and visitors. Our objective is to improve safety by reducing our Injury Frequency Rate ("IFR") to 1 by 2015. Our ultimate goal is to achieve zero injury accidents.

	2010	2009	2008
IFR	**1.19**	1.41	1.28

In 2010, the IFR decreased due to fewer injuries at our coal facilities, primarily at the Sundance plant, as a direct result of continuous efforts to improve safety. The IFR increased in 2009 as a result of us not meeting safety targets while completing the uprate on Unit 5 of our Sundance facility.

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that requires consistent and stable capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely over a long period of time. Our sustaining capital is comprised of three components: (1) routine and mine capital, (2) planned maintenance, and (3) productivity.



In 2010, we spent $49 million less on routine and mine capital, $12 million more on planned maintenance, and $35 million less on productivity compared to 2009. The decrease in routine and mine capital was due to decreased spending on equipment modifications at Centralia Thermal, lower mine capital at the Highvale mine, which supplies coal to both our Keephills and Sundance plants, and lower routine spending at Sarnia. Planned maintenance increased primarily due to higher spending on renewables as a result of the acquisition of Canadian Hydro. The decrease in productivity expenditures was primarily due to lower spend on turbine uprates at Mississauga and Windsor.

In 2009, we spent $86 million less on routine and mine capital, $10 million less on planned maintenance, and an additional $11 million on productivity compared to 2008. The decrease in both routine and mine capital and planned maintenance in 2009 was due to lower mine capital and decreased spending on equipment modifications at Centralia Thermal. The increase in productivity expenditures was for various projects undertaken throughout the Corporation to improve operations and increase efficiencies.

Earnings and Funds From Operations

We focus our base business on delivering strong earnings and funds from operations growth. Our goal is to steadily grow comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"), comparable EPS, and funds from operations over the long term, recognizing that the amount of growth may fluctuate year-over-year with the commodity cycle.

	2010	2009	2008
Comparable EPS	**0.98**	0.90	1.46
Comparable EBITDA[1]	**965**	888	1,006
Funds from operations	**783**	729	828

1 Comparable EBITDA is not defined under Canadian GAAP. Presenting comparable EBITDA 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 of this MD&A for a further discussion of

comparable EBITDA, including a reconciliation to net earnings.

In 2010, comparable EPS and comparable EBITDA increased compared to the same period in 2009 primarily due to higher availability and production, and lower OM&A costs. Comparable EPS also increased in 2010 due to lower depreciation expense.

In 2009, comparable EPS and comparable EBITDA decreased due to higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower hydro volumes and prices, and lower trading margins.

In 2010, funds from operations increased compared to the same period in 2009 due to higher availability and production, and lower operational expenditures, partially offset by higher interest payments due to the acquisition of Canadian Hydro and lower than historical wind and hydro volumes. In 2009, funds from operations decreased due to lower availability and production, and the receipt of an additional PPA payment in 2008.

Investment Grade 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 cash flow coverage ratios to support stable investment grade credit ratings.

	2010	2009	2008
Cash flow to interest coverage (times)	**4.3**	4.9	7.2
Cash flow to debt (%)	**18.3**	20.5	31.7
Debt to invested capital (%)	**53.6**	56.1	48.1

Cash flow to interest coverage decreased in 2010 compared to the same period in 2009 primarily due to higher interest expense. Cash flow to interest coverage decreased in 2009 as a result of lower funds from operations and higher interest expense. Our goal is to maintain this ratio in a range of four to five times.

Cash flow to debt decreased in 2010 compared to the same period in 2009 due to higher average debt levels in 2010. Cash flow to debt decreased in 2009 due to a decrease in funds from operations and higher debt as a result of our issuances of senior and medium-term notes during 2009 to fund the acquisition of Canadian Hydro. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital decreased as at Dec. 31, 2010 compared to the same date in 2009 due to the favourable impact of a stronger Canadian dollar on our U.S. dollar denominated debt. Debt to invested capital increased in 2009 as a result of the issuance of debt throughout the year to fund growth and for the acquisition of Canadian Hydro. Our goal is to maintain this ratio in a range of 55 to 60 per cent.

We seek to maintain financial flexibility by using multiple sources of capital to finance capital allocation plans effectively, while maintaining a sufficient level of available liquidity to support contracting and trading activities. Further, financial flexibility 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 grow our comparable Return On Capital Employed ("ROCE")[1] and Total Shareholder Return ("TSR")[1] by achieving a return of 10 per cent per year over the long-term.

The table below shows our historical performance and targets on these measures on a five-year rolling average:

	2010	2009	2008
Comparable ROCE (%)[2]	**8.0**	8.3	8.9
TSR (%)	**2.0**	12.3	12.6

2 2008 comparable ROCE is based on a four-year rolling average as we did not begin reporting comparable ROCE until 2005.

The five-year rolling average of comparable ROCE has decreased slightly due to higher debt levels primarily due to the acquisition of Canadian Hydro in 2009, partially offset by increasing comparable earnings year-over-year.

The five-year rolling average of TSR has decreased due to the decline of our stock price, which is a direct result of the economic recession that began in 2008 that has been slow to recover.

1 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. Comparable ROCE is a measure of the efficiency and profitability of capital investments and is calculated by taking comparable earnings before net interest expense, non-controlling interests and taxes, and dividing by the average invested capital excluding Accumulated Other Comprehensive Income ("AOCI"). 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.

Results of Operations

Our results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading[1] and Corporate. 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 Obligation ("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 dis cussion.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant items from the Consolidated Statements of Earnings and the Consolidated Balance Sheets. While individual line items on the Consolidated Balance Sheets will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to self-sustaining foreign operations is reflected in the equity section of the Consolidated Balance Sheets.

Highlights and Summary of Results

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

Year ended Dec. 31	**2010**	2009	2008
Availability (%)	**88.9**	85.1	85.8
Production (GWh)	**48,614**	45,736	48,891
Revenues	**2,819**	2,770	3,110
Gross margin[2]	**1,617**	1,542	1,617
Operating income[2]	**497**	378	533
Net earnings applicable to common shares	**218**	181	235
Net earnings per common share, basic and diluted	**1.00**	0.90	1.18
Comparable EPS	**0.98**	0.90	1.46
Comparable EBITDA	**965**	888	1,006
Funds from operations	**783**	729	828
Cash flow from operating activities	**811**	580	1,038
Cash flow from operating activities per share[2]	**3.70**	2.89	5.22
Free cash flow (deficiency)[2]	**204**	(117)	121
Dividends paid per common share	**1.16**	1.16	1.08

As at Dec. 31	**2010**	2009	2008
Total assets	**9,893**	9,786	7,824
Total long-term liabilities	**5,108**	5,548	3,645

2 Gross margin, operating income, cash flow from operating activities per share, and free cash flow (deficiency) are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings and cash flow from operating activities.

1 Our Energy Trading segment was referred to as "Commercial Operations and Development" in 2009 and 2008.

Reported Earnings

The primary factors contributing to the change in net earnings applicable to common shares for the years ended Dec. 31, 2010 and 2009 are presented below:

Net earnings applicable to common shares for the year ended Dec. 31, 2008	235
Decrease in Generation gross margins	(33)
Mark-to-market movements - Generation	16
Decrease in Energy Trading gross margins	(58)
Increase in operations, maintenance, and administration costs	(30)
Increase in depreciation expense	(47)
Asset impairment charges	(16)
Increase in net interest expense	(34)
Equity loss recorded in 2008	97
Decrease in non-controlling interests	23
Decrease in income tax expense	8
Increase in foreign exchange gain	20
Net earnings applicable to common shares for the year ended Dec. 31, 2009	181
Increase in Generation gross margins	36
Mark-to-market movements - Generation	45
Decrease in Energy Trading gross margins	(6)
Decrease in operations, maintenance, and administration costs	33
Decrease in depreciation expense	16
Asset impairment charges	(73)
Increase in net interest expense	(34)

Decrease in other income	(8)
Decrease in non-controlling interests	18
Decrease in income tax expense	14
Other	(4)
Net earnings applicable to common shares for the year ended Dec. 31, 2010	**218**

For the year ended Dec. 31, 2010, Generation gross margins, excluding the impact of mark-to-market movements, increased compared to the same period in 2009 due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, lower planned and unplanned outages at our Sundance plant, and lower planned outages at our Keephills plant, partially offset by unfavourable pricing, the expiration of the long-term contract at Saranac, the decommissioning of Wabamun, and unfavourable foreign exchange rates.

In 2009, Generation gross margins, excluding the impact of mark-to-market movements, decreased due to higher planned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower hydro volumes and prices, and the expiration of the long-term contract at Saranac, partially offset by lower planned and unplanned outages at Genesee 3, lower unplanned outages at Keephills, higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, favourable foreign exchange rates, and favourable contractual pricing.

Mark-to-market movements increased for the year ended Dec. 31, 2010 primarily due to the recognition of unrealized gains resulting from certain power hedging relationships being deemed ineffective for accounting purposes.

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased compared to the same period in 2009 primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

In 2009, Energy Trading gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

For the year ended Dec. 31, 2010, OM&A costs decreased compared to the same period in 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by the acquisition of Canadian Hydro.

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

For the year ended Dec. 31, 2010, depreciation expense decreased compared to the same period in 2009 due to a change in the estimated useful lives of certain coal generation facilities and mining assets, a reduction in the estimated costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

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

During the fourth quarter of 2010, we recorded pre-tax asset impairment charges of $89 million related to certain coal and natural gas facilities. Refer to the Asset Impairment section of this MD&A for further details.

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

For the year ended Dec. 31, 2010, net interest expense increased compared to the same period in 2009 due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

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

In 2009, we settled an outstanding commercial issue that was recorded as a pre-tax gain of $7 million in other income as it related to our previously held Mexican equity investment. We also recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm. The sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

For the year ended Dec. 31, 2010, non-controlling interests decreased compared to the same period in 2009 due to lower earnings resulting from the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TA Cogeneration, L.P. ("TA Cogen").

In 2009, non-controlling interests decreased primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac.

For the year ended Dec. 31, 2010, income tax expense decreased compared to the same period in 2009 as a result of the resolution of certain outstanding tax matters, partially offset by higher pre-tax earnings.

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

Significant Events

Our consolidated financial results include the following significant events:

2010

Sale of Meridian

On Dec. 20, 2010, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, all associated assets and liabilities have been classified as held for sale under the Generation segment. The sale is effective Jan. 1, 2011 and is expected to close in early 2011. The impact of this transaction on net earnings is not expected to be significant.

Purchase Price Allocation Adjustment

During the fourth quarter of 2010, management updated the preliminary purchase price allocation related to our acquisition of Canadian Hydro to better reflect the value of the underlying assets and liabilities acquired. As a result, a $114 million adjustment was made to depreciable assets, producing a $4 million decrease in depreciation expense. The adjustment to depreciable assets was offset by adjustments to goodwill and future income taxes.

Sundance Unit 1 and 2 Outage

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of our Sundance facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units were unavailable as inspections were carried out to determine the scope of repairs that may be needed. The units cannot be restarted without inspection and approval from the Alberta Boiler Safety Association. As a result of the outage, production was reduced by 182 GWh for the year ended Dec. 31, 2010.

Under the terms of the PPA for these units, we have notified the PPA Buyer and the Balancing Pool of a force majeure event. Under force majeure, we are entitled to receive our PPA capacity payments and are protected from having to pay penalties for the units' lack of availability, to the extent the event meets the force majeure criteria set out in the PPA.

On Feb. 8, 2011, we announced that we had issued a notice of termination for destruction on our Sundance 1 and 2 coal-fired generation units under the terms of the PPA. This action was based on our determination that the physical state of the boilers is such that the units cannot be economically restored to service under the terms of the PPA. Under the PPA, termination for destruction permits the recovery of the net book value specified in the PPA.

On Feb. 18, 2011, the PPA Buyer has provided notice that it intends to dispute our notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. Although no assurance can be given as to the ultimate outcome of these matters, we believe that they will be resolved in our favour. We remain committed to continuing to work with the PPA Buyer and the Balancing Pool under the processes established within the PPA.

Resolution of Tax Matters

During 2010, we recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters, which was received in 2010. Interest expense also decreased by $14 million as a result of tax-related interest recoveries.

Sale of Preferred Shares

On Dec. 10, 2010, we completed our public offering of 12 million Series A 4.60 per cent Cumulative Rate Reset First Preferred Shares, resulting in gross proceeds of $300 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Kent Hills 2

On Nov. 21, 2010, the 54 MW expansion of our Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010, and an additional $2 million of proceeds related to costs expected in 2011. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

Ardenville

On Nov. 10, 2010, our 69 MW Ardenville wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $135 million.

Project Pioneer

On Nov. 28, 2010, we announced that the Global Carbon Capture and Storage Institute awarded the Corporation AUD$5 million to share knowledge around the world from Project Pioneer, Canada's first fully integrated CCS project involving retrofitting a coal-fired generation plant. The funding will help Project Pioneer both contribute to and access international research and leading-edge knowledge from a global CCS forum.

On June 28, 2010, we announced that Enbridge Inc. ("Enbridge") will officially participate as a partner in the development of Project Pioneer.

Sundance Unit 3 Uprate

On Sept. 13, 2010, we obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of our Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed chief financial officer, succeeding Brian Burden, who made a personal decision to retire from the Corporation. Mr. Burden assisted Mr. Gellner with the transition through Sept. 30, 2010.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 of our Sundance facility due to the mechanical failure of critical generator components. As a result, the expected capability levels for Unit 3 were reduced. Unit 3 returned to service at the reduced expected capability levels on June 23, 2010. The unit continues to operate at these reduced levels and no assurance can be given as to whether it will return to normal operating levels prior to the completion of major maintenance currently scheduled for the middle of 2012. As a result of the outage and subsequent derate, production was reduced by 480 GWh for the year ended Dec. 31, 2010.

In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. During the second quarter, we recorded an after-tax charge of $13 million, or 50 per cent of the penalties to June 30, 2010, representing the amount of penalties we are required to pay to the PPA Buyers pending a resolution of this matter. No additional penalties relating to this event were incurred during the year.

On Oct. 20, 2010, the Balancing Pool confirmed it agreed with our determination that the mechanical failure meets the requirements of a HILP event under the PPA. While this decision neither constitutes a determination of a force majeure event, nor provides a definitive resolution to the dispute, management believes this strengthens our position with regards to financial protection from the event.

Dividend Reinvestment and Share Purchase ("DRASP")

On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. Under the terms of our DRASP plan, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. The Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

Centralia Thermal MOU

On April 26, 2010, we announced that we signed an MOU with the State of Washington to enter discussions to develop an agreement to significantly reduce GHG emissions from the Centralia Thermal plant, and to provide replacement capacity by 2025. The MOU also recognizes the need to protect the value that Centralia Thermal brings to our shareholders. Discussions are ongoing and details on the results of these discussions will be provided as they become available.

Decommissioning of Wabamun Plant

On March 31, 2010, we fully retired all units of the Wabamun plant as part of our previously announced shutdown. Over the next several years, we will complete the Wabamun plant remediation and reclamation work as approved by the Government of Alberta. Based on our review of our schedule and detailed costing of the decommissioning and reclamation activities, the asset retirement obligation associated with the Wabamun plant was reduced by $14 million during the first quarter of 2010, with the offset recorded as a recovery in depreciation.

Senior Notes Offering

On March 12, 2010, we completed our offering of U.S.$300 million senior notes maturing in 2040 and bearing an interest rate of 6.50 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

Summerview 2

On Feb. 23, 2010, our 66 MW Summerview 2 wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $118 million.

Change in Economic Useful Life

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, our economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to the same period in 2009.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

2009

Medium-Term Notes Offerings

On Nov. 18, 2009, we completed our offering in the Canadian bond market of $400 million medium-term notes maturing in 2019 and bearing an interest rate of 6.40 per cent. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

On May 29, 2009, we completed our offering in the Canadian bond market of $200 million medium-term notes maturing in 2014 and bearing an interest rate of 6.45 per cent. The net proceeds from the offering were used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

Senior Notes Offering

On Nov. 13, 2009, we completed our offering of U.S.$500 million senior notes maturing in 2015 and bearing an interest rate of 4.75 per cent. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

Sale of Common Shares

On Nov. 5, 2009, we completed our public offering of 20,522,500 common shares at a price of $20.10 per common share, which resulted in net proceeds of approximately $396 million. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

Blue Trail

On Nov. 2, 2009, our Blue Trail wind farm began commercial operations on budget and one month ahead of schedule. The 66 MW facility is located southwest of Fort MacLeod in southern Alberta.

Keephills 3

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

Carbon Capture and Storage

On Oct. 14, 2009, the federal and provincial governments announced that our CCS project, Project Pioneer, has received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a FEED study to determine if the project is viable. The FEED study is expected to cost $20 million; $10 million will come from the federal government, $5 million will come from the provincial government, and $5 million will come from TransAlta and from industry partners Alstom Canada, Capital Power Corporation ("Capital Power"), and Enbridge. The FEED study is expected to be completed in 2011, and if we proceed with construction, the prototype plant has a targeted start-up date of 2015.

Acquisition of Canadian Hydro

On Oct. 5, 2009, we entered into a definitive pre-acquisition agreement with Canadian Hydro to acquire all of their issued and outstanding common shares for $5.25 per share in cash. On Oct. 23, 2009, we acquired 87 per cent of Canadian Hydro through the purchase of all of their issued and outstanding shares. On Nov. 4, 2009, we acquired the remaining 13 per cent. The total cash consideration of the acquisition was $766 million. The results of Canadian Hydro are

included in our consolidated financial statements from Oct. 23, 2009, when we acquired control.

Canadian Hydro operated 694 MW of wind, hydro, and biomass facilities in Alberta, Ontario, Quebec, and British Columbia. Canadian Hydro's assets are highly contracted with counterparties of recognized financial standing. On a combined basis at Dec. 31, 2009, we had 9,199 MW of gross generating capacity[1] in operation (8,775 MW net ownership interest). The combined renewables portfolio included more than 1,900 MW in operation, or 22 per cent of our total portfolio at that time. In addition, there was a combined 424 MW net under construction and over 600 MW in advanced-stage development at Dec. 31, 2009.

The following table depicts the impact of Canadian Hydro on our consolidated operations portfolio by geographic region and fuel type at Dec. 31, 2009:

Net Capacity Ownership Interest (MW)

Dec. 31, 2009	Canadian Hydro	TransAlta[2]	TransAlta consolidated
Western Canada	183	5,059	5,242
Eastern Canada	511	707	1,218
International	-	2,315	2,315
	694	8,081	8,775
Coal	-	4,967	4,967
Natural Gas	-	1,843	1,843
Biomass	25	-	25
Geothermal	-	164	164
Wind	583	300	883
Hydro	86	807	893
	694	8,081	8,775

2 Excluding Canadian Hydro.

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.

Sarnia Contract

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

Major Maintenance Plans

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

Normal Course Issuer Bid ("NCIB") Program

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

Chief Operating Officer

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

Additionally, Richard Langhammer, Executive Vice-President of Generation Operations, took on a new assignment as Chief Productivity Officer for the remainder of 2009 with the responsibility for identifying strategies to create sustainable costs savings across the Corporation. Mr. Langhammer formally retired at the end of 2009 after 23 years of service.

Ardenville Wind Power Project

On April 28, 2009, we announced plans to design, build, and operate Ardenville, a 69 MW wind power project in southern Alberta. The capital cost of the project was approximately $135 million. Included in the capital cost of the project was the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the Ardenville wind project began on Nov. 10, 2010.

Sundance Unit 4 Derate

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

In response to this, we gave notice of a HILP event and claimed force majeure relief to the PPA Buyer and the Balancing Pool, and we paid the required penalties related to the derate. On April 27, 2009, the Balancing Pool rejected our assertion that this outage should be regarded as a HILP force majeure event. As a result, we also recorded an additional charge in the second quarter of 2009 of $7 million after-tax related to this event. We settled the issue in the third quarter and the terms of the settlement are confidential.

Keephills Units 1 and 2 Uprates

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

Dividend Increase

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

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. We constructed, own, and operate the Kent Hills facility. Total capital costs for the construction of Kent Hills were approximately $170 million. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills project subsequent to the commencement of commercial operations.

Debentures

On July 31, 2008, $100 million of debentures issued by TransAlta Utilities Corporation ("TAU") were redeemed at the option of 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 were 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 was no longer a reporting issuer.

On Jan. 1, 2009, TAU transferred certain generation and transmission assets to a newly formed wholly owned partnership, TransAlta Generation Partnership ("TAGP"), before amalgamating with TransAlta Corporation.

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 Capital Power (225 MW net ownership interest), experienced an unplanned outage as a result of a turbine blade failure. Capital Power, 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 Equity Investment

On Oct. 8, 2008, we successfully completed the sale of our Mexican equity investment to InterGen Global Ventures B.V. for gross proceeds of $334 million (U.S.$304 million). The sale included the plants and all associated commercial arrangements. The actual after-tax loss as a result of the sale was $62 million. The pre-tax charge of $97 million was 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 Corporation and was not in the best interest of TransAlta and its shareholders. The Board of Directors 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 was approximately $118 million and commercial operations commenced on Feb. 23, 2010.

Senior Notes 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 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.

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). Purchases were made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. 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).

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 was approximately $77 million. Commercial operations commenced in the fourth quarter of 2009.

Greenhouse Gas Emissions

March 31, 2008 marked the deadline for the first compliance year with Alberta's Specified Gas Emitters Regulation 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 P PA 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.

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 was $113 million. Commercial operations commenced in the fourth quarter of 2009.

Discussion of Segmented Results

GENERATION: Owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, 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, 2010, Generation had 9,109 MW of gross generating capacity in operation (8,676 MW net ownership interest) and 305 MW (net ownership interest) under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of this MD&A.

During 2010, we began commercial operations at our Summerview 2, Kent Hills 2, and Ardenville wind farms, which added 189 MW of renewable power to our generation portfolio. In 2010, we also decommissioned our 279 MW Wabamun plant. Please refer to the Significant Events section of this MD&A for further details.

We have strategic alliances with Stanley Power, Capital Power, ENMAX Corporation ("ENMAX"), MidAmerican Energy Holdings Company ("MidAmerican"), Nexen Incorporated ("Nexen"), and Brookfield Asset Management Inc. ("Brookfield"). Stanley Power owns the minority interest in TA Cogen. The Capital Power alliance provided the opportunity for us to acquire 50 per cent ownerships in both the 450 MW Genesee 3 project and the Taylor Hydro facility, as well as to build the Keephills 3 project. ENMAX and our Corporation each own 50 per cent of the McBride Lake wind project. MidAmerican owns the other 50 per cent interest in CE Generation, LLC ("CE Gen") and Wailuku Holding Company, LLC. Nexen and our Corporation each have a 50 per cent ownership in the Soderglen wind project. Brookfield owns the other 50 per cent interest in our Pingston hydro facility.

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:

Year ended Dec. 31	2010		2009		2008	
	Total	Per installed MWh	Total	Per installed MWh	Total	Per installed MWh
Revenues	**2,778**	**34.90**	2,723	36.37	3,005	40.63
Fuel and purchased power	**1,202**	**15.10**	1,228	16.40	1,493	20.18
Gross margin	**1,576**	**19.80**	1,495	19.97	1,512	20.45
Operations, maintenance, and administration	**549**	**6.90**	550	7.35	487	6.58
Depreciation and amortization	**438**	**5.50**	453	6.05	409	5.53
Taxes, other than income taxes	**27**	**0.34**	22	0.29	19	0.26
Intersegment cost allocation	**5**	**0.06**	32	0.43	30	0.41
Operating expenses	**1,019**	**12.80**	1,057	14.12	945	12.78
Operating income	**557**	**7.00**	438	5.85	567	7.67
Installed capacity (GWh)	**79,591**		74,866		73,969	
Production (GWh)	**48,614**		45,736		48,891	
Availability (%)	**88.9**		85.1		85.8	

Generation Production and Gross Margins

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

Year ended Dec. 31, 2010	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	**25,025**	**31,325**	**813**	**335**	**478**	**25.95**	**10.69**	**15.26**
Gas	**3,981**	**4,866**	**232**	**76**	**156**	**47.68**	**15.62**	**32.06**
Renewables	**2,506**	**11,120**	**142**	**10**	**132**	**12.77**	**0.90**	**11.87**
Total Western Canada	**31,512**	**47,311**	**1,187**	**421**	**766**	**25.09**	**8.90**	**16.19**
Gas	**3,816**	**6,570**	**435**	**243**	**192**	**66.21**	**36.99**	**29.22**
Renewables	**1,330**	**5,435**	**126**	**7**	**119**	**23.18**	**1.29**	**21.89**
Total Eastern Canada	**5,146**	**12,005**	**561**	**250**	**311**	**46.73**	**20.82**	**25.91**
Coal	**8,594**	**12,053**	**773**	**470**	**303**	**64.13**	**38.99**	**25.14**
Gas	**2,063**	**6,736**	**140**	**56**	**84**	**20.78**	**8.31**	**12.47**
Renewables	**1,299**	**1,486**	**117**	**5**	**112**	**78.73**	**3.36**	**75.37**
Total International	**11,956**	**20,275**	**1,030**	**531**	**499**	**50.80**	**26.19**	**24.61**
	48,614	**79,591**	**2,778**	**1,202**	**1,576**	**34.90**	**15.10**	**19.80**

Year ended Dec. 31, 2009	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	24,517	32,833	838	349	489	25.52	10.63	14.89
Gas	4,035	4,744	228	79	149	48.06	16.65	31.41
Renewables	1,891	8,757	116	7	109	13.25	0.80	12.45
Total Western Canada	30,443	46,334	1,182	435	747	25.51	9.39	16.12
Gas	3,377	6,570	388	224	164	59.06	34.09	24.97
Renewables	452	1,686	40	1	39	23.72	0.59	23.13
Total Eastern Canada	3,829	8,256	428	225	203	51.84	27.25	24.59
Coal	7,450	12,053	767	476	291	63.63	39.49	24.14
Gas	2,637	6,736	213	82	131	31.62	12.17	19.45
Renewables	1,377	1,486	133	10	123	89.50	6.73	82.77
Total International	11,464	20,275	1,113	568	545	54.89	28.01	26.88
	45,736	74,865	2,723	1,228	1,495	36.37	16.40	19.97

Year ended Dec. 31, 2008	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	26,327	32,788	856	374	482	26.11	11.41	14.70
Gas	3,875	4,718	291	145	146	61.68	30.73	30.95
Renewables	2,162	8,590	167	6	161	19.44	0.70	18.74
Total Western Canada	32,364	46,096	1,314	525	789	28.51	11.39	17.12
Gas	3,290	7,194	501	351	150	69.64	48.79	20.85
Total Eastern Canada	3,290	7,194	501	351	150	69.64	48.79	20.85
Coal	8,753	12,327	756	467	289	61.33	37.88	23.45
Gas	3,152	6,861	298	111	187	43.43	16.18	27.25
Renewables	1,332	1,491	136	39	97	91.21	26.16	65.05
Total International	13,237	20,679	1,190	617	573	57.55	29.84	27.71
	48,891	73,969	3,005	1,493	1,512	40.63	20.18	20.45

Western Canada

Our Western Canada assets consist of four coal plants, three natural gas-fired facilities, 20 hydro facilities, 12 wind farms, and one biomass facility with a total gross generating capacity of 5,384 MW (5,098 MW net ownership interest). In 2010, we decommissioned our 279 MW Wabamun plant and also began commercial operations at Ardenville, a 69 MW wind farm, and Summerview 2, a 66 MW wind farm. We are currently constructing Keephills 3, a 450 MW (225 MW net ownership interest) merchant coal plant, under a joint venture with Capital Power, which is scheduled to enter commercial production in 2011. We are currently performing uprates of 23 MW each on Unit 1 and Unit 2 of our Keephills plant, which are scheduled to be completed by the fourth quarter of 2012. We are also currently constructing Bone Creek, a hydro facility in British Columbia, which will have a generating capacity of 19 MW and is scheduled t o enter commercial production in 2011.

Our Sundance, Keephills, and Sheerness plants, and 13 hydro facilities operate under PPAs with a gross generating capacity of 4,083 MW (3,888 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 Genesee 3 plant, a portion of Poplar Creek and Castle River, four hydro facilities, and 11 additional wind farms 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.

McBride Lake, Meridian, Fort Saskatchewan, three hydro facilities, and a significant portion of Poplar Creek and Castle River 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 10 years and payments do not fluctuate significantly with changes in levels of production.

Our Grande Prairie biomass facility earns revenues under long-term contracts based on actual production delivered at a specified price per MWh.

For the year ended Dec. 31, 2010, production increased 1,069 GWh compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant, lower planned outages at our Keephills plant, and higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro, partially offset by the decommissioning of Wabamun.

In 2009, production decreased 1,921 GWh due to higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower PPA customer demand, and lower hydro volumes, partially offset by lower planned and unplanned outages at Genesee 3, lower unplanned outages at Keephills, and higher wind volumes due to the acquisition of Canadian Hydro.

Gross margin for the year ended Dec. 31, 2010 increased $19 million ($0.07 per installed MWh) compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant, higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, and lower planned outages at our Keephills plant, partially offset by unfavourable pricing and the decommissioning of Wabamun.

In 2009, gross margin decreased $42 million ($1.00 per installed MWh) due to higher planned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, and lower hydro volumes and prices, partially offset by lower planned and unplanned outages at Genesee 3, lower unplanned outages at Keephills, an adjustment to prior period indices, lower penalties due to lower spot prices, and higher wind volumes due to the acquisition of Canadian Hydro.

Eastern Canada

In 2010, we began commercial operations at Kent Hills 2, a 54 MW expansion of our Kent Hills wind farm in New Brunswick. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations.

Our Eastern Canada assets consist of four natural gas-fired facilities, five hydro facilities, and five wind farms with a total gross generating capacity of 1,410 MW (1,263 MW net ownership interest). All of our assets in Eastern Canada earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Our Windsor facility also sells a portion of its production on the merchant spot market.

For the year ended Dec. 31, 2010, production increased 1,317 GWh compared to the same period in 2009 due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, and market conditions at our natural gas-fired facilities.

In 2009, production increased 539 GWh primarily due to higher wind and hydro volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills.

For the years ended Dec. 31, 2010 and 2009, gross margin increased $108 million ($1.32 per installed MWh) and $53 million ($3.74 per installed MWh), respectively, due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, and market conditions at our natural gas-fired facilities.

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 2,015 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 in which we have a 50 per cent interest.

Our Centralia Thermal, Centralia Gas, Power Resources, Skookumchuck, and two units 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, 2010, production increased 492 GWh compared to the same period in 2009 primarily due to lower unplanned outages and lower economic dispatching at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal and the expiration of our long-term contract at Saranac in the second quarter of 2009.

In 2009, production decreased 1,773 GWh due to higher unplanned outages and higher economic dispatching at Centralia Thermal, and the expiration of the long-term contract at Saranac, partially offset by lower planned outages at Centralia Thermal.

For the year ended Dec. 31, 2010, gross margins decreased $46 million ($2.27 per installed MWh) compared to the same period in 2009 primarily due to the expiration of the long-term contract at Saranac and unfavourable foreign exchange rates, partially offset by favourable mark-to-market movements and favourable pricing primarily related to purchased power.

In 2009, gross margins decreased $28 million ($0.83 per installed MWh) due to the expiration of the long-term contract at Saranac, higher coal costs, and lower production at Centralia Thermal, partially offset by favourable foreign exchange, favourable pricing, and favourable mark-to-market movements.

During the fourth quarter of 2010, unrealized pre-tax gains of $43 million were recorded in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

The long-term contract between our Saranac facility and New York State Electric and Gas expired in June 2009. The facility now operates under a combined capacity and merchant dispatch contract, resulting in lower production and gross margin for the year ended Dec. 31, 2010. As a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. The net pre-tax earnings impact of the expiration of this contract is a decrease of approximately $10 million for the year ended Dec. 31, 2010.

Operations, Maintenance, and Administration

For the year ended Dec. 31, OM&A expenses decreased compared to the same period in 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010 and the acquisition of Canadian Hydro.

In 2009, OM&A expenses increased primarily due to higher planned outages, unfavourable foreign exchange rates, and the acquisition of Canadian Hydro, partially offset by targeted cost savings.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed:

Year ended Dec. 31	**2010**	2009	2008
Capitalized	**127**	115	125
Expensed	**70**	118	68
	197	233	193
GWh lost	**2,739**	3,732	3,478

For the year ended Dec. 31, 2010, total planned maintenance costs decreased $36 million compared to the same period in 2009 due to lower planned outages across the fleet. In 2010, production lost as a result of planned maintenance decreased 993 GWh compared to the same period in 2009 primarily due to lower planned outages at our Sundance plant and Centralia Thermal.

In 2009, total planned maintenance costs increased $40 million due to higher planned outages across the fleet and cost escalations. Production lost as a result of planned maintenance increased by 254 GWh primarily due to the uprate on Unit 5 at our Sundance plant.

Depreciation Expense

For the year ended Dec. 31, 2010, depreciation expense decreased compared to the same period in 2009 due to a change in the estimated useful lives of certain coal generation facilities and mining assets, a reduction in the estimated costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

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

Asset Impairment Charges

During the fourth quarter of 2010, we completed our annual comprehensive impairment assessment based on fair value estimates derived from our long-range forecast and market values evidenced in the marketplace. As a result, we recorded pre-tax asset impairment charges of $89 million ($79 million after deducting the amount that is attributable to the non-controlling interest) on certain Generation assets, comprised of a $65 million charge against our natural gas fleet and a $24 million charge against our coal fleet. The natural gas fleet impairment reflects lower forecast pricing at one of our merchant facilities and the pending sale of our 50 per cent interest in our Meridian facility, which had no impact to consolidated earnings as the impairment was attributable to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at our Sundance facility and primarily reflects our shift in 2010 to managing our coal-fired generation facilities on a unit pair basis, resulting in the impairment assessment now being performed on a unit pair basis.

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

ENERGY TRADING: 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 Energy Trading's activities.

Energy Trading 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 and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results 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 earnings 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 Energy Trading is allocated to the Generation segment based on an estimate of operating expenses and a percentage of resources dedicated to providing support and analysis. This fixed fee intersegment allocation is represented as a cost recovery in Energy Trading and an operating expense within Generation. During 2010, certain support costs previously borne by the Energy Trading segment and recovered through the intersegment fee started being directly charged to the Generation segment.

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

Year ended Dec. 31	**2010**	2009	2008
Gross margin	**41**	47	105
Operations, maintenance, and administration	**17**	31	53
Depreciation and amortization	**2**	4	3
Intersegment cost allocation	**(5)**	(32)	(30)

Operating expenses	**14**	3	26
Operating income	**27**	44	79

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased compared to the same period in 2009 primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

In 2009, Energy Trading gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

For the year ended Dec. 31, 2010, OM&A costs and the intersegment fee decreased compared to the same period in 2009 as a result of the change in how we record certain support costs between the Energy Trading and Generation segments, as described above.

For the year ended Dec. 31, 2009, OM&A expenses decreased due to a reduction in both discretionary expenditures and staff compensation costs. The intersegment fee in 2009 was comparable to 2008.

CORPORATE: Our Generation and Energy Trading business 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.

The expenses incurred by the Corporate segment are as follows:

Year ended Dec. 31	**2010**	2009	2008
Operations, maintenance, and administration	**68**	86	97
Depreciation and amortization	**19**	18	16
Operating expenses	**87**	104	113

OM&A costs for the year ended Dec. 31, 2010 decreased compared to the same period in 2009 primarily due to information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010.

In 2009, OM&A costs decreased primarily due to a reduction in staff compensation costs.

Net Interest Expense

Year ended Dec. 31	**2010**	2009	2008
Interest on debt	**243**	183	177
Capitalized interest	**(48)**	(36)	(21)
Interest income from the resolution of certain outstanding tax matters	**(14)**	-	(30)
Interest income	**(3)**	(6)	(16)
Other	**-**	3	-
Net interest expense	**178**	144	110

Net interest expense for the year ended Dec. 31, 2010 increased compared to the same period in 2009 due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

In 2009, net interest expense increased due to higher debt levels and lower interest income as a result of the receipt of interest income from a tax settlement in 2008, partially offset by lower interest rates and higher capitalized interest primarily due to the construction of Keephills 3.

Other Income

In 2009, we settled an outstanding commercial issue that was recorded as a pre-tax gain of $7 million in other income as it related to our previously held Mexican equity investment. We also recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm. The sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

Non-Controlling Interests

We own 50.01 per cent of 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. Stanley Power 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. Natural Forces owns a 17 per cent interest in our Kent Hills facility, which operates 150 MW of wind assets. Since we own a controlling interest in TA Cogen and Kent Hills, we consolidate the entire earnings, assets, and liabilities in relation to our ownership of those assets. For Saranac, we proportionately consolidate our share of the earnings, assets, and liabilities in relation to our ownership.

Non-controlling interests on the Consolidated Statements of Earnings and Consolidated Balance Sheets relate to the earnings and net assets attributable to TA Cogen, Saranac, and Kent Hills that we do not own. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen, Saranac, and Kent Hills is shown as distributions paid to subsidiaries' non-controlling interests in the financing section.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2010 decreased compared to the same period in 2009 due to lower earnings at CE Gen as a result of the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TA Cogen.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2009 decreased due to lower earnings at CE Gen as a result of the expiration of the long-term contract at our Saranac facility and lower earnings at TA Cogen.

Income Taxes

Our income tax rates and tax expense are based on the earnings generated in each jurisdiction in which we operate and any permanent differences between how pre-tax income is calculated for accounting and tax purposes. If there is a timing difference between when an expense or revenue item is recognized for accounting and tax purposes, these differences result in future income tax assets or liabilities and are measured using the income tax rate expected to be in effect when these temporary differences reverse. The impact of any changes in future income tax rates on future income tax assets or liabilities is recognized in earnings in the period the new rates are substantively enacted.

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

Year ended Dec. 31	2010	2009	2008
Earnings before income taxes	**220**	196	258
Asset impairment charges	**79**	16	-
Unrealized gains related to ineffectiveness in certain power hedging relationships	**(43)**	**-**	-
Settlement of commercial issue	**-**	(7)	-
Change in life of Centralia parts	**-**	2	18
Gain on sale of assets at Centralia	**-**	-	(6)
Writedown of Mexican equity investment	**-**	-	97
Comparable earnings[1] before income taxes	**256**	207	367
Income tax expense	**1**	15	23
Income tax recovery on asset impairment charges	**25**	6	-
Income tax expense related to ineffectiveness in certain power hedging relationships	**(15)**	-	-
Income tax recovery related to the resolution of certain outstanding tax matters	**30**	-	-
Income tax expense on settlement of commercial issue	**-**	(1)	-
Income tax recovery on change in life of Centralia parts	**-**	1	6
Income tax recovery related to change in future tax rates	**-**	5	-
Income tax expense on gain on sale of assets at Centralia	**-**	-	(2)
Income tax recovery recorded on the sale of our Mexican equity investment	**-**	-	35
Income tax recovery related to tax positions	**-**	-	15
Income tax expense excluding non-comparable items	**41**	26	77
Effective tax rate on comparable earnings before income taxes (%)	**16**	13	21

1 *Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of this item, as well as a reconciliation to net earnings.*

Income tax expense excluding non-comparable items increased for the year ended Dec. 31, 2010 compared to the same period in 2009 as a result of higher comparable earnings before income taxes.

In 2009, the income tax expense excluding non-comparable items decreased due to lower pre-tax earnings and the recovery recorded for a change in future tax rates related to tax liabilities recorded in prior periods, partially offset by the tax recovery related to tax positions recorded in 2008.

The effective tax rate increased for the year ended Dec. 31, 2010 and decreased for the year ended Dec. 31, 2009 primarily due to certain deductions that do not fluctuate with earnings and a change in the mix of jurisdictions where pre-tax income is earned.

Financial Position

The following chart outlines significant changes in the Consolidated Balance Sheets from Dec. 31, 2009 to Dec. 31, 2010:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	**(24)**	Improved cash management
Income taxes receivable	**(20)**	Recovery of tax prepayments and overpayments
Inventory	**(37)**	Higher production at coal facilities
Long-term receivable	**(49)**	Resolution of certain outstanding tax matters
Risk management assets (current and long-term)	**105**	Price movements
Property, plant, and equipment, net	**18**	Capital additions, partially offset by depreciation, the Canadian Hydro purchase price allocation adjustment, asset impairment, and foreign exchange
Assets held for sale	**60**	Meridian assets
Goodwill	**83**	Canadian Hydro purchase price allocation adjustment
Intangible assets	**(40)**	Canadian Hydro purchase price allocation adjustment and amortization expense
Accounts payable and accrued liabilities	**(18)**	Timing of payments, combined with lower operational expenditures
Collateral received	**40**	Collateral collected from counterparties as a result of a change in forward prices
Dividends payable	**69**	Timing of Q1 2011 quarterly cash dividend declaration
Long-term debt (including current portion)	**(208)**	Repayment of long-term debt, partially offset by the issuance of U.S.$300 million senior notes

Risk management liabilities (current and long-term)	**35**	Price movements
Asset retirement obligation (including current portion)	**(40)**	Revised cost estimate of the decommissioning of our Wabamun plant and foreign exchange
Deferred credits and other long-term liabilities	**22**	Timing of deferred revenues and commitments
Non-controlling interests	**(43)**	Distributions and hedging losses in excess of earnings attributable to non-controlling interest and increased investment in Kent Hills
Shareholders' equity	**248**	Issuance of preferred shares, net earnings, and movements in AOCI, partially offset by 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 Consolidated Balance S heets as risk management assets and liabilities.

We have two types of financial instruments: (1) those that are used in the Energy Trading 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 operations. The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using 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 Consolidated Statements of Earnings as a result of differences between the contract price and the current forecast of future prices. We record the changes in fair value of these contracts through the Consolidated Statements of Comprehensive Income. When these contracts are settled, the value previously recorded in Other Comprehensive Income ("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. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI, as discussed above, while any ineffective portion is recognized in net earnings.

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 Consolidated Statements 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.

All gains or losses related to fair value hedges are recorded on the Consolidated Statements of Earnings, which, in turn, are completely offset by the value of the gains or losses related to the hedged risk of the debt instruments on the foreign currency denominated assets and liabilities.

A summary of how typical fair value hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	-	-	-	-
Reporting date (marked-to-market)	ü	-	ü	-
Settle contract	ü	-	ü	ü

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.

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 typical project hedges are recorded in our financial statements is as follows:

	Consolidated	Consolidated Statements of	Consolidated	Consolidated

Event	Statements of Earnings	Comprehensive Income	Balance Sheets	Statements of Cash Flows
Enter into contract[1]	-	-	-	-
Reporting date (marked-to-market)[2]	-	ü	ü	-
Roll-over into new contract	-	ü	ü	ü
Settle contract	-	ü	ü	ü

1 Option contracts may require an upfront cash investment.

2 Any ineffective portion is recorded in the Consolidated Statements 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.

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

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	-	-	-	-
Reporting date (marked-to-market)[2]	-	ü	ü	-
Settle contract	ü	ü	ü	ü

1 Option contracts may require an upfront cash investment.

2 Any ineffective portion is recorded in the Consolidated Statements 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, 2009.

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 Canadian GAAP as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, therefore fair value is 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. Where commodity transactions extend into periods for which market-observable prices are not available, an internally developed fundamental price forecast is used in the valuation. Fair values are validated by using reasonable possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2010, Level III instruments had a net liability carrying value of $20 million.

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 Consolidated Statements of Earnings and Retained 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 can be used to hedge exposure to changes in the carrying values of our net investments in foreign operations having 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.

Foreign exchange gains or losses related to net investment hedges are recorded in OCI until there is a permanent reduction in the net investment of the foreign operation. If there is a permanent reduction in the net investment of the foreign operation, the foreign exchange gains or losses previously recorded in OCI are transferred to net earnings in that period.

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

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract	-	-	-	-
Reporting date (marked-to-market)	-	ü	ü	-
Roll-over into new contract	-	ü	ü	ü
Settle contract	-	ü	ü	ü
Reduction of net investment of foreign operation	ü	ü	ü	-

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 Consolidated Statements of Earnings as they either do not qualify for, or have not been designated for, hedge accounting.

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

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	-	-	ü	-
Reporting date (marked-to-market)	ü	-	ü	-
Roll-over into new contract	ü	-	ü	ü
Settle contract	ü	-	ü	ü
Divest contract	ü	-	ü	ü

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.

Under the terms of our Stock Option Plans, employees below manager level receive grants that vest in equal installments over four years, and expire after 10 years. The conversion of these options does not materially affect the calculation of the total weighted average number of common shares outstanding.

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 comparator group. After three years, once PSOP eligibility has been determined and if common shares are granted, 50 per cent of the common shares are released to the participant and the remaining 50 per cent are held in trust for one additional year for employees below vice president level, and for two additional years for employees at the vice president level and above. The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below senior manager 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, 2010, accounts receivable from employees under the plan totalled $2 million (2009 - $3 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 for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2010.

We provide other health and dental benefits to the age of 65 for both disabled members and retired members (other post-retirement benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2010.

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 $62 million to secure the obligations under the supplemental plan.

Statements of Cash Flows

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2010 and 2009:

Year ended Dec. 31	**2010**	2009	Explanation of change
Cash and cash equivalents, beginning of year	**82**	50	
Provided by (used in):			
Operating activities	**811**	580	Higher cash earnings of $54 million and favourable changes in working capital of $177 million due to the timing of operational payments, favourable inventory movements, and the timing of certain tax-related recoveries.
Investing activities	**(720)**	(1,598)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million in 2009 and a decrease in 2010 capital spending of $114 million, partially offset by a decrease in collateral received from counterparties of $40 million.
Financing activities	**(113)**	1,053	Increase of $818 million in proceeds from the issuance of long-term debt and $397 million from the issuance of common shares in 2009, and a net increase in the repayment of debt of $255 million, partially offset by proceeds of $291 million from the issuance of preferred shares in 2010.
Translation of foreign currency cash	**(2)**	(3)	
Cash and cash equivalents, end of year	**58**	82	

Year ended Dec. 31	2009	2008	Explanation of change
Cash and cash equivalents, beginning of year	50	51	
Provided by (used in):			
Operating activities	580	1,038	Decrease in cash earnings of $99 million and unfavourable changes in working capital of $359 million.

Investing activities	(1,598)	(581)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million and the sale of our Mexican equity investment in 2008 for $332 million, partially offset by a decrease in capital spending of $102 million and an increase in collateral received from counterparties of $87 million.
Financing activities	1,053	(467)	Increase in draws on credit facilities of $863 million, increase in proceeds from the issuance of long-term debt of $617 million, increase in proceeds from the issuance of common shares of $382 million, and the purchase of common shares under the NCIB program in 2008 of $130 million, partially offset by a $488 million increase in the repayment of long-term debt.
Translation of foreign currency cash	(3)	9	
Cash and cash equivalents, end of year	82	50	

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

Debt

Recourse and non-recourse debt totalled $4.2 billion at Dec. 31, 2010 compared to $4.4 billion at Dec. 31, 2009. Total long-term debt decreased from Dec. 31, 2009 primarily due to the issuance of preferred shares and favourable foreign exchange movements, partially offset by growth capital expenditures.

Credit Facilities

At Dec. 31, 2010, we had a total of $2.0 billion (2009 - $2.1 billion) of committed credit facilities of which $1.1 billion (2009 - $0.7 billion) is not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2010, the $0.9 billion (2009 - $1.4 billion) of credit utilized under these facilities is comprised of actual drawings of $0.6 billion (2009 - $1.1 billion) and of letters of credit of $0.3 billion (2009 - $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2012, with the remainder comprised of bilateral credit facilities that mature between the fourth quarter of 2012 and the third quarter of 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $1.1 billion available under the credit facilities, we also have $58 million of cash.

Share Capital

At Dec. 31, 2010, we had 220.3 million (2009 - 218.4 million) common shares issued and outstanding. During the year ended Dec. 31, 2010, 1.9 million (2009 - 20.8 million) common shares were issued for $42 million (2009 - $408 million), of which $37 million (2009 - nil) was issued under the terms of the DRASP plan.

During the year ended and as at Dec. 31, 2010, 12.0 million (2009 - nil) first preferred shares were issued for $239 million (2009 - nil).

On Feb. 23, 2011, we had 221.2 million common shares and 12.0 million first preferred shares outstanding.

NCIB Program

For the year ended Dec. 31, 2010, no shares were acquired or cancelled under the NCIB program prior to its expiry on May 6, 2010. In 2009, no shares were acquired or cancelled under the NCIB program.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At Dec. 31, 2010, we provided letters of credit totalling $297 million (2009 - $334 million) and cash collateral of $27 million (2009 - $27 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Balance Sheets under risk management liabilities and asset retirement obligation.

Working Capital

At Dec. 31, 2010, the excess of current liabilities over current assets is $246 million (2009 - $10 million). The excess of current liabilities over current assets increased $236 million compared to 2009 due to an increase in the current portion of long-term debt and a decrease in collateral received from counterparties, partially offset by an increase in net risk management assets, lower operational expenditures and the timing of related payments, favourable inventory movements, and the timing of certain tax recoveries.

Capital Structure

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

	2010		2009	
As at Dec. 31	**Amount**	**%**	Amount	**%**
Debt, net of cash and cash equivalents	**4,177**	**54**	4,360	56
Non-controlling interests	**435**	**6**	478	6
Shareholders' equity	**3,177**	**41**	2,929	38
Total capital	**7,789**	**100**	7,767	100

Commitments

Contractual repayments of transmission, operating leases, commitments under mining agreements, commitments under long-term service agreements, long-term debt and the related interest, and growth project commitments are as follows:

	Fixed price gas purchase contracts	Transmission	Operating leases	Coal supply and mining agreements	Long-term service agreements	Long-term debt[1]	Interest on long-term debt[2]	Growth project commitments	Total
2011	8	1	14	55	19	253	237	106	693
2012	8	6	13	55	18	674	214	36	1,024
2013	9	7	12	55	17	629	194	-	923
2014	8	7	11	55	17	231	157	-	486
2015	8	7	10	60	9	681	127	-	902
2016 and thereafter	22	12	52	320	3	1,769	960	-	3,138
Total	**63**	**40**	**112**	**600**	**83**	**4,237**	**1,889**	**142**	**7,166**

1 *Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature between the fourth quarter of 2012 and the third quarter of 2013.*

2 *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 the Environment

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind and hydro, we also believe that coal and natural gas as fuels will continue to play an important role in meeting future energy needs. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low cost electricity.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our business.

Canada

On June 23, 2010, the Government of Canada announced plans to regulate GHG emissions from the coal-fired power sector. The proposal, if passed into law, would become effective in 2015 and require existing coal-fired plants to meet a natural gas emissions performance standard by their 45th year of operation, or the end of their PPA term, whichever is later. If the plants subject to the regulation do not meet the required performance standard by that time, they would be required to cease operations. Until then, the plants would not be subject to any federal GHG compliance costs.

The federal government continues with the drafting of the above regulations, and has stated its intention to release draft regulations by April 2011. The draft regulations would then be subject to consultations with provinces, industry, and the public. We are in discussions with both the Governments of Canada and Alberta about the design of the proposed regulation.

The above development would provide regulatory clarity for future capital decision-making. There are some issues that will have to be resolved, including how transition costs are recovered by generators, standards for emission requirements for natural gas-fired facilities, and how CCS will continue to be supported. The effect of this proposal on the Alberta deregulated market and PPA structure must also be considered.

Additionally, work has continued on the development of a national Clean Air Management System ("CAMS") for air pollutants. Development work is being done through collective efforts of federal and provincial governments, industry, and environmental organizations, with the goal of constructing an acceptable national structure for managing pollutants such as sulphur dioxide ("SO_2"), nitrogen oxide ("NOx") and particulates. Conceptually the system would establish baseline ambient air quality standards, industry emission standards, and mechanisms to address areas of non-compliance. It is expected that the CAMS model would default to provincial jurisdiction unless air quality problems remain unresolved. This process is expected to tak e several more years to complete. We are involved in the working groups. The impact of CAMS on our operations, if implemented, is not evident at this time.

In Ontario, the provincial government continues to develop its plans for a GHG regulatory framework consistent with the Western Climate Initiative ("WCI") model. The WCI model is a cap and trade design being developed jointly between several Canadian provinces and U.S. states, including California, to establish similar reduction targets and a common emissions trading market. Details of the Government of Ontario's proposed design have not yet been released.

In Alberta, mercury capture technology was installed by the end of the year and began operating at our coal-fired plants in order to achieve compliance with the Alberta requirement to reduce mercury emissions by 70 per cent by Jan. 1, 2011. To date, the mercury reduction requirements at these plants have been met.

In British Columbia, the provincial government is in the process of developing regulations for emissions trading and an offsets system under the *Greenhouse Gas Reduction (Cap and Trade) Act*. The system would be compatible with the WCI model. Consultations are underway regarding its design, with finalization of the regulations expected in 2011. Given our low-carbon operations in British Columbia, this regulatory initiative is not expected to have any material impact on the Corporation.

United States

In the absence of legislative action, the administration is moving to regulate greenhouse gases under the *Clean Air Act*. Under the "tailoring rule" adopted in 2010, on July 1, 2011, the Environmental Protection Agency ("EPA") will require new plants, or major modifications to existing plants, to acquire permits for GHGs. After that point, new or modified plants that otherwise would trigger major source preconstruction permit thresholds would be required to employ best

available technology to reduce their GHG emissions. The EPA began implementing these rules on Jan. 2, 2011. The definition of best available technology has not yet been determined. This EPA regulation is expected to face legal challenges as well as some opposition from Congress, and may be subject to further refinement in other rulemakings.

Further, at the end of December in 2010, the EPA stated its intentions to implement New Source Performance Standards for GHGs for power plants and refineries. These proposed regulations would cover emissions from both new and existing sources, and are expected to be completed by the end of 2012. The EPA does not expect existing sources would be affected until 2015 or 2016. These proposed regulations have not yet been developed so their impact is unclear. Again, this initiative is expected to face legal hurdles.

In Washington, we have been working with the state government to develop a plan to reduce GHG emissions from our Centralia Thermal plant, consistent with the Governor's Executive Order to reduce emissions by approximately 50 per cent of current levels by 2025. Discussions with Washington State and other stakeholders are ongoing.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form and within the Risk Management section of this MD&A, many of our activities and properties are subject to environmental requirements, as well as changes in our liabilities under these requirements, which may have a material adverse affect upon our consolidated financial results.

TransAlta Activities

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 expect that increased scrutiny will be placed on environmental emissions and compliance, and we therefore have a proactive approach to minimizing risks to our results.

In 2010, we estimate that 37 million tonnes of GHGs with an intensity of 0.976 tonnes per MWh (2009 - 36 million tonnes of GHGs with an intensity of 0.980 tonnes per MWh) were emitted as a result of normal operating activities[1]. Increased energy production from our fossil-based assets and the related increase in emissions were partially offset by the decommissioning of Unit 4 at our Wabamun plant, which represents a reduction of approximately two million tonnes per year of GHGs. 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 provides oversight to our environmental management programs and emission reduction initiatives in order to ensure continued compliance with environmental regulations.

Our environmental management programs encompass the following elements:

Renewable Power

In addition to our acquisition of Canadian Hydro, our investment in renewable power sources continues through the building or expansion of renewable power resources such as the Summerview 2, Kent Hills 2, and Ardenville wind farms. A larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or through offsets.

1 2010 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We have installed mercury control equipment at our Alberta Thermal operations in 2010 in order to meet the province's 70 per cent reduction objectives. Our new Keephills 3 plant will use supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at our Genesee 3 plant.

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

Policy Participation

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

CCS Development

On Oct. 14, 2009, the governments of Canada and Alberta announced that Project Pioneer, our CCS project, received funding commitments of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding supports a FEED study that is expected to be completed in 2011. Once built, the prototype plant will be one of the largest integrated CCS power facilities in the world. The project will be designed to capture one megatonne of carbon dioxide ("CO_2") per year from our new 450 MW (225 MW net ownership interest) Keephills 3 coal plant. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site. Additionally, on Nov. 28, 2010, Project Pioneer was awarded $5 million from the Global Carbon Capture and Storage Institute to enhance knowledge transfer from the project both nationally and globally.

In addition, we look to advance other clean energy technologies through organizations such as the Canadian Clean Coal Power Coalition which examines emerging clean combustion technologies such as gasification. We are also part of a group of companies participating in the Integrated CO_2 Network to develop carbon capture and storage systems and infrastructure for Canada.

Offsets Portfolio

TransAlta maintains an offset portfolio with a variety of instruments than can be used for compliance purposes or otherwise banked or sold. We continue to examine additional 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.

Forward Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward looking statements. All forward looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions, and expected further developments, as well

as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions, and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “anticipate”, “intend”, “plan”, “foresee”, “potential”, “enable”, “continue” or other comparable termi nology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

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

Factors that may adversely impact our forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) effects of weather; (viii) disruptions in the source of fuels, water, wind, or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) our provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel; (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of this MD&A and under the heading “Risk Factors” in our 2010 Annual Information Form.

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

2011 Outlook

In 2011, we anticipate modest comparable EPS growth based upon the factors that are discussed below.

Business Environment

Power Prices

In 2011, power prices are expected to remain at 2010 levels due to the influence of low natural gas prices. In the Alberta market, the longer-term fundamentals of the market remain positive and the recovery of the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices is the main driver behind any recovery of power prices. Natural gas prices are expected to remain low until 2012.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has expressed its plan to coordinate the timing and structure of its greenhouse gas regulatory framework with the U.S., although coal-fired power is being addressed separately and earlier. In the U.S., it is not clear if climate change legislation will prevail or if instead regulation will be applied by the EPA. Each of these outcomes could create widely different results for the energy industry in the U.S., and indirectly for Canada’s regulatory approach.

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

Economic Environment

The economic environment has shown signs of improvement in 2010 and we expect this trend to continue through 2011 at a slow to moderate pace.

We had no counterparty losses in 2010, and we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase in 2011 due to the start of commercial operations at Keephills 3 and Bone Creek. Overall production is expected to increase in 2011 due to the start of commercial operations at Keephills 3 and Bone Creek, lower planned and unplanned outages, and higher customer demand. Overall fleet availability is expected to be approximately 89 to 90 per cent in 2011 due to lower planned and unplanned outages.

Commodity Hedging

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis we target being up to 90 per cent contracted for the upcoming year, stepping down to 65 per cent in the fourth year. As at the end of 2010, approximately 88 per cent of our 2011 capacity was contracted. The average price of our short-term physical and financial contracts in 2011 ranges from $65-$70 per MWh in Alberta, and from U.S.$55-$60 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal

variations in coal costs at our Alberta mines are minimized through the application of standard costing. Coal costs for 2011, on a standard cost basis, are expected to be consistent with 2010.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2011 is expected to be consistent with 2010.

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

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

Operations, Maintenance, and Administration Costs

OM&A costs for 2011 are expected to be lower as a result of certain planned maintenance costs that had been expensed under Canadian GAAP being capitalized under International Financial Reporting Standards ("IFRS") in 2011, and lower OM&A costs related to our Poplar Creek base plant. In 2011, we will no longer operate the Poplar Creek base plant resulting in reduced OM&A expenditures and associated cost recoveries. The impact of no longer operating the Poplar Creek base plant is not expected to be significant to net earnings.

Energy Trading

Earnings from our Energy Trading segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2011 objective is for Energy Trading to contribute between $45 million and $65 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 denominated expenses, including interest charges, which largely offset our net foreign denominated revenues.

Net Interest Expense

Net interest expense for 2011 is expected to be higher than 2010 mainly due to higher debt balances, higher variable interest rates, lower capitalized interest, and lower interest income. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar will affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, there may be the need for additional liquidity in the future. To mitigate this liquidity risk, we expect to maintain $2.0 billion of committed credit facilities, and we will monitor our exposures and obligations to ensure we have sufficient liquidity to meet our requirements.

Accounting Estimates

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

Income Taxes

The effective tax rate for 2011 is expected to be approximately 17 to 22 per cent.

Capital Expenditures

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

Growth Capital Expenditures

In 2010, we spent a total of $470 million on growth capital expenditures, net of any joint venture contributions received. In 2010, we successfully commenced commercial operations at Summerview 2, Ardenville, and Kent Hills 2. We have five additional significant growth capital projects that are currently in progress with targeted completion dates between Q1 2011 and Q4 2012.

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

	Total Project		2010	2011	Target	
Project	Estimated spend	Spend to date[1]	Actual spend[1]	Estimated spend	completion date	Details
Keephills 3	988	928	221	50-60	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Keephills Unit 1 uprate	34	4	3	10-20	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Keephills Unit 2 uprate	34	6	5	20-30	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Bone Creek	48	54	50	-	Q1 2011	A 19 MW hydro facility in British Columbia
Sundance Unit 3 uprate	27	3	3	10-15	Q4 2012	A 15 MW efficiency uprate at our Sundance plant
Total growth expenditures	**1,131**	**995**	**282**	**90-125**		

1 Represents amounts spent as of Dec. 31, 2010. In 2010, we also spent a combined total of $188 million on Summerview 2, Ardenville, and Kent Hills 2.

Amounts disclosed in the above chart are shown net of any joint venture contributions received.

The total estimated spend for Bone Creek is less than the amount incurred to date due to the timing of project spend and estimated recoveries in 2011.

Sustaining Capital Expenditures

Certain costs related to planned maintenance that have been expensed under Canadian GAAP in 2010 will be capitalized under IFRS in 2011. Our estimate for total sustaining capital expenditures in 2011, net of any contributions received, is allocated among the following:

Category	Description	Spend in 2010	Expected cost
Routine capital	Expenditures to maintain our existing generating capacity	147	120-135
Productivity capital	Projects to improve power production efficiency	9	10-20
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	25	25-30
Planned maintenance	Regularly scheduled major maintenance	127	180-210
Total sustaining expenditures		**308**	**335-395**

Details of the 2011 planned maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected cost
Capitalized	105-130	75-80	180-210
Expensed	-	0-5	0-5
	105-130	75-85	175-200

	Coal	Gas and Renewables	Total
GWh lost	1,480-1,490	630-640	2,110-2,130

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing bank borrowing capacity, and capital markets. The funds required for committed growth and sustaining projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flow, our solid financial position, and the amount of capital available to us under existing committed credit facilities.

Related Party Transactions

On Jan. 1, 2009, TAU and TransAlta Energy Corporation transferred certain generation and transmission assets to a newly formed internal partnership, TAGP, before amalgamating with TransAlta Corporation.

On Dec. 16, 2006, predecessors of TAGP, a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Dec. 31, 2010, TAGP had received $61 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TA Cogen, which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). 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 two of its plants over the period of the swap. The notional gas volumes in the swap transactions are equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

Risk Management

Our business activities expose us to a variety of risks. Our goal is to manage these risks so that we are reasonably protected from an unacceptable level of earnings or financial exposure while still enabling business development. We use a multi-level risk management oversight structure to manage the risks arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface.

The responsibilities of 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 Toronto Stock Exchange corporate governance guidelines, and receives an annual comprehensive Enterprise Risk Management ("ERM") review. The ERM review consists of a holistic view of the Corporation's inherent risks, how we mitigate these risks, and residual risks. It defines our risks, discusses who is responsible to manage each risk, how the risks are inter-related with each other, and identifies the applicable risk metrics.

The Audit and Risk Committee ("ARC"), 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 and 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 ARC approves our Commodity and Financial Exposure Management policies and reviews quarterly ERM reporting.

The Exposure Management Committee ("EMC") is chaired by our Chief Financial Officer and is comprised of the Chief Operating Officer, Vice-President Controller and Treasurer, Vice-President Corporate Planning and Analysis, Vice-President Operations Finance, and Vice-President Internal Audit and Risk. The EMC is responsible for reviewing and monitoring compliance within approved financial and commodity exposure management policies.

The Technical Risk and Commercial Team ("TRACT") is a committee chaired by the Vice-President, Engineering, Environment, and Construction Services, and is comprised of our financial and operations vice presidents. It reviews major projects and commercial agreements at various stages through development, prior to submission for executive and Board approval.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to and respectful of our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exceptional approval process. Periodic reviews and audits are performed to ensure compliance with these policies.

Reporting

On a regular basis, risk exposures are reported to key decision makers including the Board of Directors, senior management, and the EMC. Reporting to the EMC includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion of actions to minimize risks. This monthly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a system in place where employees, shareholders, or other stakeholders may report any potential ethical concerns. These concerns can be submitted anonymously, either directly to the ARC or to the Director, 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 chair of the ARC.

Value at Risk and Trading Positions

VaR is the primary measure used to manage our exposure to market risk resulting from energy trading activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR at Dec. 31, 2010 associated with our proprietary energy trading activities was $5 million (2009 - $3 million).

VaR is a commonly used metric that is employed by industry to track the risk in energy trading positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed weekly to measure the financial impact to the trading portfolio resulting from potential market events including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. 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 of changes in certain key variables. The analysis is based on business conditions and production volumes in 2010. 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. For example, the financial performance of our hydro, wind, and geothermal operations are partially dependant upon the availability of their input resources in a given year. 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.

We manage these risks by:

- actively managing our assets and their condition through the Generation and Capital and Asset Reporting groups in order to be proactive in plant maintenance so that they are available to produce when required,
- monitoring water resources throughout Alberta and British Columbia to the best of our ability and optimizing this resource against real-time electricity market opportunities, and
- 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 our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require.

The sensitivities of volumes to our net earnings are shown below:

Approximate impact

Factor	Increase or decrease (%)	on net earnings
Availability/production	1	24

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse affect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. 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 may be required to 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 mater ial 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 where our equipment is 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 availability 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,
- adjusting maintenance plans by facility to reflect the equipment type and age,
- having sufficient business interruption coverage 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,
- entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts, 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 the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short- and long-term contracts to mitigate 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.

In 2010, we had approximately 95 per cent of production under short-term and long-term contracts and hedges (2009 - 97 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 the financial exposure to fluctuations in the costs of fuels used in production by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants, and
- selectively using hedges, where available, to set prices for fuel.

In 2010, 81 per cent (2009 - 79 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2009 - 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings are shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$1.00/MWh	8
Natural gas price	$0.10/GJ	1
Coal price	$1.00/tonne	14

Fuel Supply Risk

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities.

At our coal-fired plants, input costs, such as diesel, tires, the price of mining equipment, the volume of overburden removed to access coal reserves, and the location of mining operations relative to the power plants are some of the exposures in our mining operations. 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 coal 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, 2010, approximately 75 per cent (2009 - 75 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,

- contracting sufficient trains to deliver the coal requirements at Centralia Thermal,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,
- monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants, and
- hedging diesel exposure in mining and transportation costs.

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 existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the U.S. 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 compliance 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 management system in place that is designed to continuously improve environmental performance,
- committing significant effort to work with regulators in Canada and the U.S. to ensure regulatory changes are well designed and cost effective,
- developing compliance plans that address how to meet or exceed emission standards for GHGs, mercury, SO_2, 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 and hydro generation, and
- investing in clean coal technology development, which potentially 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 2010, we spent approximately $55 million (2009 - $45 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 assess and develop clean combustion technologies. On Oct. 14, 2009, the federal and provincial governments announced that Project Pioneer, our CCS project, has received committed funding of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative.

In October 2010, the Canadian Securities Administrators ("CSA") published guidance on environmental disclosure in Staff Notice 51-333. The guidance directs issuers to address:

- environmental risks and related matters,
- environmental risk oversight and management,
- forward-looking information requirements as they relate to environmental goals and targets, and
- the impact of the adoption of IFRS on disclosure of environmental liabilities.

TransAlta has reviewed this guidance and believe that we comply with these requirements.

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 or performance 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 net earnings and cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits, and the credit concentration with any specific counterparty,
- 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.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2009. We had no counterparty losses in 2010, and 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. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

A summary of our credit exposure for our energy trading operations and hedging activities at Dec. 31, 2010 is provided below:

Counterparty credit rating	Net exposure
Investment grade	349

Non-investment grade	-
No external rating, internally rated as investment grade	26
No external rating, internally rated as non-investment grade	1

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 $43 million (2009 - $63 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, the acquisition of equipment and services from foreign suppliers, and our U.S. denominated debt. Our exposures are 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 or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that include:

- 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 such foreign currency exposures. At Dec. 31, 2010, we have hedged approximately 95 per cent (2009 - 97 per cent) of our foreign currency net investment exposure,
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure, and
- entering into forward foreign exchange contracts to hedge future foreign denominated receipts and expenditures, and all U.S. denominated debt outside of our net investment portfolio.

Translation gains and losses related to the carrying value of our foreign operations and any hedges in respect thereof are included in AOCI in shareholders' equity until such a time there is a permanent reduction in our investment.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that a six cent increase or decrease in the U.S. or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.06	3

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for energy trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide a more reliable and cost-effective means to access capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

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 energy trading activities on a regular basis to the EMC, senior management, and Board of Directors,
- maintaining investment grade credit ratings, and
- maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

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 establishing and adhering to policies that include:

- 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, 2010, approximately 25 per cent (2009 - 31 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 net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	1	10

Project Management Risk

As we are currently working on five 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 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 senior management and Board of Directors 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 Capital Power 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,
- managing 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.

In 2010, 46 per cent (2009 - 46 per cent) of our labour force is covered by 11 (2009 - 11) collective bargaining agreements. In 2010, four (2009 - five) agreements were renegotiated. We anticipate negotiating three agreements in 2011. 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. 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 insurance.

Transmission Risk

Access to transmission lines and sufficient capacity of those transmission lines are key in our ability to deliver energy produced at our power plants to our customers. However, with the continued growth in demand for electricity coupled with very little transmission capacity being added, and the reduced reliability and available capacity on the existing transmission facilities, the risks associated with the aging existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continue to increase.

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 Director, 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 chair of the ARC. 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, financing costs, 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 Canadian GAAP, based on all information currently available.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	2

The effective tax rate on comparable earnings before income taxes for 2010 was 16 per cent. The effective income tax rate can change depending on the mix of earnings from various countries and certain deductions that do not fluctuate with earnings.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings that 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 2010. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

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, financial instruments and hedges, PP&E, goodwill, income taxes, employee future benefits, and asset retirement obligation. Each policy involves a number of estimates and assumptions to be made about matters that are 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 ARC and our independent auditors. The ARC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

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 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.

Energy trading activities use derivatives such as physical and financial swaps, forward sales contracts, and futures contracts and options, 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 Consolidated Statements of Earnings when hedge accounting is not applied. 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 Consolidated 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 AOCI and are presented on the Consolidated Balance Sheets as risk managem ent 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 are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal 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 fair values, the Corporation uses quoted prices for identically traded commodities obtained from active

exchanges such as the New York Mercantile Exchange.

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.

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.

Level III

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

In limited circumstances, we 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. Where commodity transactions extend into periods for which market-observable prices are not available, an internally developed fundamental price forecast is used in the valuation.

As a result of the acquisition of Canadian Hydro, we also have various contracts with terms that extend beyond five years. Valuation of these contracts must be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

The effect of using reasonable possible alternative assumptions as inputs to valuation techniques from which the Level III fair values are determined at Dec. 31, 2010 is estimated to be +/- $14 million (2009 - +/- $24 million). This estimate is based on a +/- one standard deviation move from the mean where historical data is used in the valuation. Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate.

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2010, 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 and associated contracts are recoverable from future undiscounted cash flows. Factors that 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 com plicated 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 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 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 flow s related to the asset. Both the identification of events that may trigger 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, retirement costs, and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any changes 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 more frequently if events indicate, we perform an impairment review of our plants. As a result of this review in 2010, pre-tax asset impairment charges of $89 million were recorded related to certain natural gas and coal facilities. Refer to the Asset Impairment section of this MD&A for further details.

Project Development Costs

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.

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives are 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. These estimates are subject to revision in future periods based on new or additional information. 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.

In 2010, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $490 million (2009 - $493 million), of which $42 million

(2009 - $40 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.

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 Canadian Hydro, Merchant Energy Group of the Americas, Inc., Vision Quest Windelectric Inc., and CE Gen. At Dec. 31, 2010, this goodwill had a total carrying value of $517 million (2009 - $434 million). The change in value from Dec. 31, 2009 is primarily due to the Canadian Hydro purchase price allocation adjustment.

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, 2010. Accordingly, no goodwill impairment charges were recorded for the year ended Dec. 31, 2010.

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 $240 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2010 (2009 - $234 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 $707 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2010 (2009 - $707 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 in accordance with Canadian GAAP based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated 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 to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

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, 2010, the plan assets had a positive return of $28 million, compared to $38 million in 2009, and a negative return of $55 million in 2008. The 2010 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2009 and 2008.

Asset Retirement Obligation

We recognize AROs 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 AROs. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

At Dec. 31, 2010, the ARO recorded on the Consolidated Balance Sheets was $242 million (2009 - $282 million). We estimate the undiscounted amount of cash flow required to settle the ARO is approximately $0.8 billion, which will be incurred between 2011 and 2072. The majority of these costs will be incurred between 2020 and 2050. The average discount used to calculate the carrying value of the ARO was eight per cent.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	2
Undiscounted ARO	1	-

Future Accounting Changes

IFRS Convergence

On Jan. 1, 2011, we adopted IFRS for publicly accountable enterprises as required by the Accounting Standards Board. Our project to convert to IFRS consisted of the following phases:

Phase	Description	Status
Diagnostic	In-depth identification and analysis of differences between Canadian GAAP and IFRS	Complete
Design and planning	Cross-functional, issue-specific teams analyze the key areas of convergence, and along with Information Technology and Internal Control resources, determine process, system, and financial reporting controls changes required for the conversion to IFRS	Complete
Solution development	Plans to address identified conversion issues are developed and tested in a controlled environment. Staff training programs and internal communication plans are implemented to communicate process changes as a result of the conversion to IFRS	Complete
Implementation	Processes required for dual reporting in 2010 and full convergence in 2011 are implemented in a live environment with change management in place for a successful transition to steady state	Complete

A steering committee continues to monitor the progress of the transition to IFRS and will continue to meet regularly until our March 31, 2011 first interim report under IFRS is completed. 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.

While IFRS uses a conceptual framework similar to Canadian GAAP and has many similarities to Canadian GAAP, there are several significant differences in accounting policies that have been addressed as part of our conversion project. Overall, these differences are expected to have a relatively modest impact on our consolidated financial results. The more significant impacts of IFRS to us are as follows:

PP&E

- *Key change in accounting:* Major inspection costs, which are currently expensed, will be capitalized and depreciated over the period until the next major inspection.
- *Income statement impact:* Earnings will likely be less volatile.
- *Balance sheet impact upon transition to IFRS:* Net increase in PP&E of $115 million as previously expensed major inspection costs will be capitalized.
- *Cash flow statement impact:* Major inspection costs will be recorded as cash flows used in investing activities instead of as cash flows used in operating activities.
- *Other differences:* Additional disclosures reconciling the changes in cost and accumulated depreciation for individual classes of PP&E will be required.

Employee Benefits

- *Key change in accounting:* All actuarial gains and losses related to defined benefit plans will be recognized in other comprehensive income.
- *Income statement impact:* Expenses associated with defined benefit plans will differ. The impact on net earnings is not expected to be significant.
- *Balance sheet impact upon transition to IFRS:* Recognition of net cumulative actuarial losses of $78 million (after-tax) in opening retained earnings.
- *Cash flow statement impact:* None.

Joint Arrangements

- *Key change in accounting:* Interests in joint ventures classified as jointly controlled entities can be recognized using either the proportionate consolidation or equity method. We have chosen to account for these entities using the equity method instead of the proportional consolidation method as required by Canadian GAAP. Prior to March 31, 2011, the International Accounting Standards Board is expected to issue a new standard on the accounting for joint ventures that eliminates the option of proportionate consolidation. The new standard is expected to come into effect Jan. 1, 2013, with early adoption permitted. If we decide to early adopt this new standard effective Jan. 1, 2011, no additional changes are expected.
- *Income statement impact:* Revenues and expenses will be recorded as equity earnings or loss, a single line item on the Consolidated Statement of Earnings. There is no impact on net earnings.
- *Balance sheet impact upon transition to IFRS:* Our share of assets and liabilities will be removed from the various line items on the Statement of Financial Position and the corresponding net amount of $202 million will be recorded as an investment.
- *Cash flow statement impact:* Our proportionate share of cash from equity accounted joint ventures will not be reflected on the Consolidated Statement of Cash Flow. Only contributions to and distributions from investments accounted for using the equity method will be reflected in the cash flow statement as an investing activity.

Provisions, Contingent Liabilities, and Contingent Assets

- *Key change in accounting:* AROs are revalued at the end of each quarterly and annual reporting period using current market-based interest rates instead of using historic rates.

- *Income statement impact:* Accretion expense will be classified as a finance (interest) cost under IFRS as opposed to an operating expense under Canadian GAAP, and may fluctuate more often due to the impact of the period-end revaluations.
- *Balance sheet impact upon transition to IFRS:* Due to differences in discount rates, the opening balance of the provisions for ARO will increase by $34 million.
- *Cash flow statement impact:* None.

Arrangements Containing a Lease

- *Key change in accounting:* All contractual arrangements will be evaluated to determine if they contain a finance or operating lease.
- *Income statement impact:* For those contracts that are determined to be finance leases, a portion of payments received under the contract will be recorded as finance (interest) income. For those contracts that are determined to be operating leases, the timing of recognition of revenue may differ. The impact on net earnings in either case is not expected to be significant.
- *Balance sheet impact upon transition to IFRS:* For certain long-term contracts that are deemed to be finance leases, the associated PP&E of $30 million will be removed from the Consolidated Balance Sheets and replaced with a long-term receivable of $50 million, representing the present value of lease payments to be received over the life of the contract.
- *Cash flow statement impact:* Payments received under the contract for finance leases will be recorded as cash flows from financing activities instead of cash flows from operating activities.

Asset Impairment

- *Key change in accounting:* Asset impairment testing no longer utilizes undiscounted future cash flows to initially assess for impairment. Instead, an asset's carried amount is compared to the greater of its value in use or fair value less normal costs to sell. Asset impairment charges can be reversed if the conditions creating the impairment reverse.
- *Income statement impact:* Depreciation expense for any impaired assets will be lower over the useful life of the asset.
- *Balance sheet impact upon transition to IFRS:* Impairment charges of $98 million will reduce PP&E, opening retained earnings, and non-controlling interests, as well as increase provisions.
- *Cash flow statement impact:* None.

A number of elections were available to us under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* that assisted with our transition to IFRS. We have made use of several of these elections as follows:

- Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax, of $63 million, will be reset to zero;
- Share-based payment guidance under IFRS will only be applied to equity instruments outstanding at transition that were granted on or after Nov. 7, 2002, and which had not vested by the transition date;
- Business combinations that occurred prior to Jan. 1, 2010 will continue to be measured and recorded at the Canadian GAAP amounts;
- We will use a simplified method to recalculate the cost of decommissioning assets included in PP&E; and
- We will not adjust interest previously capitalized as part of PP&E under Canadian GAAP.

In addition, various presentation changes are required under IFRS that have no impact on opening retained earnings.

Non-GAAP Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under Canadian GAAP and therefore should not be considered in isolation or as an alternative to or to be more meaningful than net earnings or cash flow from operating activities, as determined in accordance with Canadian GAAP, 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 applicable to common shares below:

Year ended Dec. 31	**2010**	2009	2008
Revenues	**2,819**	2,770	3,110
Fuel and purchased power	**1,202**	1,228	1,493
Gross margin	**1,617**	1,542	1,617
Operations, maintenance, and administration	**634**	667	637
Depreciation and amortization	**459**	475	428
Taxes, other than income taxes	**27**	22	19
Operating expenses	**1,120**	1,164	1,084
Operating income	**497**	378	533
Foreign exchange gain (loss)	**10**	8	(12)
Asset impairment charges	**(89)**	(16)	-
Net interest expense	**(178)**	(144)	(110)
Other income	**-**	8	5
Equity loss	**-**	-	(97)
Earnings before non-controlling interests and income taxes	**240**	234	319
Non-controlling interests	**20**	38	61
Earnings before income taxes	**220**	196	258
Income tax expense	**1**	15	23
Net earnings	**219**	181	235
Preferred share dividends	**1**	-	-

Net earnings applicable to common shares	**218**	181	235

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with results from prior periods. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the year.

In calculating comparable earnings for 2010, we excluded asset impairment charges, as well as unrealized gains related to certain power hedging relationships deemed ineffective for accounting purposes, as these transactions are unusual in nature and have not historically been a normal occurrence in the course of operating our business. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in comparable earnings in the period that they settle, the majority of which will settle during the second quarter of 2011. In addition, we excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

In calculating comparable earnings for 2009, we have excluded asset impairment charges, the impact of a future tax rate change, and the settlement of an outstanding commercial issue that has been recorded in other income as this was related to our previously held Mexican equity investment.

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

In calculating comparable earnings for 2008, we excluded the impact recoveries related to certain tax positions as they do not relate to the earnings in the period in which they have been reported. We also excluded the gains recorded on the sale of assets at the previously operated Centralia coal mine in 2008 as we do not normally dispose of large quantities of fixed assets. We have also excluded the writedown of our Mexican equity investment.

Earnings on a comparable basis are reconciled to net earnings applicable to common shares below:

Year ended Dec. 31	**2010**	2009	2008
Net earnings applicable to common shares	**218**	181	235
Asset impairment charges, net of tax	**54**	10	**-**
Unrealized gains related to ineffectiveness in certain power hedging relationships, net of tax	**(28)**	**-**	**-**
Income tax recovery related to the resolution of certain outstanding tax matters	**(30)**	**-**	**-**
Gain on sale of assets at Centralia, net of tax	**-**	**-**	(4)
Change in life of Centralia parts, net of tax	**-**	1	(12)
Settlement of commercial issue, net of tax	**-**	(6)	**-**
Tax rate change	**-**	(5)	**-**
Recovery related to tax positions	**-**	**-**	(15)
Writedown of Mexican equity investment, net of tax	**-**	**-**	62
Earnings on a comparable basis	**214**	181	290
Weighted average number of common shares outstanding in the year	**219**	201	199
Earnings on a comparable basis per share	**0.98**	0.90	1.46

Comparable EBITDA

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

Year ended Dec. 31	**2010**	2009	2008
Operating income	**497**	378	533
Asset retirement obligation accretion per the Consolidated Statements of Cash Flows	**21**	24	22
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**490**	493	451
EBITDA	**1,008**	895	1,006
Unrealized gains related to ineffectiveness in certain power hedging relationships, pre-tax	**(43)**	**-**	**-**
Settlement of commercial issue, pre-tax	**-**	(7)	**-**
Comparable EBITDA	**965**	888	1,006

1 To calculate comparable EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows because it takes into account depreciation related to mine assets, which is included in cost of sales per the Consolidated Statements of Earnings.

Funds from Operations and Cash Flow from Operating Activities per Share

Presenting funds from operations and cash flow from operating activities from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before and after changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with prior periods. Cash flow from operating activities per share is calculated using the weighted average common shares outstanding during the period.

	2010	2009	2008
Funds from operations	**783**	729	828
Change in non-cash operating working capital balances	**28**	(149)	210
Cash flow from operating activities	**811**	580	1,038
Weighted average number of common shares outstanding in the year	**219**	201	199
Cash flow from operating activities per share	**3.70**	2.89	5.22

Free Cash Flow (Deficiency)

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

Sustaining capital expenditures for the year ended Dec. 31, 2010, represents total additions to PP&E per the Consolidated Statements of Cash Flows less $482 million ($470 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2009, we invested $524 million ($510 million net of joint venture contributions). In 2008, we invested $541 million ($515 million net of joint venture contributions).

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

Year ended Dec. 31	**2010**	2009	2008
Cash flow from operating activities	**811**	580	1,038
Add (deduct):			
Sustaining capital expenditures	**(308)**	(380)	(465)
Cash dividends paid on common shares	**(216)**	(226)	(212)
Distribution to subsidiaries' non-controlling interests	**(62)**	(58)	(98)
Non-recourse debt repayments[1]	**(21)**	(25)	(28)
Other income	**-**	(8)	**-**
Timing of contractually scheduled payments	**-**	**-**	(116)
Cash flows from equity investments	**-**	**-**	2
Free cash flow (deficiency)	**204**	(117)	121

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

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

Comparable ROCE

Comparable ROCE measures the efficiency and profitability of capital investments and is calculated by taking comparable earnings before net interest expense, non-controlling interests, and income taxes, and dividing by the average invested capital excluding AOCI. 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 ROCE is presented below:

Year ended Dec. 31	**2010**	2009	2008
Earnings before income taxes per the Consolidated Statements of Earnings	**220**	196	258
Net interest expense	**178**	144	110
Non-controlling interests	**20**	38	61
Non-comparable items			
Asset impairment charges, pre-tax	**89**	16	**-**
Unrealized gains related to ineffectiveness in certain power hedging relationships, pre-tax	**(43)**	**-**	**-**
Change in life of Centralia parts, pre-tax	**-**	2	18
Settlement of commercial issue, pre-tax	**-**	(7)	**-**
Writedown of Mexican equity investment, pre-tax	**-**	**-**	97
Gain on sale of assets at Centralia, pre-tax	**-**	**-**	(6)
Comparable earnings before net interest expense, non-controlling interests, and income taxes	**464**	389	538
Average invested capital excluding AOCI	**7,645**	6,659	5,588
Comparable ROCE	**6.1**	5.8	9.6

Selected Quarterly Information

	Q1 2010	**Q2 2010**	**Q3 2010**	**Q4 2010**
Revenues	**726**	**582**	**700**	**811**
Net earnings applicable to common shares	**67**	**51**	**38**	**62**
Basic and diluted earnings per common share	**0.31**	**0.23**	**0.17**	**0.28**
Comparable earnings per common share	**0.31**	**0.10**	**0.17**	**0.40**

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Revenues	756	585	666	763
Net earnings (loss) applicable to common shares	42	(6)	66	79
Basic and diluted earnings (loss) per common share	0.21	(0.03)	0.34	0.37
Comparable earnings (loss) per common share	0.18	(0.03)	0.34	0.40

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

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 comm unicated 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, our 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, 2010, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

TransAlta Consolidated Financial Statements

December 31, 2010

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 carries out its responsibilities principally through its Audit and Risk Committee ("the 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 Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.



Stephen G. Snyder
President & Chief Executive Officer



Brett Gellner
Chief Financial Officer

February 23, 2011

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 proportionately consolidates the accounts of the Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures 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 2010 consolidated financial statements of TransAlta Corporation included $1,454 million and $804 million of total and net assets, respectively, as of Dec. 31, 2010, and $344 million and $64 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, 2010, 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, 2010, 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 the following page of this Annual Report.



Stephen G. Snyder
President & Chief Executive Officer



Brett Gellner
Chief Financial Officer

February 23, 2011

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, 2010, 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 Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures, which are included in the 2010 consolidated financial statements of the Corporation and constituted $1,454 million and $804 million of total and net assets, respectively, as of December 31, 2010, and $344 million and $64 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 Sheerness, CE Generation, 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, 2010, 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, 2010 and 2009 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, 2010, and our report dated February 23, 2011, expressed an unqualified opinion thereon.



Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2011

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, 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, 2010, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated 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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2011 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.



Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2011

Consolidated Statements of Earnings and Retained Earnings

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2010**	2009	2008
Revenues	**2,819**	2,770	3,110
Fuel and purchased power	**1,202**	1,228	1,493
	1,617	1,542	1,617
Operations, maintenance, and administration	**634**	667	637
Depreciation and amortization	**459**	475	428
Taxes, other than income taxes	**27**	22	19
	1,120	1,164	1,084
	497	378	533
Foreign exchange gain (loss) *(Note 8)*	**10**	8	(12)
Asset impairment charges *(Note 3)*	**(89)**	(16)	-
Net interest expense *(Notes 8 and 17)*	**(178)**	(144)	(110)
Equity loss *(Note 24)*	**-**	-	(97)
Other income *(Note 4)*	**-**	8	5
Earnings before non-controlling interests and income taxes	**240**	234	319
Non-controlling interests *(Note 5)*	**20**	38	61
Earnings before income taxes	**220**	196	258
Income tax expense *(Note 6)*	**1**	15	23
Net earnings	**219**	181	235
Preferred share dividends *(Note 21)*	**1**	-	-
Net earnings applicable to common shares	**218**	181	235
Retained earnings			
Opening balance	**634**	688	763
Common share dividends *(Note 20)*	**(319)**	(235)	(215)
Shares cancelled under NCIB *(Note 20)*	**-**	-	(95)

Closing balance	**533**	634	688
Weighted average number of common shares outstanding in the year	**219**	201	199
Net earnings per common share, basic and diluted *(Note 20)*	**1.00**	0.90	1.18

See accompanying notes.

Consolidated Balance Sheets

Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009
		(Note 2)
Cash and cash equivalents *(Notes 7 and 24)*	**58**	82
Accounts receivable *(Notes 7, 9, 24, and 28)*	**428**	421
Collateral paid *(Notes 7 and 8)*	**27**	27
Prepaid expenses *(Note 24)*	**10**	18
Risk management assets *(Notes 7 and 8)*	**265**	144
Income taxes receivable	**19**	39
Inventory *(Note 10)*	**53**	90
	860	821
Long-term receivable *(Notes 7 and 11)*	**-**	49
Property, plant, and equipment *(Notes 12, 24, and 29)*		
Cost	**11,706**	11,701
Accumulated depreciation	**(4,129)**	(4,142)
	7,577	7,559
Assets held for sale *(Note 13)*	**60**	-
Goodwill *(Notes 14, 24, and 29)*	**517**	434
Intangible assets *(Notes 15 and 24)*	**304**	344
Future income tax assets *(Note 6)*	**240**	234
Risk management assets *(Notes 7 and 8)*	**208**	224
Other assets *(Notes 16 and 24)*	**127**	121
Total assets	**9,893**	9,786
Short-term debt *(Note 7)*	**1**	-
Accounts payable and accrued liabilities *(Notes 7 and 24)*	**503**	521
Collateral received *(Notes 7 and 8)*	**126**	86
Risk management liabilities *(Notes 7, 8, and 24)*	**35**	45
Income taxes payable	**8**	10
Future income tax liabilities *(Note 6)*	**77**	45
Dividends payable *(Note 7)*	**130**	61
Current portion of long-term debt - recourse *(Notes 7 and 17)*	**235**	7
Current portion of long-term debt - non-recourse *(Notes 7 and 17)*	**20**	24
Current portion of asset retirement obligation *(Note 18)*	**38**	32
	1,173	831
Long-term debt - recourse *(Notes 7 and 17)*	**3,450**	3,857
Long-term debt - non-recourse *(Notes 7, 17, and 24)*	**529**	554
Asset retirement obligation *(Notes 18 and 24)*	**204**	250
Liabilities held for sale *(Note 13)*	**3**	-
Deferred credits and other long-term liabilities *(Note 19)*	**169**	147
Future income tax liabilities *(Notes 6 and 24)*	**630**	662
Risk management liabilities *(Notes 7, 8, and 24)*	**123**	78
Non-controlling interests *(Note 5)*	**435**	478
Shareholders' equity		
Common shares *(Notes 20 and 22)*	**2,211**	2,169
Preferred shares *(Notes 21 and 22)*	**293**	-
Retained earnings *(Note 22)*	**533**	634
Accumulated other comprehensive income *(Note 22)*	**140**	126
Total shareholders' equity	**3,177**	2,929
Total liabilities and shareholders' equity	**9,893**	9,786

Contingencies *(Notes 26 and 28)*

Commitments *(Notes 7 and 27)*

Subsequent events *(Note 34)*

See accompanying notes.

On behalf of the Board:



Donna Soble Kaufman
Director



William D. Anderson
Director

Consolidated Statements of Comprehensive Income

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009	2008
Net earnings	**219**	181	235
Other comprehensive income			
(Losses) gains on translating net assets of self-sustaining foreign operations	**(60)**	(209)	342
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax[1]	**33**	140	(295)
Gains on derivatives designated as cash flow hedges, net of tax[2]	**164**	280	198
Loss on sale of Mexico equity investment reclassified to the Consolidated Statements of Earnings, net of tax[3] *(Note 24)*	**-**	-	(8)
Reclassification of losses (gains) on derivatives designated as cash flow hedges to the Consolidated Balance Sheets, net of tax[4]	**8**	(11)	8
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax[5]	**(129)**	(135)	61
Reclassification of gains on translation of self-sustaining foreign operations to net earnings, net of tax[6]	**(2)**	-	-
Other comprehensive income	**14**	65	306
Comprehensive income	**233**	246	541

1 Net of income tax expense of 6 for the year ended Dec. 31, 2010 (2009 - 26 expense, 2008 - 61 recovery).
2 Net of income tax expense of 87 for the year ended Dec. 31, 2010 (2009 - 120 expense, 2008 - 129 expense).
3 Net of income tax expense of 9 for the year ended Dec. 31, 2008.
4 Net of income tax recovery of 3 for the year ended Dec. 31, 2010 (2009 - 4 expense, 2008 - nil).
5 Net of income tax expense of 65 for the year ended Dec. 31, 2010 (2009 - 69 expense, 2008 - 30 recovery).
6 Net of income tax expense of 3 for the year ended Dec. 31, 2010.

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009	2008
Operating activities			
Net earnings	**219**	181	235
Depreciation and amortization *(Note 29)*	**490**	493	451
Gain on sale of equipment	**(4)**	-	(5)
Non-controlling interests *(Note 5)*	**20**	38	61
Asset retirement obligation accretion *(Note 18)*	**21**	24	22
Asset retirement costs settled *(Note 18)*	**(37)**	(35)	(37)
Future income taxes *(Note 6)*	**28**	21	1
Unrealized (gain) loss from risk management activities	**(47)**	2	12
Unrealized foreign exchange gain	**(5)**	(11)	(5)
Asset impairment charges *(Note 3)*	**89**	16	-
Equity loss *(Note 24)*	**-**	-	97
Other non-cash items	**9**	-	(4)
	783	729	828
Change in non-cash operating working capital balances *(Note 30)*	**28**	(149)	210
Cash flow from operating activities	**811**	580	1,038
Investing activities			
Acquisition of Canadian Hydro Developers, Inc., net of cash acquired *(Note 24)*	**-**	(766)	-
Additions to property, plant, and equipment *(Note 12)*	**(790)**	(904)	(1,006)
Proceeds on sale of property, plant, and equipment	**6**	7	30
Proceeds on sale of minority interest in Kent Hills *(Notes 4 and 5)*	**15**	29	-
Restricted cash	**-**	-	248
Resolution of certain tax matters *(Note 11)*	**29**	(41)	(8)
Realized (losses) gains on financial instruments	**(29)**	(16)	52
Loan to equity investment	**-**	-	(245)
Proceeds on sale of equity investment *(Note 24)*	**-**	-	332
Net increase in collateral received from counterparties	**47**	87	-
Net (increase) decrease in collateral paid to counterparties	**(2)**	7	-
Settlement of adjustments on sale of Mexican equity investment	**-**	(7)	-
Other	**4**	6	16
Cash flow used in investing activities	**(720)**	(1,598)	(581)
Financing activities			
Net (decrease) increase in borrowings under credit facilities *(Note 17)*	**(400)**	620	(243)
Repayment of long-term debt *(Note 17)*	**(31)**	(796)	(308)
Issuance of long-term debt *(Note 17)*	**301**	1,119	502
Dividends paid on common shares	**(216)**	(226)	(212)
Funds paid to repurchase common shares under NCIB *(Note 20)*	**-**	-	(130)
Net proceeds on issuance of common shares *(Note 20)*	**1**	398	15
Net proceeds on issuance of preferred shares *(Note 21)*	**291**	-	-
Realized gains on financial instruments	**3**	-	12
Distributions paid to subsidiaries' non-controlling interests *(Note 5)*	**(62)**	(58)	(98)

Other	-	(4)	(5)
Cash flow (used in) from financing activities	**(113)**	1,053	(467)
Cash flow (used in) from operating, investing, and financing activities	**(22)**	35	(10)
Effect of translation on foreign currency cash	**(2)**	(3)	9
(Decrease) increase in cash and cash equivalents	**(24)**	32	(1)
Cash and cash equivalents, beginning of year	**82**	50	51
Cash and cash equivalents, end of year	**58**	82	50
Cash taxes (recovered) paid	**(49)**	43	47
Cash interest paid	**153**	149	106

See accompanying notes.

Notes to 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 three reportable segments.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation segment owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("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.

II. Energy Trading[1]

The Energy Trading segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

Energy Trading 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 and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of all of these activities are included in the Generation segment.

III. Corporate

The Corporate segment 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 to the Generation and Energy Trading groups.

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 consolidated 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 consolidated financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Actual results could differ from 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.

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 Consolidated Statements of Earnings. The initial recognition of

1 *The Energy Trading segment was referred to as "Commercial Operations and Development" in 2009 and 2008.*

fair value and subsequent changes in fair value affect reported net 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 Consolidated Balance Sheets as risk management assets or liabilities.

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

E. 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. The amounts previously recognized in AOCI are recognized in net earnings when there is a permanent reduction in the hedged net investment as a result of a dilution or sale of the net investment.

Transactions denominated in a currency other than the functional currency are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

F. 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 from the point when the Corporation becomes a party to the contract. Financial liabilities are removed from the consolidated 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 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 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. In order to manage the ratio of floating rate versus fixed rate debt, the Corporation uses interest rate swaps as fair value or cash flow hedges. To hedge exposures to anticipated changes in interest rates for forecasted issuances of debt, the Corporation uses interest rate swaps as cash flow hedges. For cash flow hedges, the Corporation primarily uses physical and financial swaps, forward 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 exposure s 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 denominated debt.

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 Consolidated Balance Sheets 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 to expect 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 Consolidated Balance Sheets at fair value, with subsequent changes in fair value recorded in net 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 net 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 net 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 the hedging 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.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate.

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 denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in self-sustaining 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.

G. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

H. Collateral Paid and Received

The terms and conditions of certain contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

I. Inventory

I. Fuel

The majority of fuel and purchased power recorded on the Consolidated 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 and lower production as maintenance is performed. 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 includes all applicable expenditures and charges incurred in bringing inventory to its existing condition and location.

II. Energy Trading

Commodity inventories held in the Energy Trading segment are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

J. 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 the 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.

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 conditions affecting the Corporation, the market, and the 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 consolidated 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 calculati ng the present value of expected future cash flows related to the asset.

K. Goodwill

Goodwill is the cost of an acquisition less the fair value of the related 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 segment to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting segments to which the goodwill relates is compared to the carrying values of the reporting segments. The Corporation determined that the fair value of each reporting segment exceeded its carrying values as at Dec. 31, 2010 and 2009.

L. 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 Canadian Hydro Developers, Inc. ("Canadian Hydro") *(Note 24)* and CE Generation LLC ("CE Gen"), a jointly controlled enterprise*(Note 33)*. 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.

M. Project Development Costs

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.

N. 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.

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 net 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.

O. 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 fut ure benefit payments. As the members of the Canadian Registered Plan are now almost all inactive, the past service costs from plan amendments and 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 are amortized over the Estimated Average Remaining Life. 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. This method has not been applied to the other plans as they did not qualify because the majority of their members are still active. These plans are amortized using Estimated Average Remaining Service Life.

P. Long-Term Debt

Transaction costs are recorded against the carrying value of long-term debt. The Corporation uses the effective interest 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.

Q. Asset Retirement Obligation ("ARO")

The Corporation recognizes AROs 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 accreted 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.

R. Stock-Based Compensation Plans

The Corporation has two types of stock-based compensation plans as described in Note 31. 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 comparator group. 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. Compensation expense is reduced by forfeiture s in the period they are incurred.

S. Accounting for Emission Credits and Allowances

Purchased emission allowances are recorded on the Consolidated Balance Sheets 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 Consolidated Balance Sheets 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.

T. 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. Any remaining net book value of the component being replaced is expensed through depreciation. 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.

U. Business Combinations

Acquisitions are recorded using the purchase method of accounting in accordance with Handbook Section 1581,*Business Combinations*, with the results of operations included in these consolidated financial statements from the date of acquisition *(Note 24)*. The purchase price has been allocated to assets acquired and liabilities assumed at the date of acquisition. The amounts assigned to the net assets acquired have given rise to future income tax liabilities that have been recorded as part of the purchase price allocation. The excess of the purchase price over the fair values assigned to the identifiable net assets acquired has been recorded as goodwill.

2. Accounting Changes

A. Comparative Figures

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

B. Current Year Accounting Changes

I. Inventory

During the second quarter of 2010, the Corporation modified its inventory measurement policy for commodity inventories held in its Energy Trading business segment to better reflect the nature of the underlying inventory and the segment's business objectives. Commodity inventories held in the

Energy Trading segment are now measured at fair value less costs to sell, as opposed to the lower of cost and net realizable value. Changes in fair value less costs to sell are recognized in net earnings in the period of change. The effect of this change on current and prior periods was not material. Accordingly, the change has been applied prospectively and prior periods have not been restated.

II. Change in Estimate - Useful Lives

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, TransAlta's economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to the same period in 2009.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

C. Prior Year Accounting Changes

I. Financial Instruments - Disclosures

On Oct. 1, 2009, the Corporation adopted amendments to Section 3862, *Financial Instruments - Disclosures, to converge with Improving Disclosures about Financial Instruments (Amendments to IFRS 7).* The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. The implementation of this standard did not have an impact upon the consolidated financial statements as the disclosure requirements are already provided as part of the Corporation's existing financial instrument disclosures.

II. Financial Instruments - Recognition and Measurement

On July 29, 2009, the Corporation retrospectively adopted, to Jan. 1, 2009, *Impairment of Financial Assets*, amending Section 3855, *Financial Instruments - Recognition and Measurement*. The amendments changed the categories into which debt instruments could be classified and the impairment requirements for certain financial assets. Consequential amendments to Section 3025, *Impaired Loans*, were made to incorporate these changes. The implementation of this standard did not have an impact upon the consolidated financial statements.

On July 1, 2009, the Corporation adopted *Embedded Derivatives on Reclassification of Financial Assets*, amending Section 3855, *Financial Instruments - Recognition and Measurement*. The amendment indicates that contracts with embedded derivatives cannot be reclassified out of the held for trading category if the embedded derivative cannot be fair valued. The implementation of this standard did not have an impact upon the consolidated financial statements.

III. Credit Risk

On Jan. 1, 2009, the Corporation adopted the Emerging Issues Committee ("EIC") Abstract 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC-173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Disclosure required as a result of adopting this standard can be found in Note 8.

IV. Deferral of Costs and Internally Developed Intangibles

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

V. Mining Exploration Costs

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

D. Future Accounting Changes

I. International Financial Reporting Standards ("IFRS") Convergence

On Jan. 1, 2011, the Corporation adopted IFRS for publicly accountable enterprises as required by the Accounting Standards Board of Canada.

While IFRS uses a conceptual framework similar to Canadian GAAP, there are several significant differences in accounting policies that have been addressed as part of the convergence project. In respect of PP&E, additional disclosures reconciling the changes in individual classes of PP&E and accumulated amortization are required, and costs related to major inspection activities are recognized as part of the carrying value of PP&E and depreciated over the period until the next major inspection. For employee future benefits, the Corporation recognizes all experience and transitional gains and losses to retained earnings with subsequent experience gains and losses being recorded in OCI. Long-term contracts deemed to be finance leases resulted in the associated PP&E being removed from the Consolidated Balance Sheets and the recognition of a long-term receivable, representing the present value of lease payments to be received over the life of the contract. A portion of the payments received under the contract are recognized as a reduction of the finance lease receivable and a portion is recognized as interest income, the amount which will vary dependent upon the interest rate and duration of the contract. Provisions for asset retirement obligations are revalued at the end of each quarterly and annual reporting period using current-market based interest rates instead of remaining at historic rates. The related accretion expense is classified as finance (interest) cost under IFRS. Asset impairment testing no longer utilizes undiscounted cash future cash flows to initially assess for impairment. Instead, when an indicator of impairment exists, an asset's carrying amount is compared to the greater of its value in use or fair value less costs to sell. IFRS also requires asset impairment charges to be reversed in subsequent periods if the initial indicator of impairment has reversed.< /p>

A steering committee, comprised of senior representatives across the Corporation, continues to monitor the progress of the transition to IFRS and will continue to meet regularly until the first interim report under IFRS is completed in 2011. Quarterly updates are provided to the Audit and Risk Committee.

3. Asset Impairment Charges

During the fourth quarter of 2010, the Corporation completed its annual comprehensive impairment assessment based on fair value estimates derived from the long-range forecast and market values evidenced in the marketplace. As a result, the Corporation recorded a pre-tax impairment charge of $89 million ($79 million after deducting the amount that is attributable to the non-controlling interest) on certain Generation assets, comprised of a $65 million charge against the natural gas fleet and a $24 million charge against the coal fleet. The natural gas fleet impairment reflects lower forecast pricing at one of the Corporation's merchant facilities and the pending sale of the Corporation's 50 per cent interest in the Meridian facility, which had no impact to consolidated earnings as the impairment was attributable to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and primarily reflects the Corporation's shift in 2010 to managing the coal-fired generation facilities on a unit pair basis, resulting in the impairment assessment now being performed on a unit pair basis.

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

4. Other Income

During 2010, the 54 megawatt ("MW") expansion of the Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project is approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills expansion project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010, and an additional $2 million of proceeds related to costs expected in 2011. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

During 2009, the Corporation sold a 17 per cent interest in its initial Kent Hills project to Natural Forces for proceeds of $29 million, and recorded a pre-tax gain of $1 million. The Corporation also settled an outstanding commercial issue related to the sale of its Mexican equity investment for a pre-tax gain of $7 million.

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.

5. Non-Controlling Interests

A. Consolidated Statements of Earnings

Year ended Dec. 31	2010	2009	2008
Stanley Power's interest in TransAlta Cogeneration, L.P. *(Note 33)*	**19**	23	32
25 per cent interest in Saranac Partnership not owned by CE Gen	**-**	14	29
Natural Forces' interest in Kent Hills *(Note 4)*	**1**	1	-
Total	**20**	38	61

B. Consolidated Balance Sheets

As at Dec. 31	2010	2009
Stanley Power's interest in TransAlta Cogeneration, L.P.	**393**	434
25 per cent interest in Saranac Partnership not owned by CE Gen	**15**	16
Natural Forces' interest in Kent Hills	**43**	28
Non-controlling interests portion of OCI	**(16)**	-
Total	**435**	478

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2009	478
Distributions paid	(62)
Non-controlling interests portion of net earnings, including asset impairment *(Note 3)*	20
Non-controlling interests portion of OCI	(16)
Acquisition of minority interest in Kent Hills *(Note 4)*	15
As at Dec. 31, 2010	**435**

C. Consolidated Statements of Cash Flows

Distributions paid by subsidiaries to non-controlling interests are as follows:

Year ended Dec. 31	2010	2009	2008
TransAlta Cogeneration, L.P.	**60**	38	59
Saranac	**-**	18	39
Kent Hills	**2**	2	-
Total	**62**	58	98

6. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2010	2009	2008
Earnings before income taxes	**220**	196	258
Equity loss	**-**	-	(97)

Earnings before income taxes and equity loss	**220**	196	355
Statutory Canadian federal and provincial income tax rate (%)	**28**	29	30
Expected income tax expense	**62**	57	105
(Decrease) increase in income taxes resulting from:			
Lower effective foreign tax rates	**(26)**	(29)	(24)
Resolution of uncertain tax matters	**(30)**	-	(15)
Tax recovery on sale of Mexican equity investment *(Note 24)*	**-**	-	(35)
Effect of tax rate changes	**-**	(6)	-
Statutory and other rate differences	**(10)**	(4)	(7)
Other	**5**	(3)	(1)
Income tax expense	**1**	15	23
Effective tax rate (%)	**1**	8	6

II. Components of Income Tax Expense

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

Year ended Dec. 31	**2010**	2009	2008
Current tax (recovery) expense	**(27)**	(6)	22
Future income tax expense related to the origination and reversal of temporary differences	**28**	27	1
Future income tax recovery resulting from changes in tax rates or laws	**-**	(6)	-
Income tax expense	**1**	15	23

During 2010, TransAlta recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters, which was received in 2010. Interest expense also decreased by $14 million as a result of tax-related interest recoveries.

B. Consolidated Balance Sheets

Significant components of the Corporation's future income tax assets (liabilities) are as follows:

As at Dec. 31	**2010**	2009
Net operating and capital loss carryforwards	**382**	297
Future site restoration costs	**86**	75
Property, plant, and equipment	**(886)**	(839)
Risk management assets and liabilities, net	**(113)**	(82)
Employee future benefits and compensation plans	**14**	19
Allowance for doubtful accounts	**18**	19
Other deductible temporary differences	**32**	38
Net future income tax liability	**(467)**	(473)

Presented in the Consolidated Balance Sheets as follows:

As at Dec. 31	**2010**	2009
Assets		
Long-term	**240**	234
Liabilities		
Current	**(77)**	(45)
Long-term	**(630)**	(662)
Net future income tax liability	**(467)**	(473)

7. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost *(Note 1(F))*. The following table highlights the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Dec. 31, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	**-**	**-**	**58**	**-**	**58**
Accounts receivable	**-**	**-**	**428**	**-**	**428**
Collateral paid	**-**	**-**	**27**	**-**	**27**
Risk management assets					
Current	**186**	**79**	**-**	**-**	**265**
Long-term	**204**	**4**	**-**	**-**	**208**
Financial liabilities					
Short-term debt	**-**	**-**	**-**	**1**	**1**
Accounts payable and accrued liabilities	**-**	**-**	**-**	**503**	**503**
Collateral received	**-**	**-**	**-**	**126**	**126**
Dividends payable				**130**	**130**
Risk management liabilities					
Current	**5**	**30**	**-**	**-**	**35**
Long-term	**123**	**-**	**-**	**-**	**123**
Long-term debt recourse[1]	**-**	**-**	**-**	**3,685**	**3,685**

Long-term debt non-recourse[1]	**-**	**-**	**-**	**549**	**549**

Carrying value of financial instruments as at Dec. 31, 2009

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	82	-	82
Accounts receivable	-	-	421	-	421
Collateral paid	-	-	27	-	27
Risk management assets					
Current	130	14	-	-	144
Long-term	219	5	-	-	224
Long-term receivable			49		49
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	521	521
Collateral received	-	-	-	86	86
Dividends payable	-	-	-	61	61
Risk management liabilities					
Current	28	17	-	-	45
Long-term	75	3	-	-	78
Long-term debt recourse[1]	-	-	-	3,864	3,864
Long-term debt non-recourse[1]	-	-	-	578	578

1 Includes current portion.

B. Fair Value of Financial Instruments

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

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

Level Determinations and Classifications

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

Level I

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

Level II

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

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. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

Level III

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

In limited circumstances, the Corporation 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 for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally developed fundamental price forecast is used in the valuation.

As a result of the acquisition of Canadian Hydro, TransAlta also has various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

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.

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments in relation to trading activities and certain contracting activities.

The following table summarizes the key factors impacting the fair value of the energy trading risk management assets and liabilities by classification level during the year ended Dec. 31, 2010:

	Hedges			Non-hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2009	-	297	(27)	-	-	1	-	297	(26)
Changes attributable to:									
Market price changes on existing contracts	-	146	11	-	(5)	2	-	141	13
Market price changes on new contracts	-	30	-	(1)	10	(2)	(1)	40	(2)
Contracts settled	-	(108)	(4)	-	2	(1)	-	(106)	(5)
Discontinued hedge accounting on certain contracts	-	(46)	-	-	46	-	-	-	-
Net risk management assets (liabilities) at Dec. 31, 2010	**-**	**319**	**(20)**	**(1)**	**53**	**-**	**(1)**	**372**	**(20)**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			7			(1)			6
Realized gain included in earnings before income taxes			4			1			5

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

The effect of using reasonable possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at Dec. 31, 2010 is estimated to be +/- $14 million (2009 - $24 million). Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

The total change in Level III financial assets and liabilities held at Dec. 31, 2010 that was recognized in pre-tax earnings for the year ended Dec. 31, 2010 was a $5 million gain (2009 - $1 million).

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

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	-
	Level II	182	138	22	(4)	(9)	(10)	319
	Level III	1	1	-	-	-	(22)	(20)
Non-hedges	Level I	(1)	(1)	1	-	-	-	(1)
	Level II	47	1	5	-	-	-	53
	Level III	1	-	-	(1)	-	-	-
Total by level	Level I	(1)	(1)	1	-	-	-	(1)
	Level II	229	139	27	(4)	(9)	(10)	372
	Level III	2	1	-	(1)	-	(22)	(20)
Total net assets (liabilities)		**230**	**139**	**28**	**(5)**	**(9)**	**(32)**	**351**

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt, and the net investment in self-sustaining foreign subsidiaries.

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the year ended Dec. 31, 2010:

	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 at Dec. 31, 2009	-	(24)	-	-	(2)	-	-	(26)	-
Changes attributable to:									
Market price changes on existing contracts	-	(9)	-	-	2	-	-	(7)	-
Market price changes on new contracts	-	(25)	-	-	-	-	-	(25)	-
Contracts settled	-	21	-	-	1	-	-	22	-
Net risk management (liabilities) assets at Dec. 31, 2010	**-**	**(37)**	**-**	**-**	**1**	**-**	**-**	**(36)**	**-**

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. For hedges that remain effective and qualify for hedge accounting, any

change in value will be deferred in AOCI until the instrument is settled, or until such time as the hedged item affects net earnings, or there is a reduction in the net investment in the foreign operations.

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

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	-
	Level II	(1)	(9)	(6)	(2)	(32)	13	(37)
	Level III	-	-	-	-	-	-	-
Non-hedges	Level I	-	-	-	-	-	-	-
	Level II	1	-	-	-	-	-	1
	Level III	-	-	-	-	-	-	-
Total by level	Level I	-	-	-	-	-	-	-
	Level II	-	(9)	(6)	(2)	(32)	13	(36)
	Level III	-	-	-	-	-	-	-
Total net (liabilities) assets		**-**	**(9)**	**(6)**	**(2)**	**(32)**	**13**	**(36)**

	Fair value[1]				Total
	Level I	Level II	Level III	Total	carrying value
Financial assets and liabilities measured at other than fair value					
Long-term debt - Dec. 31, 2010[2]	**-**	**4,460**	**-**	**4,460**	**4,234**
Long-term debt - Dec. 31, 2009[2]	-	4,499	-	4,499	4,442

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, accounts receivable, collateral paid, long-term receivable, short-term debt, accounts payable and accrued liabilities, collateral received, and dividends payable).

2 Includes current portion.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation 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.

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Balance Sheets in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the year is as follows:

As at Dec. 31	**2010**	2009	2008
Unamortized (loss) gain at beginning of year	**(1)**	2	3
New inception gains (losses)	**3**	(1)	1
Amortization recorded in net earnings during the year	**(1)**	(2)	(2)
Unamortized gain (loss) at end of year	**1**	(1)	2

8. Risk Management Activities

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at Dec. 31	**2010**					2009
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	**-**	**183**	**-**	**78**	**261**	144
Long-term	**-**	**185**	**-**	**4**	**189**	207
Total energy trading risk management assets	**-**	**368**	**-**	**82**	**450**	351
Other						
Current	**1**	**-**	**2**	**1**	**4**	-
Long-term	**-**	**-**	**19**	**-**	**19**	17
Total other risk management assets	**1**	**-**	**21**	**1**	**23**	17
Risk management liabilities						
Energy trading						
Current	**-**	**-**	**-**	**30**	**30**	30
Long-term	**-**	**69**	**-**	**-**	**69**	50
Total energy trading risk management liabilities	**-**	**69**	**-**	**30**	**99**	80
Other						
Current	**5**	**-**	**-**	**-**	**5**	15
Long-term	**-**	**54**	**-**	**-**	**54**	28
Total other risk management liabilities	**5**	**54**	**-**	**-**	**59**	43
Net energy trading risk management assets	**-**	**299**	**-**	**52**	**351**	271
Net other risk management (liabilities) assets	**(4)**	**(54)**	**21**	**1**	**(36)**	(26)
Net total risk management (liabilities) assets	**(4)**	**245**	**21**	**53**	**315**	245

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (2009 - U.S.$1,100 million), and borrowings under a U.S. dollar denominated credit facility with a face value of U.S.$300 million (2009 - U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in self-sustaining foreign operations.

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

Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap used as part of the net investment hedge is as follows:

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
-	**-**	**-**	AUD34	(2)	2010

Foreign Currency Contracts

Outstanding foreign currency forward sale (purchase) contracts used as part of the net investment hedge are as follows:

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
AUD180	**(1)**	**2011**	AUD120	(2)	2010
U.S.(41)	**(3)**	**2011**	U.S.(182)	(1)	2010

ii. Effect on the Consolidated Statements of Comprehensive Income

For the year ended Dec. 31, 2010, a net after-tax loss of $27 million (2009 - loss of $69 million, 2008 - gain of $47 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following tables summarize the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income:

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI for the year ended Dec. 31, 2010	Location of gain reclassified from OCI	Pre-tax gain reclassified from OCI
Long-term debt	**68**	Foreign exchange	**(5)**
Foreign exchange	**(29)**		
OCI impact	**39**	**OCI impact**	**(5)**

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI for the year ended Dec. 31, 2009	Pre-tax loss recognized in OCI for the year ended Dec. 31, 2008
Long-term debt	233	(257)
Cross currency	(3)	(62)
Foreign exchange	(64)	(37)
OCI impact	166	(356)

b. *Cash Flow Hedges*

i. Energy Trading Risk Management

The Corporation's outstanding energy trading derivative instruments designated as hedging instruments at Dec. 31, 2010, were as follows:

(Thousands)	**Dec. 31, 2010**		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**28,814**	**10**	28,989	-
Natural gas (GJ)	**1,925**	**32,751**	2,163	360
Oil (gallons)	**-**	**12,432**	-	25,074

During the fourth quarter of 2010, unrealized pre-tax gains of $13 million were recognized in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Receipts and Expenditures

The Corporation uses forward foreign exchange contracts to hedge a portion of its future foreign denominated receipts and expenditures as follows:

As at Dec. 31	**2010**			2009			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
217	**U.S.200**	**(12)**	**2011-2017**	91	U.S.78	(8)	2010
U.S.8	**8**	**-**	**2011**	U.S.14	15	-	2010
-	**-**	**-**	**-**	AUD4	U.S.3	-	2010

Foreign Exchange Forward Contracts on Foreign Denominated Debt

Outstanding foreign exchange forward purchase contracts used to manage foreign exchange exposure on debt not designated as a net investment hedge are as follows:

As at Dec. 31	**2010**		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.300	**(7)**	**2012**	-	-	-
U.S.300	**(7)**	**2013**	-	-	-

Cross-Currency Swap

TransAlta uses cross-currency swaps to manage foreign exchange risk exposures on foreign denominated debt as follows:

As at Dec. 31	**2010**		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.500	**(28)**	**2015**	U.S.500	(16)	2015

iii. Interest Rate Risk Management

The Corporation also had outstanding forward start interest rate swaps that converted floating rate debt into fixed rate debt with fixed rates ranging from 3.5 per cent to 4.6 per cent. These swaps were closed out upon the issuance of the U.S.$300 million senior notes during the first quarter of 2010 and the resulting losses have been included in AOCI and will be amortized to earnings over the original 10-year term of the swaps.

As at Dec. 31	**2010**		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
-	**-**	**-**	U.S.300	(8)	2020

iv. Effect on the Consolidated Statements of Comprehensive Income

Forward sale and purchase commodity contracts, foreign exchange contracts, cross-currency swaps, as well as interest rate 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.

The following tables summarize the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets:

Year ended Dec. 31, 2010

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of gain recognized in earnings	Pre-tax gain recognized in earnings
Commodity	**299**	Revenue	**(234)**	Revenue	**13**
Foreign exchange loss on project hedges	**(15)**	Property, plant and equipment	**11**	Interest expense	**-**
Foreign exchange loss on U.S. debt	**(14)**	Foreign exchange loss on U.S. debt	**39**		
Cross-currency swaps	**(10)**				
Interest rate	**(9)**	Interest expense	**1**		
OCI impact	**251**	**OCI impact**	**(183)**	**Earnings impact**	**13**

Year ended Dec. 31, 2009

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of loss recognized in earnings	Pre-tax loss recognized in earnings
Commodity	394	Revenue	(205)	Revenue	-
Foreign exchange loss on project hedges	(31)	Property, plant and equipment	(15)	Interest expense	(2)
Interest rate	37	Interest expense	1		
OCI impact	400	OCI impact	(219)	Earnings impact	(2)

Year ended Dec. 31, 2008

	Effective portion		
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of loss reclassified from OCI	Pre-tax loss reclassified from OCI
Commodity	352	Revenue	91
Foreign exchange gain on project hedges	31	Property, plant and equipment	8
Interest rate	(56)	Interest expense	-
OCI impact	327	OCI impact	99

Over the next 12 months, the Corporation estimates that $121 million of after-tax gains 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.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 5.75 per cent to 6.9 per cent, to floating rate debt through interest rate swaps as shown below *(Note 17)*:

As at Dec. 31	**2010**		2009		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset (liability)	Maturity
100	**2**	**2011**	100	7	2011
U.S.100	**3**	**2013**	U.S.50	(1)	2013
U.S.200	**16**	**2018**	U.S.100	7	2018

Including the interest rate swaps above, 25 per cent of the Corporation's debt is subject to floating interest rates (2009 - 31 per cent).

ii. Effect on the Consolidated Statements of Comprehensive Income

No ineffective portion of fair value hedges was recorded in 2010, 2009, or 2008.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings:

Year ended Dec. 31		**2010**	2009	2008
Derivatives in fair value hedging relationships	Location of gain (loss) on the Consolidated Statements of Earnings			
Interest rate contracts	Net interest expense	**8**	20	(26)
Long-term debt	Net interest expense	**(8)**	(20)	26
Net earnings impact		-	-	-

II. Non-Hedges

The Corporation enters into various derivative transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting where the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management

The Corporation enters into certain commodity hedging transactions that are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported as revenue in the period the change occurs. The Corporation's outstanding energy trading derivative instruments that are not designated as hedging instruments were as follows:

(Thousands)	**Dec. 31, 2010**		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**26,553**	**24,924**	14,107	14,844
Natural gas (GJ)	**633,483**	**640,731**	323,793	309,764
Transmission (MWh)	**-**	**7,535**	-	4,852
Oil (gallons)	**-**	**5,040**	-	-

b. Cross-Currency Interest Rate Swaps

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

As at Dec. 31	**2010**		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
-	**-**	**-**	AUD13	(2)	2010

c. Foreign Currency Contracts

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

Outstanding notional amounts and fair values associated with these forward contracts are as follows:

As at Dec. 31	**2010**			2009			
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
20	**AUD20**	**1**	**2011**	-	-	-	-
1	**U.S.1**	**-**	**2011-2012**	-	-	-	-
-	**-**	**-**	**-**	U.S.13	14	-	2010

d. Total Return Swaps

The Corporation also has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge

accounting has not been chosen. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

e. Effect on the Consolidated Statements of Comprehensive Income

The Corporation utilizes a variety of derivatives in its proprietary trading activities, including certain commodity hedging activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. During the fourth quarter of 2010, unrealized pre-tax gains of $30 million were recognized in earnings due to certain power hedging relationships being discontinued as they were deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges n ot been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change. For the year ended Dec. 31, 2010, the Corporation recognized a net unrealized gain of $33 million (2009 - $3 million net unrealized loss, 2008 - $14 million net unrealized loss).

The tables below summarize the net realized and unrealized gains and losses included in net earnings that are associated with other risk management derivatives not designated as hedges:

Year ended Dec. 31		**2010**	
	Net unrealized gains	Net realized losses	Total
Foreign exchange	**2**	**(1)**	**1**
Other	**-**	**(1)**	**(1)**

Year ended Dec. 31		2009	
	Net unrealized losses	Net realized losses	Total
Foreign exchange	-	(1)	(1)

Year ended Dec. 31		2008	
	Net unrealized losses	Net realized gains	Total
Foreign exchange	(3)	14	11
Other	-	1	1

B. 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 Energy Trading 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 earnings in the period that the price changes occur. VaR at Dec. 31,

2010 associated with the Corporation's proprietary energy trading activities was $5 million (2009 - $3 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 net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta based on the average monthly Alberta Power Pool prices. While the contracts do not create any obligation for the physical delivery of electricity to other parties, the Corporation believes it has sufficient electrical generation available to satisfy these contracts.

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, 2010 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $52 million (2009 - $45 million).

The Corporation's policy on asset-backed transactions is to seek NPNS contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2010 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was $6 million (2009 - 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 payments 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 net earnings and OCI, for the years ended Dec. 31, 2010, 2009, and 2008, due to changes in market interest rates affecting the Corporation's floating rate debt and held for trading and hedging interest rate 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 a reasonable potential change in market interest rates over the next quarter.

Year ended Dec. 31	**2010**		2009		2008	
	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
50 basis point change	**4**	**-**	5	(10)	2	-

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

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro and the U.S. and Australian dollars, as a result of investments and operations in foreign jurisdictions, the net 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 net earnings and OCI, for the years ended Dec, 31, 2010, 2009, and 2008, due to changes in foreign 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 six cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2010**		2009		2008	
	Net earnings (decrease) increase[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
U.S.	**(4)**	**9**	(5)	3	(5)	3
AUD	**1**	**-**	(1)	-	(3)	-
Euro	**-**	**-**	-	-	-	3
Total	**(3)**	**9**	(6)	3	(8)	6

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

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

II. Credit Risk

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, cash collateral, 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 t he 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, 2010, TransAlta had one counterparty whose net settlement position 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, 2010, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading, net of any collateral held, at Dec 31, 2010 was $43 million (2009 - $63 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at Dec. 31, 2010:

(Per cent)	Investment grade	Non-investment grade	Total
Accounts receivable	**96**	**4**	**100**
Risk management assets	**100**	**-**	**100**

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in Note 9.

At Dec. 31, 2010, the Corporation did not have any significant past due trade receivables except as disclosed in Note 28.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used in proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong balance sheet and stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

TransAlta manages 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 Exposure Management Committee, senior management, and Board of Directors; and maintaining investment grade credit ratings.

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

	2011	2012	2013	2014	2015	2016 and thereafter	Total
Accounts payable and accrued liabilities	503	-	-	-	-	-	503
Collateral received	126	-	-	-	-	-	126
Debt[1]	254	674	629	231	681	1,769	4,238
Energy trading risk management (assets) liabilities[2]	(230)	(139)	(28)	5	9	32	(351)
Other risk management liabilities (assets)[2]	-	9	6	2	32	(13)	36
Interest on long-term debt	237	214	194	157	127	960	1,889
Dividends payable	130	-	-	-	-	-	130
Total	**1,020**	**758**	**801**	**395**	**849**	**2,748**	**6,571**

1 Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.

2 Net risk management assets and liabilities as above.

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2010, $40 million (2009 - $45 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Gen has been pledged as collateral for certain CE Gen debt. Should any defaults occur, the debtholders would have first claim on these assets.

At Dec. 31, 2010, the Corporation provided $27 million (2009 - $27 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At Dec. 31, 2010, the Corporation received $126 million (2009 - $86 million) in cash collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

III. Contingent Features in Derivative Instruments

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

As at Dec. 31, 2010, the Corporation had posted collateral of $17 million (2009 - $37 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $40 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2010.

9. Accounts Receivable

As at Dec. 31	2010	2009
Gross accounts receivable	**474**	470
Allowance for doubtful accounts *(Note 28)*	**(46)**	(49)
Net accounts receivable	**428**	421

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2009	49
Change in foreign exchange rates	(3)
Balance, Dec. 31, 2010	**46**

10. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, are valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which also includes natural gas, is valued at fair value less costs to sell *(Note 2)*. The classifications are as follows:

As at Dec. 31	2010	2009
Coal	**47**	86
Natural gas	**5**	4
Purchased emission credits	**1**	-
Total	**53**	90

The decrease in coal inventory in 2010 compared to 2009 is primarily due to higher production at the coal facilities.

The change in inventory is outlined below:

Balance, Dec. 31, 2009	90
Net consumed	(36)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2010	**53**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2010 and 2009, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

11. Long-Term Receivable

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million.

12. Property, Plant, and Equipment

As at Dec. 31		2010			2009		
	Depreciable lives	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation equipment	**2-50**	**4,396**	**2,103**	**2,293**	4,693	2,266	2,427
Mining property & equipment	**3-50**	**917**	**368**	**549**	795	415	380
Gas generation	**2-30**	**2,047**	**955**	**1,092**	2,135	883	1,252
Geothermal generation	**10-20**	**334**	**127**	**207**	333	101	232
Hydro generation	**3-60**	**614**	**255**	**359**	609	238	371
Wind generation	**5-30**	**1,820**	**114**	**1,706**	1,554	59	1,495
Biomass	**10-25**	**2**	**-**	**2**	25	1	24
Capital spares and other	**3-41**	**310**	**87**	**223**	270	65	205
Assets under construction	**-**	**995**	**-**	**995**	1,038	-	1,038
Coal rights[1]	**-**	**148**	**92**	**56**	133	86	47
Land	**-**	**71**	**-**	**71**	68	-	68
Transmission systems	**15-50**	**52**	**28**	**24**	48	28	20
Total		**11,706**	**4,129**	**7,577**	11,701	4,142	7,559

1 Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserve.

The Corporation capitalized $48 million of interest to PP&E in 2010 (2009 - $36 million, 2008 - $21 million).

The change in PP&E is outlined below:

	Cost	Accumulated depreciation and amortization	Net book value
Balance, Dec. 31, 2009	11,701	4,142	7,559
Additions	790	-	790
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	(104)	-	(104)
Assets held for sale *(Note 13)*	(89)	(29)	(60)
Asset impairment charges *(Note 3)*	(80)	-	(80)
Change in foreign exchange rates	(70)	(26)	(44)
Depreciation	-	465	(465)
Disposals	(3)	(1)	(2)
Resolution of certain tax matters *(Note 9)*	(11)	-	(11)
Retirement of assets	(60)	(60)	-
Transfers	13	-	13
Wabamun decommissioning	(381)	(362)	(19)
Balance, Dec. 31, 2010	**11,706**	**4,129**	**7,577**

13. Assets and Liabilities Held for Sale

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, all associated assets and liabilities have been classified as held for sale under the Generation segment. The sale is effective Jan. 1, 2011 and is expected to close in early 2011. The impact of this transaction on net earnings is not expected to be significant.

14. Goodwill

The change in goodwill is outlined below:

Balance, Dec. 31, 2009	434
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	87
Change in foreign exchange rates	(4)
Balance, Dec. 31, 2010	**517**

A portion of goodwill in Generation relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars *(Note 29)*.

15. Intangible Assets

The change in intangible assets is outlined below:

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2009	618	274	344
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	(10)	-	(10)
Additions	3	-	3
Change in foreign exchange rates	(21)	(13)	(8)
Amortization	-	25	(25)
Balance, Dec. 31, 2010	**590**	**286**	**304**

A portion of intangible assets relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars.

16. Other Assets

As at Dec. 31	**2010**	2009
Deferred license fees	**23**	22
Accrued benefit asset *(Note 32)*	**25**	18
Project development costs	**49**	45
Deferred service costs	**12**	19
Keephills 3 transmission deposit	**8**	8
Other	**10**	9
Total other assets	**127**	121

Deferred license fees consist primarily of licenses to lease the land on which certain generating assets are located, and are being amortized on a straight-line basis over the useful life of the generating assets to which the licenses relate.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts for projects no longer probable of occurring are charged to expense.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee site. These costs are being amortized over the life of these projects.

The Keephills 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit for Keephills 3. The full amount of the deposit is anticipated to be reimbursed over the next 10 years, as long as certain performance criteria are met.

17. Long-Term Debt and Net Interest Expense

A. Amounts Outstanding

As at Dec. 31	2010			2009		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest [1]
Credit facilities[2]	**645**	**645**	**1.4%**	1,063	1,063	1.0%
Debentures	**1,057**	**1,076**	**6.7%**	1,055	1,076	6.7%
Senior notes[3]	**1,931**	**1,902**	**6.0%**	1,687	1,684	5.9%
Non-recourse	**549**	**562**	**6.5%**	578	589	6.3%
Other	**52**	**52**	**6.7%**	59	59	6.7%
	4,234	**4,237**		4,442	4,471	
Less: current portion	**(255)**	**(253)**		(31)	(31)	
Total long-term debt	**3,979**	**3,984**		4,411	4,440	

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

2 Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.

3 2010 - U.S.$1,900 million, 2009 - U.S.$1,600 million.

A portion of the fixed rate components of the Corporation's debentures and senior notes have been hedged using fixed to floating interest rate swaps *(Note 8)* and therefore the Corporation has included the fair value of these swaps with the value of the debt which is also recorded at fair value. The balance of long-term debt is not hedged and therefore recorded at amortized cost.

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's businesses. The facility is a five-year revolving credit facility which was last renewed in May 2007 and matures in 2012. The U.S.$300 million committed facility is a five-year facility that matures in 2013. Interest rates on the credit facilities vary depending on the option selected: Canadian prime, bankers' acceptance, U.S. LIBOR or U.S. base rate, in accordance with a pricing grid that is standard for such facilities. A total of U.S.$300 million of the credit facilities has been designated as a hedge of the Corporation's net investment of U.S. self-sustaining foreign operations. The Corporation also has $240 million available in committed bilateral credit facilities, all of which mature in 2012.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent and have maturity dates ranging from 2011 to 2030.

Senior Notes bear interest at rates ranging from 4.75 per cent to 6.75 per cent and have maturity dates ranging from 2012 to 2040. During 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040. A total of U.S.$800 million of the senior notes has been designated as a hedge of the Corporation's net investment of U.S. self-sustaining foreign operations.

Non-Recourse Debt consists of project financing debt, debt securities and senior secured bonds of CE Gen, debt related to the Wailuku River Hydroelectric L.P. ("Wailuku") acquisition, and debentures issued by Canadian Hydro. The CE Gen related assets have been pledged as security for the project financing debt. The CE Gen debt has maturity dates ranging from 2011 to 2018 and bears interest at rates ranging from 7.5 per cent to 8.3 per cent and includes debt with a cost of U.S.$171 million (2009 - U.S.$192 million). The Wailuku debt has a maturity date of 2021 and bears interest at a floating rate currently of 0.3 per cent and includes debt with a cost of U.S.$7 million (2009 - U.S.$8 million). The Canadian Hydro debt has maturity dates ranging from 2012 to 2018 and bears interest at rates ranging from 5.3 per cent to 10.9 per cent and includes debt with a cost of $363 million and U.S.$20 million (2009 - $365 million and U.S.$20 million).

Other consists of notes payable for the Windsor plant that bear interest at fixed rates and are recourse to the Corporation through a standby letter of credit. These mature in November 2014. Also included is a commercial loan obligation that 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.

TransAlta's debt contains terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2010, the Corporation was in compliance with all debt covenants.

B. Principal Repayments

2011	253
2012	674
2013	629
2014	231
2015	681
2016 and thereafter	1,769
Total [1]	**4,237**

1 Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.

C. Interest Expense

Year ended Dec. 31	2010	2009	2008
Interest on long-term debt	**243**	183	177
Interest income	**(17)**	(6)	(46)
Capitalized interest	**(48)**	(36)	(21)
Other	**-**	3	-
Net interest expense	**178**	144	110

The Corporation capitalizes interest during the construction phase of growth capital projects. The capitalized interest in 2010 relates primarily to Keephills 3, Ardenville, and Kent Hills. In 2009, the capitalized interest related primarily to Keephills 3 and associated mine capital, Blue Trail, and Summerview 2.

In 2008, 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, a $30 million interest refund from taxation authorities was recorded as interest income.

D. Guarantees

Letters of Credit

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Balance Sheets. 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, 2010 totalled $297 million (2009 - $334 million) with no (2009 - nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.0 billion (2009 - $2.1 billion) of committed credit facilities, of which $1.1 billion (2009 - $0.7 billion) is not drawn, and is available as of Dec. 31, 2010, subject to customary borrowing conditions.

In addition to the $1.1 billion available under the credit facilities, TransAlta also has $58 million of cash available.

18. Asset Retirement Obligation

The change in asset retirement obligation balances is summarized below:

Balance, Dec. 31, 2009	282
Liabilities incurred in period	3
Liabilities settled in period	(37)
Accretion expense	21
Transfer to liabilities held for sale *(Note 13)*	(3)
Revisions in estimated cash flows	(20)
Change in foreign exchange rates	(4)
	242
Less: current portion	(38)
Balance, Dec. 31, 2010	**204**

The Corporation has a right to recover a portion of future asset retirement costs.

Revisions in estimated cash flows are primarily due to changes in the estimated costs associated with the decommissioning of the Wabamun plant, which was shut down on March 31, 2010.

TransAlta estimates that the undiscounted amount of cash flow required to settle the asset retirement obligation is approximately $0.8 billion, which will be incurred between 2011 and 2072. The majority of the costs will be incurred between 2020 and 2050. An average discount rate of eight per cent and an inflation rate of two per cent were used to calculate the carrying value of the asset retirement obligation. At Dec. 31, 2010, the Corporation had provided a surety bond in the amount of U.S.$192 million (2009 - U.S.$192 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2010, the Corporation had provided letters of credit in the amount of $72 million (2009 - $67 million) in support of future retirement obligations at the Alberta mines.

19. Deferred Credits and Other Long-Term Liabilities

As at Dec. 31	**2010**	2009
Deferred coal revenues *(Note 25)*	**61**	51
Long-term power contracts	**28**	32
Accrued benefit liability *(Note 32)*	**51**	49
Commitments for transportation of natural gas	**9**	-
Long-term incentive accruals	**8**	4
Other	**12**	11
Total deferred credits and other long-term liabilities	**169**	147

The long-term power contracts represent the fair value adjustments for various plants to deliver power at less than the prevailing market price at the time of the acquisition. The long-term power contracts are amortized on a straight-line basis over the life of the contract.

20. Common Shares

A. Issued and Outstanding

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

Year ended Dec. 31	**2010**		2009	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**218.4**	**2,169**	197.6	1,761
Issued under dividend reinvestment and share purchase plan	**1.6**	**37**	-	-
Issued under stock option plans	**0.1**	**1**	-	-
Issued under Performance Share Ownership Plan	**0.2**	**4**	0.2	6
Issued[1]	**-**	**-**	20.6	402
Issued and outstanding, end of year	**220.3**	**2,211**	218.4	2,169

1 Net of issuance costs of $12 million after tax.

On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, 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, 2011 and expire after 10 years *(Note 31)*.

At Dec. 31, 2010 the Corporation had 2.2 million outstanding employee stock options (2009 - 1.5 million). For the year ended Dec. 31, 2010, 0.1 million options with a weighted average exercise price of $16.20 were exercised resulting in 0.1 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $26.61 *(Note 31)*.

During 2010, no shares were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program prior to its expiry on May 6, 2010. For the year ended Dec. 31, 2009, no shares were acquired or cancelled under the NCIB program. For the year ended Dec. 31, 2008, TransAlta purchased 3,886,400 shares at an average price of $33.46 per share for a total of $130 million.

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 is put before the shareholders every three years for approval, and was last approved on April 29, 2010.

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 shareholder. Each right will entitle a shareholder other than the acquiring 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, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. During the year ended Dec. 31, 2010, the Corporation issued 1.6 million common shares for $37 million. Under the terms of the DRASP plan, the Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

D. Earnings Per Share

Year ended Dec. 31	**2010**	2009	2008
Net earnings applicable to common shares	**218**	181	235
Basic and diluted weighted average number of common shares outstanding	**219**	201	199
Earnings per common share			
Basic and diluted	**1.00**	0.90	1.18

The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding*(Note 31)*.

E. Dividends

The following tables summarize the common share dividends in 2010 and 2009:

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends	Dividends paid in cash[1]	Dividends paid in shares under DRASP[1]
Jan. 29, 2010	April 1, 2010	0.29	-	63	60	3
April 1, 2010	July 1, 2010	0.29	-	64	49	15
July 22, 2010	Oct. 1, 2010	0.29	-	63	44	19
Oct. 28, 2010	Jan. 1, 2011	0.29	64	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	65		
Total		**1.45**	**129**	**319**		

1 Allocation of dividends paid in cash or shares will be determined at the payment date.

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2009	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Jan. 29, 2009	April 1, 2009	0.29	-	57	57	-
April 30, 2009	July 1, 2009	0.29	-	57	57	-
July 23, 2009	Oct. 1, 2009	0.29	-	58	58	-
Oct. 29, 2009	Jan. 1, 2010	0.29	63	63	63	-
Total		**1.16**	**63**	**235**		

21. Preferred Shares

A. Issued and Outstanding

The Corporation is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

Year ended Dec. 31		**2010**		
	Number of shares		Dividend rate per	Redemption price per

	(millions)	Amount	share	share
Issued and outstanding, beginning of year	-	-	-	-
Issued[1]	**12.0**	**293**	**1.15**	**25**
Issued and outstanding, end of year	**12.0**	**293**		

1 Net of issuance costs of $7 million after tax.

On Dec. 10, 2010, TransAlta completed a public offering of 12 million Series A Cumulative Rate Reset First Preferred Shares under a prospectus supplement to the short form base shelf prospectus dated Oct. 19, 2009 for gross proceeds of $300 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.15 per share as approved by the Board of Directors, payable quarterly, yielding 4.60 per cent per annum, for the initial period ending March 31, 2016. The dividend rate will reset on March 31, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 2.03 per cent. The preferred shares are redeemable at the option of TransAlta on or after March 31, 2016 and on March 31 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends. The first dividend was declared on Dec. 13, 2010.

The preferred shareholders will have the right to convert their shares into Series B Cumulative Rate Reset First Preferred Shares on March 31, 2016 and on March 31 of every fifth year thereafter. The holders of Series B preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 2.03 per cent.

B. Dividends

The following table summarizes the preferred share dividends declared in 2010:

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends
Dec. 13, 2010	March 31, 2011	**0.3497**	**1**	**1**

22. Shareholders' Equity

A reconciliation of shareholders' equity is as follows:

	Common shares	Preferred shares	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
Balance, Dec. 31, 2009	2,169	-	634	126	2,929
Net earnings	-	-	219	-	219
Shares issued	42	293	-	-	335
Dividends declared on common shares	-	-	(319)	-	(319)
Dividends declared on preferred shares	-	-	(1)	-	(1)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	-	-	-	(27)	(27)
Gains on derivatives designated as cash flow hedges, net of tax	-	-	-	164	164
Derivatives designated as cash flow hedges in prior periods transferred to the Consolidated Balance Sheets and net earnings in the current period, net of tax	-	-	-	(121)	(121)
Gains on translation of self-sustaining foreign operations transferred to net earnings, net of tax	-	-	-	(2)	(2)
Balance, Dec. 31, 2010	**2,211**	**293**	**533**	**140**	**3,177**

The components of AOCI are presented below:

As at Dec. 31	**2010**	2009
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and of tax	**(92)**	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	**232**	189
Total accumulated other comprehensive income	**140**	126

23. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	**2010**	2009	Increase/ (decrease)
Short-term debt and current portion of long-term debt	**256**	31	225
Less: cash and cash equivalents	**(58)**	(82)	24
	198	(51)	249
Long-term debt			
Recourse	**3,450**	3,857	(407)
Non-recourse	**529**	554	(25)
Non-controlling interests	**435**	478	(43)
Shareholders' equity			

Common shares	**2,211**	2,169	42
Preferred shares	**293**	-	293
Retained earnings	**533**	634	(101)
AOCI	**140**	126	14
	7,591	7,818	(227)
Total capital	**7,789**	7,767	22

Total capital remains largely unchanged from the prior year. The decrease in long-term debt is primarily due to the issuance of preferred shares and favourable foreign exchange movements.

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2009.

TransAlta's objectives in managing its capital structure are as follows:

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

Cash flow to interest coverage Cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest income. TransAlta targets to maintain this ratio in a range of four to five times.

Cash flow to debt Cash flow from operating activities before changes in working capital divided by average total debt. TransAlta targets to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital Debt less cash and cash equivalents divided by debt, non-controlling interests, and shareholders' equity less cash and cash equivalents. TransAlta targets to maintain this ratio in a range of 55 to 60 per cent.

These ratios are presented below:

Year ended Dec. 31	**2010**	2009
Cash flow to interest coverage (times)[1]	**4.3**	4.9
Cash flow to debt (%)[1]	**18.3**	20.5
Debt to invested capital (%)	**53.6**	56.1

1 Last 12 months.

The decrease in cash flow to interest coverage resulted from higher interest expense. The decrease in cash flow to debt resulted from an increase in debt balances *(Note 17)*. The decrease in debt to invested capital is due to U.S. dollar denominated debt being valued lower in Canadian dollar terms at Dec. 31, 2010 *(Note 17)*. TransAlta routinely monitors forecasts for net 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

For the years ended Dec. 31, 2010 and 2009, net cash outflows, after cash dividends and capital asset additions, are summarized below:

Year ended Dec. 31	**2010**	2009	Increase in cash flows
Cash flow from operating activities	**811**	580	231
Dividends paid on common shares	**(216)**	(226)	10
Capital asset expenditures	**(790)**	(904)	114
Net cash outflow	**(195)**	(550)	355

The increase in the total net cash flows primarily resulted from higher cash flows from operating activities and lower capital asset expenditures. TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2010, $1.1 billion of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta opportunistically accesses the capital market to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

During 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040.

During 2010, the Corporation issued 1.9 million common shares for total net proceeds of $42 million. The Corporation also issued 12.0 million preferred shares for total net proceeds of $293 million.

TransAlta's formal dividend policy targets to pay common shareholders an annual dividend in the range of 60 to 70 per cent of comparable net earnings, a non-GAAP measure, which in general excludes items that would not be considered to be part of normal operations.

24. Acquisitions and Disposals

A. Acquisitions

On Oct. 23, 2009, TransAlta acquired 87 per cent of Canadian Hydro through the purchase of the issued and outstanding shares of Canadian Hydro. On Nov. 4, 2009, TransAlta acquired the remaining 13 per cent of the issued and outstanding shares. The total cash consideration was $785 million. The results of Canadian Hydro are included in the consolidated financial statements of the Corporation from the acquisition date of Oct. 23, 2009.

The details of the cash consideration are as follows:

Total shares acquired (millions)	143.8
Price per share	5.25
Total consideration paid	755
Transaction costs	30
Total cash consideration	**785**

Final Allocation of Purchase Price

During the fourth quarter of 2010, the preliminary purchase price allocation was revised to reflect the results of management's assessment of value. The significant adjustments between the preliminary and final purchase price allocation were primarily due to the finalization of the fair values of property, plant, and equipment and intangible assets. As a result, a pre-tax decrease of $4 million has been reflected in depreciation expense. The resulting adjustments and final purchase price allocation are highlighted below:

	Acquisition fair values	Adjustments	Revised balances
Assets:			
Cash	19	-	19
Accounts receivable	25	-	25
Prepaid expenses	5	-	5
Property, plant, and equipment, net	1,291	(104)	1,187
Intangible assets	176	(10)	166
Other assets	22	-	22
Total assets acquired	1,538	(114)	1,424
Liabilities:			
Accounts payable and accrued liabilities	54	2	56
Current risk management liabilities	6	-	6
Long-term debt	931	-	931
Asset retirement obligation	3	-	3
Future income tax liabilities	29	(29)	-
Long-term risk management liabilities	34	-	34
Total liabilities assumed	1,057	(27)	1,030
Net assets purchased	481	(87)	394
Goodwill	304	87	391
Total purchase price	**785**	**-**	**785**

B. Disposals

Mexican Equity Investment

On Oct. 8, 2008, TransAlta successfully completed the sale of the Mexican equity investment to InterGen Global Ventures B.V. for a sale price of $334 million. 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 equity investment	147	
Deferred gains on financial instruments designated as hedges of the net assets of the Mexican equity investment	(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 $2 million.

25. Related Party Transactions

On Jan. 1, 2009, TAU and TransAlta Energy Corporation 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, predecessors of TAGP, a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Dec. 31, 2010, TAGP had received $61 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amo rtized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities *(Note 19)*.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TA Cogen, which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). 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 two of its plants over the period of the swap. The notional gas volumes in the swap transactions are equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

26. 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 unrecorded claim will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware, when taken as a whole, will have a material adverse effect on the Corporation.

27. Commitments

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, transmission, operating leases, mining agreements, long-term service agreements, interest on long-term debt, and growth project commitments are as follows:

	Fixed price gas purchase contracts	Transmission	Operating leases	Coal supply and mining agreements	Long-term service agreement	Interest on long-term debt[1]	Growth project commitments	Total
2011	8	1	14	55	19	237	106	440
2012	8	6	13	55	18	214	36	350
2013	9	7	12	55	17	194	-	294
2014	8	7	11	55	17	157	-	255
2015	8	7	10	60	9	127	-	221
2016 and thereafter	22	12	52	320	3	960	-	1,369
Total	**63**	**40**	**112**	**600**	**83**	**1,889**	**142**	**2,929**

1 Includes impact of derivatives.

A. Fixed Price Gas Purchase Contracts

Centralia Gas and the Corporation's Australia operations have contracts in place for the fixed portion of the gas costs at the plants.

B. Transmission

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.

C. Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment.

D. Coal Supply and Mining Agreements

At Centralia Thermal, a significant portion of production is subject to short- to medium-term energy sales contracts. Centralia Thermal also 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 extending to Dec. 31, 2013.

At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal.

E. Long-Term Service Agreements

TransAlta has various service agreements in place primarily for repairs and maintenance that may be required on turbines at various wind generating facilities.

F. Growth Project Commitments

On Sept. 13, 2010, TransAlta obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of its Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012. As at Dec. 31, 2010, the total capital incurred on this project was $3 million.

As part of the acquisition of Canadian Hydro on Oct. 23, 2009, TransAlta assumed the plans to design, build, and operate Bone Creek, a 19 MW hydro facility in British Columbia. The capital cost of the project is estimated at $48 million, net of expected cost recoveries of $6 million, and is expected to begin commercial operations in the first quarter of 2011. As at Dec. 31, 2010, the total capital incurred on this project was $54 million. The total estimated spend for Bone Creek is less than the amount incurred to date due to the timing of project spend and associated recoveries in 2011.

On Jan. 29, 2009, TransAlta announced two efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded by 23 MW each, to a total of 450 MW, and are expected to be operational by the end of 2012. The capital cost of the projects is estimated at $68 million. As at Dec. 31, 2010, the total capital incurred on these projects was $10 million.

Keephills 3 plant construction and associated mine capital costs are anticipated to be approximately $1.9 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $988 million. As at Dec. 31, 2010, total spend on this project was $928 million.

Growth project commitments are as follows:

	Sundance Unit 3	Keephills Unit 1 uprate	Keephills Unit 2 uprate	Keephills Unit 3	Total
2011	7	14	25	60	106
2012	17	16	3	-	36
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	-	-	-	-
2016 and thereafter	-	-	-	-	-
Total	**24**	**30**	**28**	**60**	**142**

G. Other

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. The remaining electrical capacity from these facilities is sold in 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 market prices 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 two five-year options for extensions to the contracts. The contracts cover up to 202 MWs, or 40 per cent, of the plant's maximum capacity. These contracts set payments for peak MWs, total MWhs supplied to the customers, and steam consumed, while TransAlta assumes the availability and heat rate risk. The remaining capacity at Sarnia is available for export to the merchant market, based on market prices. On Sept. 30, 2009, TransAlta entered a new agreement with the Ontario Power Authority to supply up to 444 MWs of electricity to the Ontario electricity market, which expires on Dec. 31, 2025. Electrical production at the remaining Ontario plants is subject to contracts expiring in two to seven 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 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 is in effect from Nov. 1, 2007 until Dec. 31, 2012.

28. Prior Period Regulatory Decision

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$46 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator and the California Department of Water Resources during the 2000-2001 period. In addition, the California parties have sought additional refunds which to date have been rejected by FERC. TransAlta does not believe the California parties will be successful in obtaining additional refunds and is pursuing cost offsets to the refunds awarded by FERC. TransAlta established a U.S.$46 million provision to cover any potential refunds and continues to seek relief from this obligation. A final ruling is not expected in the near fut ure.

29. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three 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 Energy Trading's intersegment charge for energy marketing in the amount of $5 million (2009 - $32 million, 2008 - $30 million). The intersegment cost allocation (recovery) decreased for the year ended Dec. 31, 2010 as a result of costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010. The change has been applied prospectively and prior periods have not been restated. Energy Trading'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, 2010	Generation	Energy Trading	Corporate	Total
Revenues	**2,778**	**41**	**-**	**2,819**
Fuel and purchased power	**1,202**	**-**	**-**	**1,202**
	1,576	**41**	**-**	**1,617**
Operations, maintenance, and administration	**549**	**17**	**68**	**634**
Depreciation and amortization	**438**	**2**	**19**	**459**
Taxes, other than income taxes	**27**	**-**	**-**	**27**
Intersegment cost allocation	**5**	**(5)**	**-**	**-**
	1,019	**14**	**87**	**1,120**
	557	**27**	**(87)**	**497**
Foreign exchange gain *(Note 8)*				**10**
Asset impairment charges *(Note 3)*				**(89)**
Net interest expense *(Notes 8 and 17)*				**(178)**
Earnings before non-controlling interests and income taxes				**240**

Year ended Dec. 31, 2009	Generation	Energy Trading	Corporate	Total
Revenues	2,723	47	-	2,770
Fuel and purchased power	1,228	-	-	1,228
	1,495	47	-	1,542
Operations, maintenance, and administration	550	31	86	667
Depreciation and amortization	453	4	18	475
Taxes, other than income taxes	22	-	-	22
Intersegment cost allocation	32	(32)	-	-
	1,057	3	104	1,164
	438	44	(104)	378
Foreign exchange gain *(Note 8)*				8
Asset impairment charges *(Note 3)*				(16)
Net interest expense *(Notes 8 and 17)*				(144)
Other income *(Note 4)*				8
Earnings before non-controlling interests and income taxes				234

Year ended Dec. 31, 2008	Generation	Energy Trading	Corporate	Total
Revenues	3,005	105	-	3,110
Fuel and purchased power	1,493	-	-	1,493
	1,512	105	-	1,617
Operations, maintenance, and administration	487	53	97	637
Depreciation and amortization	409	3	16	428
Taxes, other than income taxes	19	-	-	19
Intersegment cost allocation	30	(30)	-	-
	945	26	113	1,084
	567	79	(113)	533
Foreign exchange loss *(Note 8)*				(12)
Net interest expense *(Notes 8 and 17)*				(110)
Equity loss *(Note 24)*				(97)
Other income *(Note 4)*				5
Earnings before non-controlling interests and income taxes				319

Included above in Generation is $19 million (2009 - $9 million, 2008 - $5 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects and $3 million of government grants received as a reduction of PP&E.

II. Selected Consolidated Balance Sheets Information

As at Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Goodwill *(Note 14)*	**487**	**30**	**-**	**517**
Total segment assets	**9,323**	**132**	**438**	**9,893**

As at Dec. 31, 2009				
Goodwill *(Note 14)*	404	30	-	434
Total segment assets	9,144	148	494	9,786

A portion of goodwill relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars.

III. Selected Consolidated Statements of Cash Flows Information

Energy

Year ended Dec. 31, 2010	Generation	Trading	Corporate	Total
Capital expenditures	**759**	**-**	**31**	**790**
Year ended Dec. 31, 2009				
Capital expenditures	879	5	20	904
Year ended Dec. 31, 2008				
Capital expenditures	992	7	7	1,006

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

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

Year ended Dec. 31	2010	2009	2008
Depreciation and amortization expense on the Consolidated Statements of Earnings	**459**	475	428
Depreciation included in fuel and purchased power	**42**	40	38
Accretion expense included in depreciation and amortization expense	**(21)**	(24)	(22)
Other	**10**	2	7
Depreciation and amortization on the Consolidated Statements of Cash Flows	**490**	493	451

C. Geographic Information

I. Revenues

Year ended Dec. 31	2010	2009	2008
Canada	**1,764**	1,631	1,839
U.S.	**951**	1,042	1,165
Australia	**104**	97	106
Total revenue	**2,819**	2,770	3,110

II. Property, Plant, and Equipment and Goodwill

	Property, plant, and equipment *(Note 12)*		Goodwill *(Note 14)*	
As at Dec. 31	**2010**	2009	**2010**	**2009**
Canada	**6,370**	6,201	**447**	360
U.S.	**1,037**	1,182	**70**	74
Australia	**170**	176	**-**	-
Total	**7,577**	7,559	**517**	434

A change in foreign exchange rates from 2009 to 2010 has resulted in a $44 million decrease in net book value of PP&E and a $4 million decrease in goodwill. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect net earnings; rather, any cumulative translation gains and losses are reflected in AOCI.

30. Changes in Non-Cash Operating Working Capital

Year ended Dec. 31	2010	2009	2008
(Use) source:			
Accounts receivable	**(9)**	114	80
Prepaid expenses	**6**	(7)	3
Income taxes receivable	**17**	(1)	(20)
Inventory	**31**	(42)	(10)
Accounts payable and accrued liabilities	**(15)**	(208)	157
Income taxes payable	**(2)**	(5)	-
Change in non-cash operating working capital	**28**	(149)	210

31. Stock-Based Compensation Plans

At Dec. 31, 2010, the Corporation had two 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. Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada 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 and is offered to all full-time and part-time employees in the U.S.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia below the level of manager. 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.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2010 are shown below:

	Options outstanding			Options exercisable	
Range of exercise prices (per share)	Number outstanding at Dec.31, 2010 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price (per share)	Number exercisable at Dec. 31, 2010 (millions)	Weighted average exercise price (per share)
11.00-17.01	**0.1**	**2.6**	**14.21**	**0.1**	**14.21**
17.02-23.03	**1.2**	**7.5**	**21.33**	**0.4**	**18.83**
23.04-29.05	**0.1**	**0.3**	**27.70**	**0.1**	**27.70**
29.06-35.05	**0.8**	**7.1**	**32.05**	**0.4**	**32.06**
11.00-35.05	**2.2**	**6.6**	**24.94**	**1.0**	**24.55**

The change in the number of options outstanding under the option plans are outlined below:

Year ended Dec. 31	**2010**		2009		2008	
	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)
Outstanding, beginning of year	**1.5**	**26.36**	1.7	26.80	1.2	19.69
Granted	**0.9**	**22.27**	-	-	1.0	32.10
Exercised	**(0.1)**	**16.20**	-	-	(0.3)	20.52
Cancelled or expired	**(0.1)**	**26.61**	(0.2)	26.47	(0.2)	27.96
Outstanding, end of year	**2.2**	**24.94**	1.5	26.36	1.7	26.80

B. Performance Share Ownership Plan

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to grant to employees and directors up to an aggregate of 4.0 million common shares. During 2010, the authorized amount was increased to 6.5 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, cannot exceed 13.0 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, and the ultimate granting of PSOP in any year is at the discretion of TransAlta's Human Resource Committee. Once a participant's PSOP eligibility for an award has been established, 50 per cent of the shares may be released to the participant when the Board of Directors uses share sett lements on the awards, while the remaining 50 per cent will be held in trust for one additional year for employees below vice president level, and for two additional years for employees at the vice president level and above. 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 comparator group. Expense related to this plan is recorded during the period earned, with the corresponding payable recorded in liabilities.

Year ended Dec. 31 *(millions)*	**2010**	2009	2008
Number of awards outstanding, beginning of year	**1.0**	0.9	1.0
Granted	**1.2**	0.5	0.2
Exercised	**(0.2)**	(0.2)	(0.2)
Cancelled or expired	**(0.3)**	(0.2)	(0.1)
Number of awards outstanding, end of year	**1.7**	1.0	0.9

In 2010, pre-tax PSOP compensation expense was $7 million (2009 - $9 million, 2008 - $7 million), which is included in OM&A expense in the Consolidated Statements of Earnings. In 2010, 166,169 common shares were issued at $23.48 per share. In 2009, 224,591 common shares were issued at $24.30 per share. In 2008, 221,855 common shares were issued at $33.35 per share.

C. 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 not 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, 2010, accounts receivable from employees under the plan totalled $2 million (2009 - $3 million).

D. Stock-Based Compensation

At Dec. 31, 2010, the Corporation had 2.2 million outstanding employee stock options (2009 - 1.5 million).

The Corporation uses the fair value method of accounting for awards granted under its stock option plans. On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, 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, 2011 and expire after 10 years. The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model in 2010 and 2008 and the binomial model in 2005 and 2002 using the following assumptions:

	2010	2008	2005	2002
Weighted average fair value per option	**3.67**	6.31	6.84	4.25
Risk-free interest rate (%)	**2.5**	3.6	4.3	5.9
Expected life of the options (years)	**5**	7	10	7
Dividend rate (%)	**5.1**	3.4	5.6	4.9
Volatility in the price of the Corporation's shares (%)	**29.7**	23.2	47.0	28.3

32. 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, 2010. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2010. The last actuarial valuation for funding purposes of the registered plan was Dec. 31, 2009, and the effective date of the next required valuation for funding purposes is Dec. 31, 2012. 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 $62 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 and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2010. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2010.

B. Costs Recognized

The costs recognized during the year on the defined benefit, defined contribution, and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Current service cost	**2**	**2**	**2**	**6**
Interest cost	**21**	**4**	**2**	**27**
Actual return on plan assets	**(28)**	**-**	**-**	**(28)**
Actuarial loss (gain) on accrued benefit obligation	**30**	**8**	**(3)**	**35**
Difference between expected return and actual return on plan assets	**7**	**-**	**-**	**7**
Difference between amortized and actuarial (gain) loss on accrued benefit obligation for the year	**(26)**	**(8)**	**3**	**(31)**
Amortization of net transition asset	**(9)**	**-**	**-**	**(9)**
Defined benefit (income) expense	**(3)**	**6**	**4**	**7**
Defined contribution expense	**19**	**-**	**-**	**19**
Net expense	**16**	**6**	**4**	**26**

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Current service cost	2	1	2	5
Interest cost	22	3	2	27
Actual return on plan assets	(38)	-	-	(38)
Actuarial loss on accrued benefit obligation	36	7	13	56
Difference between expected return and actual return on plan assets	19	-	-	19
Difference between amortized and actuarial gain on accrued benefit obligation for the year	(33)	(6)	(12)	(51)
Amortization of net transition asset	(9)	-	-	(9)
Defined benefit (income) expense	(1)	5	5	9
Defined contribution expense	18	-	-	18
Net expense	17	5	5	27

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 on accrued benefit obligation	(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 the year	50	6	5	61
Past service cost	-	2	-	2
Difference between amortized and actual plan amendments of past service costs for the year	-	(2)	-	(2)
Amortization of net transition asset	(9)	-	-	(9)
Defined benefit (income) expense	(9)	5	3	(1)
Defined contribution expense	17	-	-	17
Net expense	8	5	3	16

In 2010, 2009, and 2008, the entire net expense is related to continuing operations.

C. Status of Plans

The status of the defined benefit and other health and dental benefit plans is as follows:

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Fair value of plan assets	**304**	**4**	**-**	**308**
Accrued benefit obligation	**382**	**66**	**29**	**477**
Funded status - plan deficit	**(78)**	**(62)**	**(29)**	**(169)**
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	**-**	**2**	**2**	**4**
Unamortized transition obligation	**-**	**1**	**-**	**1**
Unamortized net actuarial losses	**103**	**23**	**6**	**132**
Total recognized in the consolidated financial statements:				
Accrued benefit asset (liability)	**25**	**(36)**	**(21)**	**(32)**
Amortization period in years	**15**	**13**	**15**	

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Fair value of plan assets	299	3	-	302
Accrued benefit obligation	358	55	33	446
Funded status - plan deficit	(59)	(52)	(33)	(144)
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	1	2	2	5
Unamortized transition (asset) obligation	(9)	1	-	(8)
Unamortized net actuarial losses	85	15	11	111
Total recognized in the consolidated financial statements:				
Accrued benefit asset (liability)	18	(34)	(20)	(36)
Amortization period in years	14	14	15	

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 other assets and deferred credits and other long-term liabilities.

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Accrued current liabilities	**-**	**4**	**2**	**6**
Other long-term (assets) liabilities	**(25)**	**32**	**19**	**26**
Accrued benefit (asset) liability	**(25)**	**36**	**21**	**32**

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Accrued current liabilities	-	3	2	5
Other long-term (assets) liabilities	(18)	31	18	31
Accrued benefit (asset) liability	(18)	34	20	36

D. Contributions

Expected cash flows on the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2011 (expected)	3	4	3	10
Expected benefit payments				
2011	27	3	3	33
2012	27	3	2	32
2013	27	3	2	32
2014	28	4	2	34
2015	28	4	2	34
2016-2020	141	21	13	175

E. Plan Assets

The plan assets of the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Fair value of plan assets at Dec. 31, 2008	279	3	-	282
Contributions	7	3	2	12
Benefits paid	(26)	(3)	(2)	(31)
Benefits transferred in[1]	4	-	-	4
Effect of translation on U.S. plans	(3)	-	-	(3)
Actual return on plan assets[2]	38	-	-	38
Fair value of plan assets at Dec. 31, 2009	299	3	-	302
Contributions	5	4	3	12
Benefits paid	(26)	(3)	(3)	(32)
Effect of translation on U.S. plans	(2)	-	-	(2)
Actual return on plan assets[2]	28	-	-	28
Fair value of plan assets at Dec. 31, 2010	**304**	**4**	**-**	**308**

1 Transfer of pension assets for addition of employees.

2 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 approximately seven per cent. The pension fund may be invested in a variety of permitted investments, including publicly traded common or preferred 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 targeted asset allocation is 50 per cent equity and 50 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investments 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 defined benefit plan assets by major asset category at Dec. 31, 2010 and 2009 is as follows:

Year ended Dec. 31, 2010 (per cent)	Registered	Supplemental
Equity securities	**51**	**-**
Debt securities	**46**	**-**
Cash and cash equivalents	**3**	**100**
Total	**100**	**100**

Year ended Dec. 31, 2009 (per cent)	Registered	Supplemental
Equity securities	52	-
Debt securities	45	-
Cash and cash equivalents	3	100
Total	100	100

Plan assets do not include any common shares of the Corporation at Dec. 31, 2010. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2010 (2009 - $0.1 million).

The fair value of the total defined benefit plan assets by major asset category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**-**	**147**	**9**	**156**
Debt securities	**-**	**141**	**-**	**141**
Cash and cash equivalents	**7**	**-**	**-**	**7**
Money market investments	**-**	**4**	**-**	**4**
Total	**7**	**292**	**9**	**308**

The fair value of the Canadian defined benefit plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**-**	**138**	**9**	**147**
Debt securities	**-**	**128**	**-**	**128**
Cash and cash equivalents	**3**	**-**	**-**	**3**
Money market investments	**-**	**4**	**-**	**4**
Total	**3**	**270**	**9**	**282**

The fair value of the U.S. defined benefit plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**-**	**9**	**-**	**9**
Debt securities	**-**	**13**	**-**	**13**
Total	**-**	**22**	**-**	**22**

The fair value of the supplemental plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Cash and cash equivalents	**4**	**-**	**-**	**4**
Total	**4**	**-**	**-**	**4**

F. Accrued Benefit Obligation

The accrued benefit obligation on the defined benefit and other health and dental benefit plans is as follows:

	Registered	Supplemental	Other	Total
Accrued benefit obligation as at Dec. 31, 2008	324	47	20	391
Current service cost	2	1	2	5
Interest cost	22	3	2	27
Benefits paid	(26)	(3)	(2)	(31)
Benefits transferred in [1]	4	-	-	4
Effect of translation on U.S. plans	(4)	-	(2)	(6)
Actuarial loss	36	7	13	56
Accrued benefit obligation as at Dec. 31, 2009	358	55	33	446
Current service cost	2	2	2	6

Interest cost	21	4	2	27
Benefits paid	(26)	(3)	(3)	(32)
Curtailment	(2)	-	(1)	(3)
Effect of translation on U.S. plans	(1)	-	(1)	(2)
Actuarial loss (gain)	30	8	(3)	35
Accrued benefit obligation as at Dec. 31, 2010	**382**	**66**	**29**	**477**

1 Transfer of accrued benefit obligation for addition of employees.

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation on the defined benefit and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2010 (per cent)	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	**5.2**	**5.3**	**5.0**
Rate of compensation increase	**3.0**	**3.0**	**-**
Benefit cost for year ended Dec. 31			
Discount rate	**6.0**	**6.0**	**5.7**
Rate of compensation increase	**3.0**	**3.0**	**-**
Expected rate of return on plan assets	**7.1**	**-**	**-**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	**-**	**-**	**8.5-9.0**[1]
Dental care cost escalation	**-**	**-**	**4.0**
Provincial health care premium escalation	**-**	**-**	**6.0**

Year ended Dec. 31, 2009 (per cent)	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	6.0	6.0	5.7
Rate of compensation increase	3.0	3.0	-
Benefit cost for year ended Dec. 31			
Discount rate	7.2	7.3	7.0
Rate of compensation increase	3.2	3.3	-
Expected rate of return on plan assets	7.1	-	-
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	-	-	9.2-10.5[1]
Dental care cost escalation	-	-	4.0
Provincial health care premium escalation	-	-	6.0

1 Decreasing gradually to five per cent by 2018 for Canadian plans and by 2017-2020 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.

H. Sensitivity Analysis

The following changes would occur in the defined benefit and other health and dental benefit plans if there was a change of +/- one percentage point in the discount rate, trend rate, or expected rate of return on plan assets:

Canadian plans:

Year ended Dec. 31, 2010	Registered	Supplemental	Other
1% increase in the discount rate			
Impact on 2010 accrued benefit obligation	**(33)**	**(8)**	**(1)**
Impact on 2011 estimated expense under IFRS	**1**	**-**	**-**
1% decrease in the discount rate			
Impact on 2010 accrued benefit obligation	**39**	**10**	**2**
Impact on 2011 estimated expense under IFRS	**(1)**	**-**	**-**
1% increase in the trend rate			
Impact on 2010 accrued benefit obligation	**-**	**-**	**1**
1% decrease in the trend rate			
Impact on 2010 accrued benefit obligation	**-**	**-**	**(1)**
1% increase in the expected rate of return on plan assets			
Impact on 2011 estimated expense under IFRS	**(3)**	**-**	**-**
1% decrease in the expected rate of return on plan assets			
Impact on 2011 estimated expense under IFRS	**3**	**-**	**-**

U.S. plans:

Year ended Dec. 31, 2010	Pension	Other
1% increase in the discount rate		
Impact on 2010 accrued benefit obligation	**(2)**	**(1)**
Impact on 2011 estimated expense under IFRS	**-**	**-**
1% decrease in the discount rate		
Impact on 2010 accrued benefit obligation	**3**	**1**
Impact on 2011 estimated expense under IFRS	**-**	**-**
1% increase in the trend rate		

Impact on 2010 accrued benefit obligation	-	1
1% decrease in the trend rate		
Impact on 2010 accrued benefit obligation	-	(1)
1% increase in the expected rate of return on plan assets		
Impact on 2011 estimated expense under IFRS	-	-
1% decrease in the expected rate of return on plan assets		
Impact on 2011 estimated expense under IFRS	-	-

33. Joint Ventures

Joint ventures at Dec. 31, 2010 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, operated by Canadian Utilities Limited
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, 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 U.S. operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta operated by Capital Power Corporation
Wailuku	50%	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company
Keephills 3	50%	Coal-fired plant under construction in Alberta. The plant is being developed jointly with Capital Power Corporation and will be operated by TransAlta
Taylor Hydro	50%	Hydro facility in Alberta operated by TransAlta
Soderglen	50%	Wind generation facilities in Alberta operated by TransAlta
Pingston	50%	Hydro facility in British Columbia operated by TransAlta
Project Pioneer	25%	Carbon capture and storage facility operated by TransAlta

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:

	2010	2009	2008
Results of operations			
Revenues	**449**	539	619
Expenses	**(371)**	(409)	(494)
Non-controlling interests	**(7)**	(34)	(55)
Proportionate share of net earnings	**71**	**96**	**70**
Cash flows			
Cash flow from operations	**133**	111	273
Cash flow used in investing activities	**(211)**	(168)	(376)
Cash flow (used in) from financing activities	**(28)**	(60)	30
Proportionate share of decrease in cash and cash equivalents	**(106)**	**(117)**	**(73)**
Financial position			
Current assets	**139**	147	166
Long-term assets	**2,512**	2,371	2,144
Current liabilities	**(87)**	(114)	(202)
Long-term liabilities	**(374)**	(426)	(503)
Non-controlling interests	**(301)**	(325)	(351)
Proportionate share of net assets	**1,889**	**1,653**	**1,254**

34. Subsequent Events

TransAlta has evaluated subsequent events through to the date the consolidated financial statements were issued. TransAlta has not evaluated any subsequent events after that date.

Sundance Unit 1 and 2 Outage

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of the Sundance facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units were unavailable as inspections were carried out to determine the scope of repairs that may be needed. The units cannot be restarted without inspection and approval from the Alberta Boiler Safety Association. As a result of the outage, production was reduced by 182 gigawatt hours for the year ended Dec. 31, 2010.

Under the terms of the PPA for these units, TransAlta notified the PPA Buyer and the Balancing Pool of a force majeure event. Under force majeure, the Corporation is entitled to receive PPA capacity payments and is protected from having to pay penalties for the units' lack of availability, to the extent the event meets the force majeure criteria set out in the PPA.

On Feb. 8, 2011, the Corporation announced that it had issued a notice of termination for destruction on the Sundance 1 and 2 coal-fired generation units under the terms of the PPA. This action was based on the determination that the physical state of the boilers is such that the units cannot be economically restored to service under the terms of the PPA. Under the PPA, termination for destruction permits the recovery of the net book value specified in the PPA.

On Feb. 18, 2011, the PPA Buyer provided notice that it intends to dispute the notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. Although no assurance can be given as to the ultimate outcome of these

matters, TransAlta believes that they will be resolved in the Corporation's favour. TransAlta remains committed to continuing to work with the PPA Buyer and the Balancing Pool under the processes established within the PPA.

Exhibit 13.4

TRANSALTA CORPORATION

RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

DECEMBER 31, 2010

INDEPENDENT AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

To the Board of Directors of TransAlta Corporation

On February 23, 2011, we reported on the consolidated balance sheets of TransAlta Corporation as at December 31, 2010 and 2009 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, 2010 (the "Consolidated Financial Statements") which are included in the Annual Report on Form 40-F.

In connection with our audits conducted in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) of the Consolidated Financial Statements, we also have audited the related supplemental note entitled "Reconciliation to United States Generally Accepted Accounting Principles" included in the Form 40-F. This supplemental note is the responsibility of the Corporation's management. Our responsibility is to express an opinion on this supplemental note based on our audit.

In our opinion, such supplemental note, when considered in relation to the Consolidated Financial Statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in the supplemental note entitled "Reconciliation to United States Generally Accepted Accounting Principles", the Corporation changed its method of accounting for business combinations and non-controlling interest by the adoption of the guidance originally issued by the Financial Accounting Standards Board (FASB) Statement No. 141(R), Business Combinations (codified in FASB Accounting Standards Codification (ASC) Topic 805, Business Combinations), and FASB Statement No. 160, Non Controlling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51 (codified in FASB ASC Topic 810, Consolidation), both effective January 1, 2009.

Calgary, Canada
February 23, 2011

Signed "Ernst & Young LLP"
Chartered Accountants

RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

This financial information has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"), which, in most respects, conform to the United States Generally Accepted Accounting Principles ("U.S. GAAP"). This information does not include all of the disclosures included in TransAlta Corporation's annual consolidated financial statements. Accordingly, this information should be read in conjunction with the Corporation's most recent annual audited consolidated financial statements. All amounts herein are in millions of Canadian dollars unless otherwise noted.

The material differences to reconcile Canadian GAAP to U.S. GAAP are described below:

A. EARNINGS, EARNINGS PER SHARE ("EPS") AND COMPREHENSIVE INCOME INFORMATION

Year ended Dec. 31	*Reconciling items*	**2010**	2009[1]	2008
Net earnings attributable to TransAlta - Canadian GAAP		**219**	181	235
Net earnings attributable to non-controlling interests - Canadian GAAP		**20**	38	61
Embedded derivative, net of tax	*X*	**(19)**	(21)	-
Pension cost, net of tax	*V*	**(6)**	(6)	(6)
Depreciation, net of tax	*IX*	**(1)**	1	-
Start-up costs, net of tax	*III*	**-**	5	-
Share-based payments, net of tax	*VII*	**-**	(1)	1
Sale of minority interest in Kent Hills	*VIII*	**-**	(1)	-
Acquisition-related costs, net of tax	*IX*	**-**	(26)	-
Net earnings - U.S. GAAP		**213**	170	291
Net earnings attributable to non-controlling interests - U.S. GAAP		**20**	38	61
Net earnings attributable to TransAlta - U.S. GAAP		**193**	132	230
Preferred share dividends - Canadian & U.S. GAAP		**1**	-	-
Net earnings attributable to common shareholders - U.S. GAAP		**192**	132	230
Weighted average number of common shares outstanding in the period		**219**	201	199
Net earnings attributable to common shareholders per share, basic and diluted - U.S. GAAP		**0.88**	0.66	1.16

[1] Certain comparative figures have been adjusted. See Note D IX.

Year ended Dec. 31	*Reconciling items*	**2010**	2009[1]	2008
Net earnings - U.S. GAAP		**213**	170	291
Other comprehensive income attributable to TransAlta - Canadian GAAP		**14**	65	306
Employee future benefits	*V*	**(16)**	(22)	(18)
Cash flow hedges	*I*	**(12)**	(12)	7
Cash flow hedges - non-controlling interests	*XII*	**(16)**	-	-
Total other comprehensive income (loss) - U.S. GAAP		**(30)**	31	295
Comprehensive income - U.S. GAAP		**183**	201	586
Comprehensive income attributable to non-controlling interests - U.S. GAAP		**4**	38	61
Comprehensive income attributable to TransAlta - U.S. GAAP		**179**	163	525

[1] Certain comparative figures have been adjusted. See Note D IX.

B. BALANCE SHEET INFORMATION

		Dec 31, 2010		Dec. 31, 2009	
	Reconciling items	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP [1]
Assets					
Property, plant, and equipment, net	*I, IX*	**7,577**	**7,577**	7,559	7,462
Goodwill	*IX*	**517**	**492**	434	496
Net risk management assets (including current portion)	*X*	**315**	**259**	245	216
Liabilities					
Accounts payable and accrued liabilities *IX*		**503**	**503**	521	523
Deferred credits and other liabilities	*V*	**169**	**316**	147	265
Net future or deferred income tax liabilities (including current portion)	*I, II, V, X, IX*	**467**	**415**	473	409
Non-controlling interests	*XIII*	**435**	**-**	478	-
Equity					
Contributed surplus	*IV*	**-**	**133**	-	133
Retained earnings	*IV, V, IX, X*	**533**	**310**	634	437
Accumulated other comprehensive income	*I, V*	**140**	**55**	126	69
Non-controlling interests	*XIII*	**-**	**435**	-	478

[1] Certain comparative figures have been adjusted. See Note D IX.

C. ACCUMULATED OTHER COMPREHENSIVE INCOME (AOCI)

The components of AOCI under Canadian GAAP and U.S. GAAP are as follows:

		Dec 31, 2010		Dec. 31, 2009	
	Reconciling items	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax		**(92)**	**(92)**	(63)	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	*I*	**232**	**232**	189	201
Pensions, net of tax	*V*	**-**	**(85)**	-	(69)
Accumulated other comprehensive income		**140**	**55**	126	69

D. RECONCILING ITEMS

I. Cash Flow Hedges

Under Canadian GAAP, certain gains and losses on derivatives designated as cash flow hedges can be included in the carrying amount of the underlying hedged item. Under U.S. GAAP, these gains and losses must remain in Other Comprehensive Income ("OCI"), and similar to Canadian GAAP, are recognized into net earnings in the same period during which the underlying hedged item affects net earnings.

II. Income Taxes

Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP.

Deferred income taxes under U.S. GAAP are as follows:

	Dec 31, 2010	Dec. 31, 2009 [1]
Future income tax liabilities (net) under Canadian GAAP	**(467)**	(473)
Pensions	**38**	32
Cash flow hedges	**-**	(4)
Embedded derivatives	**14**	7

Purchase price allocation adjustment	**-**	29
Deferred income tax liabilities (net) under U.S. GAAP	**(415)**	(409)

Comprised of the following:

	Dec 31, 2010	Dec. 31, 2009
Long-term deferred income tax assets	**296**	273
Current deferred income tax liabilities	**(77)**	(45)
Long-term deferred income tax liabilities	**(634)**	(637)
	(415)	(409)

(1) Comparative figures have been adjusted. See Note D IX

In 2007, TransAlta adopted Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"), now contained in FASB Accounting Standards Codification ("ASC") Topic 740, *Income Taxes*. Unrecognized tax benefits decreased by $78 million for the year ended Dec. 31, 2010 ($9 million for the year ended Dec. 31, 2009), resulting in a balance as of Dec. 31, 2010 of $33 million ($111 million as of Dec. 31, 2009).

The reconciliation between the opening and closing unrecognized tax benefits is provided below:

Accounting for Uncertainty in Income Taxes

Balance, Dec. 31, 2008	120
Decrease as a result of settlements with taxation authorities	(12)
Increase as a result of tax positions taken	3
Balance, Dec. 31, 2009	111
Decrease as a result of settlements with taxation authorities	(92)
Increase as a result of tax positions taken	14
Balance, Dec 31, 2010	**33**

These unrecognized tax benefits, if recognized, would affect the effective tax rate. No material increase or decrease in unrecognized tax benefits is expected in the next 12 months.

The Corporation's income tax filings are subject to audit examination by taxation authorities. As at Dec. 31, 2010, the tax years that remain subject to examination in major jurisdictions are: 2003 – 2009 in Canada, 2006 – 2009 in the U.S., 2003 – 2008 in Mexico, and 1996 – 2009 in Australia.

The Corporation's accounting policy is to include penalties and interest as a component of income tax expense. As at Dec. 31, 2010, $8 million of accrued interest and penalties is included in deferred income tax liabilities ($5 as at Dec. 31, 2009).

III. Start-Up Costs

Costs associated with start up activities were previously deferred and amortized under Canadian GAAP, whereas under U.S. GAAP they are expensed in the year incurred.

IV. Contributed Surplus

In 1998, the Corporation transferred generation assets to one of its subsidiaries, TA Cogen. TA Power, an unrelated entity, concurrently subscribed for a minority interest in TA Cogen. The fair value paid by TA Cogen for the assets exceeded their historical carrying values. For Canadian GAAP, the Corporation recognized a portion of this difference, to the extent it was funded by TA Power's investment in TA Cogen, as a gain on disposition. TA Power held an option to resell its interest in TA Cogen to the Corporation in 2018, and in 2003, TA Power's option to resell these units was eliminated and the unamortized balance of the gain was recognized in income.

Under FASB Accounting Research Bulletin ("ARB") No. 51, *Consolidated Financial Statements*, now contained in FASB ASC Topic 810, *Consolidation*, the option initially held by TA Power to potentially resell TA Cogen units to the Corporation

in 2018 causes the excess of the consideration paid by TA Power over the Corporation's historical carrying value in these assets to be characterized as contributed surplus.

V. Pension Plans

Under Financial Accounting Standards No. 158 ("SFAS 158"), *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, now contained in FASB ASC Topic 715, *Compensation – Retirement Benefits*, actuarial gains and losses recognized on pension plans and postretirement benefits are recorded to OCI and are charged to earnings as services are rendered. Under Canadian GAAP, actuarial gains or losses exceeding a certain threshold are charged to earnings as services are rendered. Consequently, the pension benefit cost under U.S. GAAP is impacted by the amounts amortized through AOCI which does not affect the pension benefit cost under Canadian GAAP. The pension benefit cost is adjusted for this difference.

Pre-tax amounts recognized in AOCI are as follows:

Year ended Dec. 31	**2010**			2009		
	Pension benefits	**Other benefits**	**Total**	Pension benefits	Other benefits	Total
Net actuarial loss	**(106)**	**(6)**	**(112)**	(80)	(11)	(91)
Past service cost	**(2)**	**(2)**	**(4)**	(2)	(2)	(4)
Difference between Canadian and U.S. GAAP included in AOCI	**(108)**	**(8)**	**(116)**	(82)	(13)	(95)

Pre-tax amounts recorded in Other Comprehensive Income ("OCI") were as follows:

As at Dec. 31	**2010**		
	Pension benefits	**Other benefits**	**Total**
Amortization of net loss from AOCI to net income	**(5)**	**(1)**	**(6)**
Net actuarial loss (gain)	**31**	**(4)**	**27**

The estimated net actuarial loss and prior service cost for defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal

year is $4 million. The estimated net actuarial loss and prior service cost for other defined benefit postretirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $1 million.

VI. Joint Ventures

In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the United States Security and Exchange Commission ("SEC"), the Corporation, as a Foreign Private Issuer, has elected to account for incorporated joint ventures using the proportionate consolidation method. See disclosure of the amounts proportionately consolidated in Note 33 of the Corporation's 2010 annual audited consolidated financial statements.

VII. Share-Based Payments

Under U.S. GAAP FAS 123(R), now contained in FASB ASC Topic 718, *Compensation – Stock Compensation*, the Corporation is required to measure the cost of employee services received in exchange for an award of cash-settled instruments based on the current fair value of the award, whereas under Canadian GAAP, measurement is based on intrinsic value. The fair value of the award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the service period will be recognized as compensation expense over that period. The difference in measurement had no impact on the financial information presented herein as it was immaterial.

VIII. Sale of Minority Interest

During the fourth quarter of 2010, the Corporation sold a 17 per cent interest in its Kent Hills expansion project to Natural Forces Technologies Inc. ("NFT") and realized a pre-tax gain of less than $1 million under Canadian GAAP. During the second quarter of 2009, the Corporation sold a 17 per cent interest in its Kent Hills project to NFT and recorded a pre-tax gain of $1 million in accordance with Canadian GAAP. FAS 160, *Noncontrolling Interests in Consolidated Financial Statements*, now contained in FASB ASC Topic 810, *Consolidation*, requires that any difference between the fair value of the consideration received and the amount by which the non-controlling interest is adjusted should be recognized in equity attributable to the parent. As at Dec. 31, 2009, $1 million of other income has been reclassified and included in retained earnings.

IX. Acquisition of Canadian Hydro Developers

On Oct. 23, 2009, TransAlta completed the acquisition of 87 percent of the outstanding common shares of Canadian Hydro Developers. On Nov. 4, 2009, TransAlta acquired the remaining 13 percent of the issued and outstanding shares. The acquisition was accounted for under U.S. GAAP, FASB ASC Topic 805, *Business Combinations*. Acquisition-related costs of $26 million, net of tax, were expensed in 2009 under U.S. GAAP rather than capitalized, as permitted under Canadian GAAP. The 2009 preliminary purchase price allocation was based on best estimates by TransAlta's management. During the fourth quarter of 2010, Management updated the preliminary assumptions used in the purchase price allocation and as permitted under Canadian GAAP, applied the adjustments retrospectively, without restatement, as at Dec. 31, 2010. FASB ASC Topic 805, *Business Combinations* requires that any adju stments identified during the measurement period be made retrospectively as at the acquisition date. Accordingly, the 2009 U.S. GAAP Balance Sheet and the 2009 U.S. GAAP Statement of Net Earnings and Comprehensive Income have been restated, as follows:

Balance Sheet	Dec. 31, 2009 Increase (Decrease)
Assets:	
Property, plant, and equipment	**(103)**
Intangible assets	**(10)**
Goodwill	**87**
	(26)
Liabilities:	
Current liabilities	**2**
Deferred income tax liabilities	**(29)**
	(27)
Net earnings impact	**1**

The net earnings impact is as a result of reduced depreciation and amortization expense, net of tax.

X. Embedded Derivatives

Under U.S. GAAP, FASB ASC Topic 815, *Derivatives and Hedging*, an embedded foreign currency derivative instrument is required to be separated from its host contract when the currency in which the price of the related good or service that is acquired or delivered is not routinely used in international commerce and is not the functional currency of the parties to the contract. Under Canadian GAAP, the separation of the embedded derivative is not required if the currency of the embedded foreign currency derivative instrument is commonly used in contracts to purchase or sell non-financial items in the economic environment in which the transaction takes place. As a result of the difference in standards for recognizing embedded foreign currency derivatives, TransAlta is required to separately record an embedded derivative under U.S. GAAP. As at Dec. 31, 2010, $56 million (Dec. 31 , 2010 - $29 million) was recognized as a risk management liability. During the year ended Dec. 31, 2010, the loss on the foreign currency derivative instrument increased by $27 million (Dec. 31, 2009 - $29 million) and an unrealized loss of $19 million, net of tax, (Dec. 31, 2009 - $21 million) has been recognized in net earnings.

XI. Private Equities

TransAlta holds private equity funds in its Canadian pension plan that are redeemable on maturity of the related ten year agreements. These private equities seek to provide a return to investors with the following strategies: Lumira Capital I Limited Partnership holds a mixture of public and private companies in the life sciences sector; Novacap II, L.P. operates a venture capital business specializing in the manufacturing and technology sectors; and Northleaf Global Private Equity Investors I seeks to build a diversified portfolio of investments in private equity funds managed by fund mangers with a focus on investments in venture capital and buyout funds, principally in North America and Western Europe.

XII. Non-Controlling Interests in Other Comprehensive Income

U.S. GAAP, FASB ASC Topic 810, *Consolidation*, requires that comprehensive income or loss be reported at the consolidated entity amount and attributed to the parent and the non-controlling interest. Under Canadian GAAP, comprehensive income or loss is reported as only the parent's share.

XIII. Non-Controlling Interests - Presentation

Under U.S. GAAP, FASB ASC Topic 810, *Consolidation*, the amount of non-controlling interest is presented on the Balance Sheet within equity, separate from the parent's equity, whereas under Canadian GAAP, non-controlling interest is presented as a separate item on the Balance Sheet, outside of equity.

E. CHANGES IN ACCOUNTING STANDARDS

I. Current Accounting Changes

1. On Jan. 1, 2010, the Corporation adopted Accounting Standards Update ("ASU") No. 2009-16, *Accounting for Transfers of Financial Assets*, which amends the codification of FAS 166 issued in June 2009 and is now contained in FASB ASC Topic 860, *Transfers and Servicing*. Statement 166 is a revision to Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. This amendment requires additional disclosures on transfers of financial assets, including securitization transactions and continued exposure to the risks related to transferred financial assets. It also eliminates the concept of a "qualifying special-purpose entity", and provides requirements for derecognizing financial assets. The implementation of this ASU did not have an impact on this financial information.

2. On Jan. 1, 2010, the Corporation adopted ASU No. 2009-17, *Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities* , which amends the codification of FAS 167 issued in June 2009 and is now contained in FASB ASC Topic 810, *Consolidation*. Statement 167 is a revision to FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities* and provides guidance on how to determine when an entity that is insufficiently capitalized or is not controlled through voting (or similar) rights should be consolidated. The implementation of this ASU did not have an impact on this financial information.

3. On Jan.1, 2010, the Corporation adopted ASU No. 2010-06, *Improving Disclosures about Fair Value Measurements*, now contained in FASB ASC Topic 820, *Fair Value Measurements and Disclosures*. This amendment requires new disclosures regarding the amounts, and descriptions, of significant transfers in and out of Level 1 and 2 fair value measurements. It also clarifies existing disclosures regarding i) the level of disaggregation of fair value measurement disclosures; and ii) inputs and valuation techniques. The implementation of this ASU did not have an impact on this financial information.

4. On Jan. 1, 2010, the Corporation adopted ASU No. 2010-08, *Technical Corrections to Various Topics* . The amendments in this Update do not change U.S. GAAP, but rather eliminate inconsistencies and outdated provisions and provide clarifications, where needed. The implementation of this ASU did not have an impact on this financial information.

5. On Feb. 24, 2010, the Corporation adopted ASU No. 2010-09, *Amendments to Certain Recognition and Disclosure Requirements*, now contained FASB ASC 855, *Subsequent Events*. The Update requires subsequent events to be evaluated through the date that the financial statements are issued. The implementation of this ASU did not have an impact on this financial information.

6. On July 1, 2010, the Corporation adopted ASU No. 2010-11, *Scope Exception Related to Embedded Credit Derivatives*, now contained in FASB ASC Topic 815, *Derivatives and Hedging*, which clarify the scope exception for embedded credit derivative features related to the transfer of credit risk in the form of subordination of one financial instrument to another. The implementation of this ASU did not have an impact on this financial information.

7. On July 21, 2010, the Corporation adopted the year end disclosure requirements in ASU No. 2010-20, *Disclosures about the Credit Qualify of Financing Receivables and the Allowance for Credit Losses,* now contained in FASB ASC Topic 310, *Receivables*. The implementation of this ASU did not have an impact on this financial information.

II. Future Accounting Changes

There are a number of issued ASU's that may potentially affect the Corporation's future interim and annual reconciliations to U.S. GAAP. However, TransAlta has adopted International Financial Reporting Standards effective Jan. 1, 2011 and as a result, will no longer be required to prepare a reconciliation to U.S. GAAP.

Exhibit 23.1



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CONSENT OF INDEPENDENT AUDITORS

We consent to the use of our reports dated February 23, 2011 with respect to the consolidated financial statements of TransAlta Corporation (the "Corporation") as at December 31, 2010 and 2009 and for each of the years in the three-year period ended December 31, 2010, and internal control over financial reporting as of December 31, 2010 of TransAlta Corporation, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) for 2010.

We also consent to the use of our audit report dated February 23, 2011 to the Board of Directors of the Corporation with respect to the Reconciliation to United States Generally Accepted Accounting Principles as at December 31, 2010 and 2009 and for each of the years in the three -year period ended December 31, 2010, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) for 2010.

We also consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-72454 and No. 333-101470) pertaining to TransAlta Corporation's Share Option Plan

(2) Registration Statement (Form F-10 No. 333-170465 and No. 333-162418) pertaining to the registration of Debt and Equity Securities of TransAlta Corporation

of our reports dated February 23, 2011, with respect to the consolidated financial statements of TransAlta Corporation as at December 31, 2010 and 2009 and for each of the years in the three- year period ended December 31, 2010, internal control over financial reporting as of December 31, 2010 of TransAlta Corporation and the Reconciliation to United States Generally Accepted Accounting Principles as of December 31, 2010 and 2009 and for each of the years in the three- year period ended December 31, 2010, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) of TransAlta Corporation for the year ended December 31, 2010.

signed "Ernst & Young LLP"

Calgary, Alberta
February 23, 2011

Chartered Accountants

Exhibit 31.1

Certifications

I, Stephen G. Snyder, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

February 24, 2011

/s/ Stephen G. Snyder
Stephen G. Snyder
President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Brett Gellner, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

February 24, 2011

/s/ Brett Gellner
Brett Gellner
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Stephen G. Snyder, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Stephen G. Snyder
Stephen G. Snyder
President and Chief Executive Officer

Dated: February 24, 2011.

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian Burden, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Brett Gellner
Brett Gellner
Chief Financial Officer

Dated: February 24, 2011.

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.