TransAlta Consolidated Financial Statements

December 31, 2012

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, TransAlta 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 ("the Board") 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.

Dawn Farrell
President and Chief Executive Officer

Brett Gellner
Chief Financial Officer

February 26, 2013

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 Corporation.

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 and Genesee Unit 3 joint ventures and equity accounts for the CE Generation, LLC ("CE Gen") and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures in accordance with International Financial Reporting Standards ("IFRS"). 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 2012 consolidated financial statements of TransAlta Corporation included $918 million and $883 million of total and net assets, respectively, as of December 31, 2012, and $208 million and $49 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 December 31, 2012, 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 December 31, 2012, 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.

Dawn Farrell
President and Chief Executive Officer

Brett Gellner
Chief Financial Officer

February 26, 2013

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, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the corporation's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the CE Gen, Sheerness, Wailuku, and Genesee Unit 3 joint ventures, which are included in the 2012 consolidated financial statements of the Corporation and constituted $918 million and $883 million of total and net assets, respectively, as of December 31, 2012, and $208 million and $49 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the CE Gen, Sheerness, Wailuku, and Genesee Unit 3 joint ventures.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, 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 statements of financial position of TransAlta Corporation as at December 31, 2012 and 2011 and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2012 and our report dated February 26, 2013, expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 26, 2013

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 statements of financial position as at December 31, 2012 and 2011, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2012, 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 International Financial Reporting Standards as issued by the International Accounting Standards Board, 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 auditors consider 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, 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, 2012 and 2011, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

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, 2012, 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 26, 2013 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 26, 2013

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2012**	2011	2010
Revenues *(Note 9)*	**2,262**	2,663	2,673
Fuel and purchased power *(Note 8)*	**809**	947	1,185
Gross margin	**1,453**	1,716	1,488
Operations, maintenance, and administration *(Note 8)*	**493**	545	510
Depreciation and amortization	**509**	482	464
Asset impairment charges *(Note 11)*	**324**	17	28
Inventory writedown *(Note 19)*	**44**	–	–
Restructuring charges *(Note 4)*	**13**	–	–
Taxes, other than income taxes	**28**	27	27
Operating income	**42**	645	459
Finance lease income *(Notes 5 and 9)*	**16**	8	8
Equity income (loss) *(Note 10)*	**(15)**	14	7
Sundance Units 1 and 2 arbitration *(Note 7)*	**(254)**	–	–
Gain on sale of assets *(Note 5)*	**3**	16	–
Other income	**1**	2	–
Foreign exchange gain (loss)	**(9)**	(3)	8
Gain on sale of (reserve on) collateral *(Note 6)*	**15**	(18)	–
Net interest expense *(Notes 12 and 17)*	**(242)**	(215)	(178)
Earnings (loss) before income taxes	**(443)**	449	304
Income tax expense *(Note 13)*	**103**	106	24
Net earnings (loss)	**(546)**	343	280
Net earnings (loss) attributable to:			
TransAlta shareholders	**(583)**	305	256
Non-controlling interests *(Note 14)*	**37**	38	24
	(546)	343	280
Net earnings (loss) attributable to TransAlta shareholders	**(583)**	305	256
Preferred share dividends *(Note 29)*	**31**	15	1
Net earnings (loss) attributable to common shareholders	**(614)**	290	255
Weighted average number of common shares outstanding in the year *(millions)*	**235**	222	219
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 28)*	**(2.61)**	1.31	1.16

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2012**	2011	2010
Net earnings (loss)	**(546)**	343	280
Other comprehensive income (loss)			
Gains (losses) on translating net assets of foreign operations[1]	**(23)**	32	(57)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**13**	(33)	33
Reclassification of gains on translation of foreign operations to net earnings, net of tax[3]	**–**	–	(3)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[4]	**(14)**	(103)	147
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax[5]	**5**	–	8
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[6]	**(6)**	(177)	(129)
Net actuarial losses on defined benefit plans, net of tax[7]	**(27)**	(26)	(20)
Other comprehensive loss	**(52)**	(307)	(21)
Comprehensive income (loss)	**(598)**	36	259
Total comprehensive income (loss) attributable to:			
Common shareholders	**(627)**	18	252
Non-controlling interests	**29**	18	7
	(598)	36	259

1 Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – nil, 2010 – nil).

2 Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – 5 recovery, 2010 – 6 expense).

3 Net of income tax of nil for the year ended Dec. 31, 2012 (2011 – nil, 2010 – nil).

4 Net of income tax expense of 3 for the year ended Dec. 31, 2012 (2011 – 7 recovery, 2010 – 87 expense).

5 Net of income tax recovery of 2 for the year ended Dec. 31, 2012 (2011 – nil, 2010 – 3 recovery).

6 Net of income tax expense of 20 for the year ended Dec. 31, 2012 (2011 – 94 expense, 2010 – 65 expense).

7 Net of income tax recovery of 10 for the year ended Dec. 31, 2012 (2011 – 9 recovery, 2010 – 7 recovery).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2012**	2011
Cash and cash equivalents *(Note 18)*	**27**	49
Accounts receivable *(Notes 15, 16 and 17)*	**597**	541
Current portion of finance lease receivable *(Notes 9 and 16)*	**2**	3
Collateral paid *(Notes 16 and 17)*	**19**	45
Prepaid expenses	**7**	8
Risk management assets *(Notes 16 and 17)*	**201**	391
Inventory *(Note 19)*	**82**	85
Income taxes receivable *(Notes 13 and 20)*	**3**	2
	938	1,124
Investments *(Note 10)*	**172**	193
Long-term receivable *(Note 6)*	**–**	18
Finance lease receivable *(Notes 9 and 16)*	**357**	42
Property, plant, and equipment *(Notes 21 and 40)*		
Cost	**11,481**	11,386
Accumulated depreciation	**(4,437)**	(4,115)
	7,044	7,271
Goodwill *(Notes 22 and 40)*	**447**	447
Intangible assets *(Notes 23 and 40)*	**284**	276
Deferred income tax assets *(Note 13)*	**50**	169
Risk management assets *(Notes 16 and 17)*	**69**	99
Other assets *(Notes 24 and 40)*	**90**	90
Total assets	**9,451**	9,729
Accounts payable and accrued liabilities *(Notes 16 and 17)*	**495**	463
Decommissioning and other provisions *(Notes 4 and 25)*	**33**	99
Collateral received *(Notes 16 and 17)*	**2**	16
Risk management liabilities *(Notes 16 and 17)*	**167**	208
Income taxes payable	**6**	22
Dividends payable *(Notes 16, 17, 28, and 29)*	**75**	67
Current portion of long-term debt *(Notes 16, 17, and 26)*	**607**	316
	1,385	1,191
Long-term debt *(Notes 16, 17, and 26)*	**3,610**	3,721
Decommissioning and other provisions *(Note 25)*	**279**	283
Deferred income tax liabilities *(Note 13)*	**430**	484
Risk management liabilities *(Notes 16 and 17)*	**106**	142
Deferred credits and other long-term liabilities *(Note 27)*	**301**	281
Equity		
Common shares *(Note 28)*	**2,726**	2,273
Preferred shares *(Note 29)*	**781**	562
Contributed surplus	**9**	9
Retained earnings (deficit)	**(358)**	527
Accumulated other comprehensive loss *(Note 30)*	**(148)**	(102)
Equity attributable to shareholders	**3,010**	3,269
Non-controlling interests *(Note 14)*	**330**	358
Total equity	**3,340**	3,627
Total liabilities and equity	**9,451**	9,729

Contingencies *(Notes 36 and 39)*

Commitments *(Notes 17 and 38)*

See accompanying notes.

On behalf of the Board:

Gordon D. Giffin
Director

William D. Anderson
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Retained earnings (deficit)	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2010	2,204	293	7	431	185	3,120	431	3,551
Net earnings	–	–	–	305	–	305	38	343
Other comprehensive loss:								
Net losses on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	(1)	(1)	–	(1)
Net losses on derivatives designated as cash flow hedges, net of tax	–	–	–	–	(260)	(260)	(20)	(280)
Net actuarial losses on defined benefit plans, net of tax	–	–	–	–	(26)	(26)	–	(26)
Total comprehensive income						18	18	36
Common share dividends	–	–	–	(194)	–	(194)	–	(194)
Preferred share dividends	–	–	–	(15)	–	(15)	–	(15)
Distributions to non-controlling interests	–	–	–	–	–	–	(91)	(91)
Common shares issued	69	–	–	–	–	69	–	69
Preferred shares issued	–	269	–	–	–	269	–	269
Effect of share-based payment plans	–	–	2	–	–	2	–	2
Balance, Dec. 31, 2011	2,273	562	9	527	(102)	3,269	358	3,627
Net earnings (loss)	–	–	–	(583)	–	(583)	37	**(546)**
Other comprehensive loss:								
Net losses on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	(10)	(10)	–	**(10)**
Net losses on derivatives designated as cash flow hedges, net of tax	–	–	–	–	(9)	(9)	(6)	**(15)**
Net actuarial losses on defined benefit plans, net of tax	–	–	–	–	(27)	(27)	–	**(27)**
Total comprehensive income (loss)						(629)	31	**(598)**
Common share dividends	–	–	–	(271)	–	(271)	–	**(271)**
Preferred share dividends	–	–	–	(31)	–	(31)	–	**(31)**
Distributions to non-controlling interests	–	–	–	–	–	–	(59)	**(59)**
Common shares issued	453	–	–	–	–	453	–	**453**
Preferred shares issued	–	219	–	–	–	219	–	**219**
Balance, Dec. 31, 2012	**2,726**	**781**	**9**	**(358)**	**(148)**	**3,010**	**330**	**3,340**

1 Refer to Note 30 for details on components of, and changes in, Accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2012**	2011	2010
Operating activities			
Net earnings	**(546)**	343	280
Depreciation and amortization *(Note 40)*	**564**	532	511
Gain on sale of assets *(Note 5)*	**(3)**	(16)	–
Accretion of provisions *(Note 25)*	**17**	19	18
Decommissioning and restoration costs settled *(Note 25)*	**(34)**	(33)	(37)
Deferred income taxes *(Note 13)*	**90**	80	54
Unrealized (gain) loss from risk management activities	**99**	(175)	(47)
Unrealized foreign exchange (gain) loss	**5**	3	(3)
Provisions	**11**	22	–
Asset impairment charges *(Note 11)*	**324**	17	28
Sundance Units 1 and 2 impairment charge *(Notes 7 and 11)*	**43**	–	–
Reserve on collateral *(Note 6)*	**–**	18	–
Equity loss, net of distributions received *(Note 10)*	**14**	1	2
Other non-cash items	**(12)**	(2)	(1)
	572	809	805
Change in non-cash operating working capital balances *(Note 34)*	**(52)**	(119)	47
Cash flow from operating activities	**520**	690	852
Investing activities			
Additions to property, plant, and equipment *(Notes 21 and 40)*	**(703)**	(453)	(808)
Additions to intangibles *(Notes 23 and 40)*	**(39)**	(30)	(29)
Acquisition of finance lease *(Notes 5 and 9)*	**(312)**	–	–
Proceeds on sale of property, plant, and equipment	**3**	12	6
Proceeds on sale of facilities and development projects *(Note 5)*	**3**	40	–
Acquisition of the remaining 50% of the Taylor Hydro joint venture *(Note 5)*	**–**	(7)	–
Proceeds on sale of minority interest in Kent Hills 2 *(Note 14)*	**–**	–	15
Resolution of certain outstanding tax matters *(Notes 13 and 20)*	**9**	3	29
Realized losses on financial instruments	**(13)**	(12)	(29)
Net increase (decrease) in collateral received from counterparties	**(13)**	(109)	47
Net (increase) decrease in collateral paid to counterparties	**24**	(56)	(2)
Decrease in finance lease receivable *(Note 9)*	**3**	3	2
Other	**(8)**	(3)	6
Change in non-cash investing working capital balances	**(2)**	4	(14)
Cash flow used in investing activities	**(1,048)**	(608)	(777)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 26)*	**152**	155	(400)
Repayment of long-term debt *(Note 26)*	**(314)**	(234)	(10)
Issuance of long-term debt *(Note 26)*	**388**	–	301
Dividends paid on common shares *(Note 28)*	**(104)**	(191)	(216)
Dividends paid on preferred shares *(Note 29)*	**(32)**	(15)	–
Net proceeds on issuance of common shares *(Note 28)*	**293**	2	1
Net proceeds on issuance of preferred shares *(Note 29)*	**217**	267	291
Realized gains (losses) on financial instruments	**(31)**	9	3
Distributions paid to subsidiaries' non-controlling interests *(Note 14)*	**(59)**	(61)	(62)
Other	**(6)**	(2)	–
Cash flow from (used in) financing activities	**504**	(70)	(92)
Cash flow from (used in) operating, investing, and financing activities	**(24)**	12	(17)
Effect of translation on foreign currency cash	**2**	2	(1)
Increase (decrease) in cash and cash equivalents	**(22)**	14	(18)
Cash and cash equivalents, beginning of year	**49**	35	53
Cash and cash equivalents, end of year	**27**	49	35
Cash income taxes paid (recovered)	**30**	(1)	(51)
Cash interest paid	**234**	197	142

See accompanying notes.

notes to consolidated financial statements

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

1. Corporate Information

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 became a subsidiary.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation Segment owns and operates hydro, wind, geothermal, 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

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 Segment 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 Segments.

B. Basis of Preparation

These consolidated financial statements have been prepared by management in compliance with IFRS as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements have been prepared on a historical cost basis except for financial instruments that are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board of Directors on February 26, 2013.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiary so as to obtain benefits from its activities, generally indicated by ownership of, directly or indirectly, more than one-half of the voting rights. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Accounting Policies

A. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be reliably measured.

Revenue from the rendering of services is recognized when criteria ii), iii), and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt hour ("MWh") produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with leases are recognized as outlined in Note 2(R).

Trading activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, 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. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in the Consolidated Statements of Earnings (Loss). The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint ventures each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar while the functional currencies of the subsidiary companies and joint ventures are either the Canadian, U.S., or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rates in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income (Loss) ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income (Loss) ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the net investment as a result of a disposal, partial disposal, or loss of control.

C. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives, and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, 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 nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are removed from the Consolidated Statements of Financial Position when the obligation is discharged, cancelled, or expired.

Derivative instruments that are embedded in financial or non-financial contracts that are not already required to be recognized at fair value are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts and the contract is not measured at fair value. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which is recognized in OCI. Derivatives used in trading activities are described in more detail in Note 2(A).

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. 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.

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 exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific assets and liabilities on the Consolidated Statements of Financial Position or to specific firm commitments or highly probable anticipated transactions.

The Corporation 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. If the above hedge criteria are not met or the Corporation does not apply hedge accounting, the derivative is accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being 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 for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount 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. 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 is achieved if the derivatives' cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If 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 to net earnings from AOCI immediately when it is not probable that the forecasted transaction will occur within the time period specified in the hedge documentation.

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, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair 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 fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. 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 disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts and foreign denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from changes in foreign exchange rates.

D. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

E. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its 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.

F. Inventory

I. Fuel

The Corporation's inventory balance is comprised of coal and natural gas used as fuel, which is measured at the lower of cost and net realizable value. 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 electricity production as maintenance is performed. Due to the limited number 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 and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Trading

Commodity inventories held in the Energy Trading Segment for trading purposes 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.

G. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably.

The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

The estimate of the useful lives of each component 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 component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Thermal generation	3-50 years
Gas generation	2-30 years
Renewable generation	3-60 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction (see Note 2(S)). Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

H. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale of the intangible asset, and its probable future economic benefits, are demonstrated. Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in Depreciation and amortization and Fuel and purchase power in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively. Intangible assets with indefinite useful lives are not amortized, but are tested for impairment annually.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, coal rights, software, and intangibles under development. Estimated useful lives of intangible assets are as follows:

Software	2-7 years
Power contracts	1-30 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period the Corporation reviews the net carrying amount of PP&E and finite life intangible assets to determine whether there is any indication that an impairment loss may exist.

Factors that could indicate an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating a possible impairment does not occur. Instead, a series of individually insignificant events occurs over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's businesses, the market, and the business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. When the recoverable amount is based on value in use, the Corporation bases its impairment on detailed cash flow budgets and forecasts over the asset's useful life. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

J. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but 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 CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs to which the goodwill relates is compared to the carrying amount of the CGUs. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

K. Project Development Costs

Project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as 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 costs incurred subsequently are included in other assets. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

M. Employee Future Benefits

The Corporation accrues its obligations under employee future benefit plans and the related costs, net of plan assets. The cost of pension and other post-employment benefits, such as health and dental benefits, earned by employees is actuarially determined using the projected unit credit 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 a weighted average of the expected future capital market returns, at the beginning of the period, for categories of investments aligned with the mix of plan assets, determined based on the plan's investment policy, for returns over the life of the benefit obligations. The discount rate used to determine the present value of the defined benefit obligation is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations.

Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. The Corporation determines an estimate of the actuarial gains or losses incurred in each reporting period using updated fair values for plan assets and period-end discount rates for computing the defined benefit obligation. Resulting changes in actuarial gains or losses are recognized in OCI in the reporting period in which they occur. Past service costs are recognized immediately in net earnings to the extent that the benefits have vested; otherwise, they are amortized on a straight-line basis over the vesting period.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Corporation's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Corporation as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

N. Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation may arise from the Corporation's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the Corporation has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, re-measured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. At each reporting date, the Corporation determines the present value of the provision using current discount rates that reflect the time value of money and associated risks. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(G)). The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. Where the Corporation expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received. Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

O. Share-Based Payments

The Corporation measures equity-settled stock option awards using the fair value method. Compensation expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled share-based payment award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation costs associated with awards under the Performance Share Ownership Plan ("PSOP") are accrued based on the fair value of each award, the service period completed, and the number of equivalent common shares eligible employees and directors have earned each period-end, which is 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 comparative group.

For share-based payments earned under cash-settled phantom stock option plans, a liability, and corresponding compensation cost, is recognized at each period-end, until final settlement, based on the fair value of each award and the service period completed.

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its 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.

Emission credits and allowances that are held for trading and 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.

Q. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Any impairment is recognized in net earnings. Depreciation ceases when an asset is classified as held for sale. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position.

R. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (i.e. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a "Finance Lease Receivable". The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant periodic rate of return on the net investment in each period and is reflected in "Finance Lease Income" on the Consolidated Statements of Earnings (Loss).

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life. Rental income, including contingent rent, from operating leases, is recognized over the term of the arrangement and is reflected in "Revenue" on the Consolidated Statements of Earnings (Loss). Contingent rent may arise when payments due under the contract are not fixed in amount but vary based on a future factor such as the amount of use or production.

S. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

T. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used.

Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains controls.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

U. Joint Ventures

A joint venture is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. TransAlta's joint ventures are generally classified as two types: jointly controlled assets and jointly controlled entities.

A jointly controlled asset arises when the joint venturers have joint control or joint ownership of one or more assets contributed to, or acquired for and dedicated to, the purpose of the joint venture. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint venture. The Corporation reports its interests in jointly controlled assets in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues, and expenses in respect of its interest in the joint venture.

In jointly controlled entities, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer is entitled to a share of the net earnings of the jointly controlled entity. The Corporation reports its interests in jointly controlled entities using the equity method or the proportionate consolidation method, as considered appropriate on an investment by investment basis. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the jointly controlled entity's net earnings or loss after the date of acquisition. The impact of transactions between the Corporation and jointly controlled entities are eliminated based on the Corporation's ownership interest. Distributions received from jointly controlled entities reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities, and contingent liabilities of an acquired jointly controlled entity is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in jointly controlled entities are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. Objective evidence could include, for example, such factors as significant financial difficulty of the investee, or information about significant changes with an adverse effect that have taken place in the technological, market, economic, or legal environment in which the investee operates, which may indicate that the cost of the investment may not be recovered. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs to sell.

V. Government Grants

Government grants are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the grant and that the grant will be received. When the grant relates to an expense item, it is recognized in net earnings over the same period in which the related costs or revenues are recognized. When the grant relates to an asset, it is recognized as a reduction of the carrying amount of PP&E and released to earnings as a reduction in depreciation over the expected useful life of the related asset.

W. Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of consolidated financial statements requires management to make judgments, estimates, and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses, and disclosures of contingent assets and liabilities 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, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation, and regulations.

In the process of applying the Corporation's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the consolidated financial statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset or CGU to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less cost to sell and its value in use. In determining fair value less costs to sell, information about third-party transactions for similar assets is used and if none are available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs to sell or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs, and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management uses 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, changes to regulations, and transmission capacity or constraints for the remaining life of the plant. These estimates and assumptions are susceptible to change from period to period and 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. Key assumptions used in determining the recoverable amount of the Centralia Coal plant and Sundance Units 1 and 2 are further explained in Note 11.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense, is dependent upon such classifications.

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation, to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amount recognized for deferred income tax assets and liabilities.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 16. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value. The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility, and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 25. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VII. Useful Life of PP&E

Each significant component of an item of 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, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

VIII. Employee Future Benefits

The Corporation provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets;
- the effects of changes to the provisions of the plans; and
- changes in key actuarial assumptions, including anticipated rates of return on plan assets, rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate.

IX. Other Provisions

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

3. Accounting Changes

A. Current Year Accounting Changes

Change in Estimates – Useful Lives

As a result of amendments to Canadian federal regulations requiring that coal-fired plants be shutdown after 50 years of operation, the Corporation has reviewed the useful lives of its Alberta coal-fired generating facilities and related coal mining assets and where permitted under the regulations, extended the useful lives to a maximum of 50 years. The previous draft regulations proposed shutdown after 45 years. As a result, depreciation expense was reduced by $12 million for the year ended Dec. 31, 2012 compared to 2011, and is expected to be reduced by $23 million annually thereafter.

B. Prior Year Accounting Changes

I. IFRS

On Jan. 1, 2011, the Corporation adopted IFRS for publicly accountable enterprises. For information on the impact of the transition to IFRS refer to Note 3 of the Corporation's Dec. 31, 2011 annual consolidated financial statements.

II. Change in Estimates – Residual Values

During the first quarter of 2011, management completed a comprehensive review of the residual values of all of TransAlta's generating assets, having regard for, among other things, expectations about the future condition of the assets, metal volumes, as well as other market-related factors. As a result, estimated residual values were revised, resulting in depreciation decreasing by $13 million for the year ended Dec. 31, 2011 compared to 2010.

C. Comparative Figures

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

D. Future Accounting Changes

I. Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements* ("IFRS 10"), which replaces International Accounting Standard 27 *Consolidated and Separate Financial Statements* ("IAS 27") and Standing Interpretations Committee Interpretation 12 *Consolidation – Special Purpose Entities* ("SIC-12"). IFRS 10 provides a revised definition of control so that a single control model can be applied to all entities for consolidation purposes.

II. Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements*, which supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principle-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its joint arrangements. There are two types of joint arrangements under IFRS 11: joint operations and joint ventures. IFRS 11 requires the use of the equity method of accounting for interests in joint ventures, whereas for joint operations, each party recognizes its respective share of the assets, liabilities, revenues and expenses.

III. Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in consolidated and unconsolidated entities, such as subsidiaries, joint arrangements, associates, and unconsolidated structured entities (special purpose entities).

IV. Investments in Associates and Joint Ventures and Separate Financial Statements

In May 2011, two existing standards, IAS 28 *Investments in Associates and Joint Ventures* and IAS 27 *Separate Financial Statement*s, were amended. The amendments are not significant, and result from the issuance of IFRS 10, IFRS 11, and IFRS 12.

V. Amendments to IFRS 10, IFRS 11, and IFRS 12

In June 2012, the IASB issued *Consolidated Financial Statements, Joint Arrangements and Disclosure of Interests in Other Entities: Transition Guidance* (Amendments to IFRS 10, IFRS 11, and IFRS 12). The amendments clarify the transition guidance in IFRS 10 and provide additional transition relief for all three standards by limiting the requirement to provide adjusted comparative information to only the preceding comparative period.

The requirements of the preceding new standards and amendments to existing standards outlined in a. through e. are effective for the Corporation on Jan. 1, 2013. The adoption is not expected to have a material financial impact upon the consolidated financial position or results of operations; however, new or enhanced disclosures will be required for the Corporation's March 31, 2013 interim reporting period, primarily as a result of the adoption of IFRS 12.

VI. Fair Value Measurement

In June 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for all fair value measurements required by other IFRS; clarifies the definition of fair value; and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability, or its own equity instrument at fair value. IFRS 13 is effective for the Corporation on Jan. 1, 2013. The adoption is not expected to have a material financial impact upon the consolidated financial position or results of operations; however, new or enhanced disclosures will be required for the Corporation's March 31, 2013 interim reporting period, primarily related to Level III fair values.

VII. Presentation of Financial Statements

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The amendments to IAS 1 are effective for the Corporation on Jan. 1, 2013, at which time the items presented within the Consolidated Statements of Comprehensive Income (Loss) will be reorganized to comply with the required groupings.

VIII. Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits* to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service and net interest costs are presented in net earnings and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI. The net interest cost introduced in these amendments removes the concept of expected return on plan assets that was previously recognized in net earnings. The amendments eliminate the option to defer the recognition of actuarial gains and losses, known as the 'corridor method'. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for the Corporation on Jan. 1, 2013 and must be applied retrospectively. On adoption, the Corporation expects to reclassify an approximate $12 million after-tax charge from AOCI to retained earnings (deficit), which represents the increase in prior periods' pension expense as a result of the application of the net interest cost requirements. The elimination of the corridor method will have no impact as the Corporation has, since adoption of IFRS, recognized actuarial gains and losses in OCI in the period in which they occurred.

IX. Financial Instruments

In November 2009, the IASB issued IFRS 9 *Financial Instruments,* which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or at fair value through profit or loss or through OCI depending on the basis of the entity's business model for managing the financial asset, and the contractual cash flow characteristics of the financial asset.

In October 2010, the IASB issued additions to IFRS 9 regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

In December 2011, the IASB amended the effective date of these requirements, which are now effective for annual periods beginning on or after Jan. 1, 2015, and must be applied on a modified retrospective basis. Earlier adoption is permitted. The December amendment also provided relief from restating comparative periods and from the associated disclosures required under IFRS 7 *Financial Instruments: Disclosures*.

The Corporation does not expect that any material impacts will result from these standards, however, continues to assess the impact of adopting these amendments on the consolidated financial statements.

X. Stripping Costs in the Production Phase of a Surface Mine

In October 2011, the IFRS Interpretations Committee issued Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine* ("IFRIC 20"), which clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods. The Interpretation is effective for the Corporation on Jan. 1, 2013 and must be applied by the Corporation to production stripping costs incurred on and after Jan 1, 2011. On adoption, the Corporation expects to recognize approximately $9 million in costs as a stripping activity asset.

XI. Offsetting Financial Assets and Liabilities

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation*. The amendments are intended to clarify certain aspects of the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements on offsetting. The IASB also amended IFRS 7 to require disclosures about all recognized financial instruments that are set off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set off under IAS 32.

The amendments to IAS 32 are effective for annual periods beginning on or after Jan. 1, 2014. The Corporation is currently assessing the impact of adopting the IAS 32 amendments on the consolidated financial statements. The new offsetting disclosures are required for annual or interim periods beginning on or after Jan. 1, 2013, and are expected to be included in the Corporation's March 31, 2013 interim reporting period. The amendments need to be provided retrospectively to all comparative periods.

XII. Annual Improvements 2009-2011

In May 2012, the IASB issued a collection of necessary, non-urgent amendments to several IFRS resulting from its annual improvements process. The amendments are effective for the Corporation's 2013 annual period. None of the narrow-scope amendments are expected to have a material financial impact upon the consolidated financial position or results of operations.

XIII. Investment Entities (Amendments to IFRS 10 and 11 and IAS 27)

In October 2012, the IASB issued *Investment Entities* (Amendments to IFRS 10 and 11 and IAS 27). The amendments provide an exception to the consolidation requirements in IFRS 10 and require investment entities to measure particular subsidiaries at fair value through profit or loss, rather than consolidate them. An investment entity is an entity whose business purpose is to invest funds solely for returns from capital appreciation, investment income, or both. The amendments are effective retrospectively from Jan. 1, 2014, with early adoption permitted, and are not expected to have a material financial impact upon the consolidated financial position or results of operations.

4. Restructuring Charges

On Oct. 30, 2012, the Corporation announced a restructuring of resources as part of its ongoing strategy to continuously improve operational excellence and accelerate the growth of the company. The restructure is expected to result in a net reduction of approximately 165 positions within a six-month period. As a result of the restructuring, a provision and related pre-tax restructuring expense of $13 million was recognized. Please see Note 25 for a reconciliation of changes in the provision.

5. Acquisitions and Disposals

A. Acquisitions

On Sept. 28, 2012, the Corporation acquired the 125 megawatt ("MW") Solomon power station located in Western Australia from Fortescue Metals Group Ltd. ("Fortescue") for U.S.$318 million. The power station is currently under construction and is expected to be commissioned during the first half of 2013. The facility is fully contracted with Fortescue under a long-term Power Purchase Agreement ("Agreement") with an initial term of 16 years that commenced in October 2012, after which Fortescue will have the option to either extend the Agreement for an additional five years under the same terms, or to acquire the facility. The Corporation has accounted for the facility and associated Agreement as a finance lease with TransAlta being the lessor (see Note 9).

On Nov. 1, 2011, the Corporation purchased the remaining 50 per cent of the Taylor Hydro jointly controlled asset from Capital Power, the joint venture partner, for $7 million. As the Corporation acquired control of the overall business, the entire asset was remeasured at the acquisition-date fair value.

B. Disposals

During 2011, the Corporation sold its biomass facility located in Grande Prairie. The sale was effective Sept. 1, 2011 and closed on Oct. 1, 2011. As a result, the Corporation realized a pre-tax gain of $9 million. During 2012, the Corporation realized a pre-tax gain of $3 million resulting from the release of the remaining consideration related to the achievement of the Environmental Attribute Conditions by the purchaser.

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. The sale was effective Jan. 1, 2011 and closed in April 2011, and resulted in the recognition of a pre-tax gain of $3 million in 2011.

6. Gain on Sale of (Reserve on) Collateral

During September 2012, the Corporation sold, for net proceeds of U.S.$33 million, its claim against MF Global Inc. pertaining to the return of U.S.$36 million of collateral that had been posted by the Corporation. As a result, a pre-tax gain of $15 million ($11 million after tax) was realized. The claim, filed during the first quarter of 2012, related primarily to the Corporation's collateral on foreign futures transactions.

In October 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which was used by TransAlta as a broker-dealer for certain commodity transactions. MF Global Inc. had not filed for bankruptcy in 2011 but, under the U.S. *Securities Investor Protection Act*, the Securities Investor Protection Corp. was overseeing a liquidation of the broker-dealer to return assets to customers. A trustee had been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of TransAlta's collateral related to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and was subject to a dispute between the U.S. trustee and the U.K. administrator. In December 2011, TransAlta had net collateral of approximately U.S.$36 million with MF Global Inc. and due to the uncertainty of collection, a U.S.$18 million reserve was recognized. At Dec. 31, 2011, the net amount of the collateral had been reclassified to a long-term asset on the Consolidated Statements of Financial Position.

7. Sundance Units 1 and 2 Arbitration

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of the Corporation's Sundance facility were shutdown due to conditions observed in the boilers at both units. On Feb. 8, 2011, the Corporation issued a notice of termination for destruction based on the determination that the units could not be economically restored to service under the terms of the PPA. Due to the uncertainty of the results of the arbitration ruling, the Corporation had been continuing to accrue the capacity payments, net of a provision, and to depreciate the assets.

The matter was heard before an arbitration panel during the second quarter of 2012. On July 20, 2012, the arbitration panel concluded that Unit 1 and Unit 2 were not economically destroyed and the Corporation will restore the units to service. The panel has affirmed that the event meets the criteria of force majeure beginning on Nov. 20, 2011 until such time that the units are returned to service. During the force majeure period, the Corporation continues to be entitled to capacity payments.

The pre-tax income statement impact of the ruling that has been recorded under Sundance Units 1 and 2 arbitration in the Consolidated Statements of Earnings (Loss) during the year ended Dec. 31, 2012 is as follows:

	2012
Availability incentive penalties	260
Reversal of provision on capacity payments	(64)
Impairment of the units *(Note 11)*	43
Interest	9
Legal and other costs	6
Total pre-tax impact[1]	**254**

1 *Related income tax recovery for the year ended Dec.31, 2012, is $65 million.*

8. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2012		2011		2010	
	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration
Fuel	649	–	721	–	891	–
Purchased power	115	–	183	–	253	–
Salaries and benefits	4	255	3	289	4	276
Depreciation	41	–	40	–	37	–
Other operating expenses	–	238	–	256	–	234
Total	**809**	**493**	947	545	1,185	510

9. Leases

A. The Corporation as Lessor

I. Finance Leases

Amounts receivable under the Corporation's finance leases, including the Fort Saskatchewan cogeneration facility and the Solomon power station finance leases, are as follows:

As at Dec. 31	2012		2011	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	46	43	10	9
Second to fifth years inclusive	194	132	41	25
More than five years	513	158	31	11
	753	333	82	45
Less: unearned finance lease income	558	–	37	–
Add: unguaranteed residual value	164	26	–	–
Total finance leases receivable	**359**	**359**	45	45
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease receivable	2		3	
Non-current finance lease receivable	357		42	
	359		45	

The interest rates inherent in the leases are fixed at the contract date for the entire lease term and are approximately 17 per cent (2011 – 17 per cent) and 12 per cent per annum (2011 – nil), respectively, for the Fort Saskatchewan and the Solomon finance leases.

II. Operating Leases

Several of the Corporation's PPAs and other long-term contracts meet the criteria of operating leases. Total rental income, including contingent rent, related to these contracts and reported in revenues in the Consolidated Statements of Earnings (Loss) for the year ended Dec. 31, 2012 was $188 million (2011 - $159 million, 2010 - $205 million).

B. The Corporation as Lessee

I. Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment.

During the year ended Dec. 31, 2012, $13 million (2011 – $12 million, 2010 – $12 million) was recognized as an expense in the Consolidated Statements of Earnings (Loss) in respect of these operating leases. No sublease payments were received or made, nor were any contingent rental payments made, in respect of these operating leases.

Future minimum lease payments required under non-cancellable operating leases are as follows:

2013	10
2014	8
2015	8
2016	7
2017	7
2018 and thereafter	28
Total minimum lease payments	**68**

10. Investments

The Corporation's investment in jointly controlled entities, accounted for using the equity method, consists of its investments in CE Gen and Wailuku.

The change in investments is as follows:

Balance, Dec. 31, 2010	190
Equity income	14
Distributions received	(15)
Change in foreign exchange rates	4
Balance, Dec. 31, 2011	193
Equity loss	(15)
Distributions received	(1)
Change in foreign exchange rates	(5)
Balance, Dec. 31, 2012	**172**

Summarized information on the results of operations and financial position relating to the Corporation's pro-rata interests in CE Gen and Wailuku is as follows:

Year ended Dec. 31	2012	2011	2010
Results of operations			
Revenues	**101**	133	136
Expenses	**(116)**	(119)	(129)
Proportionate share of net earnings (loss)	**(15)**	14	7

As at Dec. 31	2012	2011
Financial position		
Current assets	**29**	42
Long-term assets	**385**	423
Current liabilities	**(31)**	(29)
Long-term liabilities	**(197)**	(229)
Non-controlling interests	**(14)**	(14)
Proportionate share of net assets	**172**	193

11. Asset Impairment Charges

A. Sundance Units 1 and 2

During 2012, the Corporation recognized a net impairment loss of $2 million on Sundance Units 1 and 2. The net loss is comprised of a $43 million impairment loss taken in the second quarter and a $41 million reversal in the third quarter. The second quarter impairment loss resulted from the conclusion of the Sundance Units 1 and 2 arbitration and was based on an estimate of fair value less costs to sell, derived from the cash flows expected to result under the provisions of the PPA (see Note 7). The reversal arose as a result of the additional years of merchant operations expected to be realized at Units 1 and 2 due to the recent amendments to Canadian federal regulations requiring that coal-fired plants be shutdown after a maximum of 50 years of operation. The previous draft regulations proposed shutdown after 45 years. The recoverable amount was based on an estimate of fair value less costs to sell, derived from the cash flows expected to result over the revised useful life of the units, taking into consideration the provisions of the PPA and prices evidenced in the marketplace.

During 2010, the Corporation recorded a pre-tax impairment charge of $21 million related to Units 1 and 2 at the Sundance facility resulting from the December 2010 shutdown due to the physical state of the boilers and the determination, at that time, that the units could not be economically restored to service under the terms of the PPA.

The losses and reversal are included in the Generation Segment.

B. Centralia Thermal

In 2011, the TransAlta Energy Bill (the "Bill") was signed into law in the State of Washington. The Bill, and a Memorandum of Agreement (the "MoA") signed on Dec. 23, 2011, which is part of the Bill, provide a framework to transition from coal-fired energy produced at the Corporation's Centralia Thermal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of the shutdown of the units and the removal of restrictions on the terms of power contracts that the Corporation can enter into.

On July 25, 2012, the Corporation announced that a long-term power agreement was signed for supply of power from December 2014 until the facility is fully retired in 2025. The agreement was approved, with conditions, by the Washington Utilities and Transportation Commission ("WUTC") on Jan. 10, 2013. On Jan. 23, 2013, it was announced that Puget Sound Energy has filed a petition for reconsideration of certain conditions within the decision issued by the WUTC. On Feb. 5, 2013, the WUTC granted a 30-day extension to the petition and indicated that it would issue its decision on the petition no later than March 29, 2013.

In the second quarter of 2012, the Corporation completed an assessment of whether the carrying amount of the Centralia Thermal plant is recoverable based on an estimate of fair value less costs to sell. As a result, a pre-tax impairment charge of $347 million was recognized and included in the Generation Segment. The fair value was determined based on the future cash flows expected to be derived from the plant's operations, determined by prices evidenced in the agreement and Mid-Columbia forward market prices. In addition to the assumptions regarding the long-term power agreement, the significant assumptions used in estimating the fair value and arriving at the resulting impairment of the Centralia Thermal plant were as follows: the choice of the appropriate discount rate based on a weighted-average cost of capital, incorporating market returns, risks specific to the asset, and a hypothetical capital structure based on the capital structure of companies with a similar asset and risk profiles; determinations regarding the amount of electricity sold, the timing of such sales, and related pricing, under additional contracts the Corporation may be able to secure for sale of output from the plant; forecasts of future market prices beyond the period for which third-party forecasts are available, which impact revenues from uncontracted production; and forecasts of coal and related delivery costs beyond the period for which the plant's fuel supply is currently contracted.

In addition to the impairment charge, $169 million of deferred income tax assets were written off as it is no longer probable that sufficient taxable income will be available from the Corporation's U.S. operations, which have been impacted by the Centralia Thermal plant impairment, to allow the benefit associated with the deferred income tax assets to be utilized.

C. Renewables

During 2012, the Corporation recognized a pre-tax impairment charge of $18 million related to five assets within the renewables fleet. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs to sell, derived from long-range forecasts and prices evidenced in the marketplace. The assets were impaired primarily due to expectations regarding lower market prices. The impairment losses are included in the Generation Segment.

During 2011, the Corporation recorded a pre-tax impairment charge of $17 million related to four Generation assets within the renewables fleet in order to write the assets down to their estimated fair values less cost to sell. The fair value estimates for assets were derived from the long-range forecasts and prices were evidenced in the marketplace. Two of the assets were impaired due to operational factors that impacted their useful lives, resulting in an impairment charge of $5 million. The impairment charges on the other two assets, totalling $12 million, resulted from the Corporation's annual comprehensive impairment assessment and reflect lower forecast pricing at these merchant facilities.

D. Gas

During 2010, the Corporation recorded a pre-tax impairment charge of $7 million (nil after deducting the amount that is attributed to the non-controlling interest) on the Meridian facility, as a result of the sale of the Corporation's 50 per cent interest in the facility.

E. Reversals

Impairment charges and the reduction of the deferred income tax assets can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants, and the estimated taxable income to be generated by the Corporation's U.S. operations, respectively, improve.

12. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2012	2011	2010
Interest on debt	**227**	228	226
Interest income	**(2)**	–	(18)
Capitalized interest *(Note 21)*	**(4)**	(31)	(48)
Ineffectiveness on hedges	**4**	(1)	–
Interest expense	**225**	196	160
Accretion of provisions *(Note 25)*	**17**	19	18
Net interest expense	**242**	215	178

The Corporation capitalizes interest during the construction phase of growth capital projects. In 2012, $4 million was capitalized related to New Richmond. The capitalized interest in 2011 relates primarily to Keephills Unit 3. Capitalized interest in 2010 relates primarily to Keephills Unit 3, Ardenville, and the Kent Hills expansion.

13. Income Taxes

A. Consolidated Statements of Earnings (Loss)

I. Rate Reconciliations

Year ended Dec. 31	2012	2011	2010
Earnings (loss) before income taxes	**(443)**	449	304
Equity (income) loss *(Note 10)*	**15**	(14)	(7)
Net earnings attributable to non-controlling interests	**(37)**	(38)	(24)
Adjusted earnings (loss) before income taxes	**(465)**	397	273
Statutory Canadian federal and provincial income tax rate (%)	**25.0**	26.5	28.0
Expected income tax expense (recovery)	**(116)**	105	76
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(49)**	(3)	(15)
Resolution of uncertain tax matters	**(27)**	–	(30)
Statutory and other rate differences	**7**	(1)	(10)
Writedown of deferred income tax assets	**289**	–	–
Other	**(1)**	5	3
Income tax expense	**103**	106	24
Effective tax rate *(%)*	**(22)**	27	9

II. Components of Income Tax Expense

The components of income tax expense (recovery) are as follows:

Year ended Dec. 31	2012	2011	2010
Current income tax expense	**27**	26	–
Adjustments in respect of current income tax of previous years	**(3)**	–	(30)
Adjustments in respect of deferred income tax of previous years	**1**	–	–
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(70)**	78	53
Deferred income tax expense resulting from changes in tax rates or laws[1]	**7**	–	–
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce current income tax expense	**(11)**	–	–
(Benefit) expense arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**(16)**	2	–
Deferred income tax expense arising from the writedown of deferred income tax assets	**168**	–	1
Income tax expense	**103**	106	24

1 *Related to the impact of the June 20, 2012 Ontario budget bill, which freezes the Ontario general corporate tax rate at 11.5%. The Corporation had been using the previously substantively enacted tax rate of 10.0%.*

Year ended Dec. 31	2012	2011	2010
Current income tax expense (recovery)[2]	**13**	26	(30)
Deferred income tax expense	**90**	80	54
Income tax expense	**103**	106	24

2 *During 2010, TransAlta recognized and received a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense in 2010 was reduced by $14 million as a result of tax-related interest recoveries.*

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2012	2011	2010
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(15)**	(101)	25
Net impact related to net investment hedges	**4**	(5)	6
Net actuarial losses	**(10)**	(9)	(7)
Common and preferred share issuance costs	**(5)**	(2)	(2)
Income tax expense (recovery) reported in equity	**(26)**	(117)	22

C. Consolidated Statements of Financial Position

Significant components of the Corporation's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2012	2011
Net operating and capital loss carryforwards[3]	**405**	453
Future decommissioning and restoration costs	**91**	99
Property, plant, and equipment[3]	**(987)**	(912)
Risk management assets and liabilities, net	**(21)**	(72)
Employee future benefits and compensation plans	**67**	59
Allowance for doubtful accounts	**18**	19
Other deductible temporary differences	**47**	39
Net deferred income tax liability	**(380)**	(315)

3 *During 2012, the Corporation wrote off $289 million of deferred income tax assets related to net operating losses and property, plant, and equipment of its U.S. operations. The net operating losses expire between 2022 and 2032.*

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2012	2011
Deferred income tax assets	**50**	169
Deferred income tax liabilities	**(430)**	(484)
Net deferred income tax liability	**(380)**	(315)

The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2012, the Corporation had recognized a net liability of $9 million (2011 – $43 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

Balance, Dec. 31, 2010	(44)
Increase as a result of tax positions taken during a prior period	(5)
Decrease as a result of settlements with taxation authorities	6
Balance, Dec. 31, 2011	(43)
Decrease as a result of settlements with taxation authorities	34
Balance, Dec. 31, 2012	**(9)**

14. Non-Controlling Interests

A. Consolidated Statements of Earnings (Loss)

Year ended Dec. 31	2012	2011	2010
Stanley Power's interest (49.99%) in TransAlta Cogeneration, L.P.	**34**	35	23
Natural Forces Technologies Inc.'s interest (17%) in Kent Hills	**3**	3	1
Total	**37**	38	24

B. Consolidated Statements of Financial Position

As at Dec. 31	2012	2011
Stanley Power's interest in TransAlta Cogeneration, L.P.	**290**	317
Natural Forces Technologies Inc.'s interest in Kent Hills	**40**	41
Total	**330**	358

The change in non-controlling interests is as follows:

Balance, Dec. 31, 2010	431
Distributions paid[1]	(91)
Non-controlling interests portion of net earnings	38
Non-controlling interests portion of OCI	(20)
Balance, Dec. 31, 2011	358
Distributions paid	(59)
Non-controlling interests portion of net earnings	37
Non-controlling interests portion of OCI	(6)
As at Dec. 31, 2012	**330**

1 *Includes a $30 million non-cash distribution related to the sale of the Meridian facility.*

C. Consolidated Statements of Cash Flows

Distributions paid by subsidiaries to non-controlling interests are as follows:

Year ended Dec. 31	2012	2011	2010
TransAlta Cogeneration, L.P.	55	57	60
Kent Hills	4	4	2
Total	59	61	62

15. Accounts Receivable

As at Dec. 31	2012	2011
Gross accounts receivable	643	588
Allowance for doubtful accounts *(Note 36)*	(46)	(47)
Net accounts receivable	597	541

The change in allowance for doubtful accounts is as follows:

Balance, Dec. 31, 2010	46
Change in foreign exchange rates	1
Balance, Dec. 31, 2011	47
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2012	46

16. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at fair value or amortized cost (see Note 2(C)). The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Dec. 31, 2012

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Accounts receivable	–	–	597	–	597
Collateral paid	–	–	19	–	19
Finance lease receivable[1]	–	–	359	–	359
Risk management assets					
Current	14	187	–	–	201
Long-term	18	51	–	–	69
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	495	495
Collateral received	–	–	–	2	2
Dividends payable	–	–	–	75	75
Risk management liabilities					
Current	47	120	–	–	167
Long-term	95	11	–	–	106
Long-term debt[1]	–	–	–	4,217	4,217

1 *Includes current portion.*

Carrying value of financial instruments as at Dec. 31, 2011

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Accounts receivable	–	–	541	–	541
Collateral paid	–	–	45	–	45
Finance lease receivable[1]	–	–	45	–	45
Risk management assets					
Current	10	381	–	–	391
Long-term	35	64	–	–	99
Long-term receivable	–	–	18	–	18
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	463	463
Collateral received	–	–	–	16	16
Dividends payable	–	–	–	67	67
Risk management liabilities					
Current	71	137	–	–	208
Long-term	128	14	–	–	142
Long-term debt[1]	–	–	–	4,037	4,037

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. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes, in Level II, over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs 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.

c. *Level III*

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

The Corporation may enter into commodity transactions 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.

TransAlta also has various contracts with terms that extend beyond a liquid trading period. 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.

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 years ended Dec. 31, 2012 and 2011, respectively:

	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, 2011	–	(90)	(14)	–	287	7	–	197	(7)
Changes attributable to:									
Market price changes on existing contracts	–	25	10	–	(3)	27	–	22	37
Market price changes on new contracts	–	7	–	–	(10)	4	–	(3)	4
Contracts settled	–	14	7	(1)	(210)	(14)	(1)	(196)	(7)
Discontinued hedge accounting on certain contracts	–	(19)	–	–	15	4	–	(4)	4
Net risk management assets (liabilities) at Dec. 31, 2012	**–**	**(63)**	**3**	**(1)**	**79**	**28**	**(1)**	**16**	**31**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			17			–			17
Realized gain (loss) included in earnings before income taxes			(7)			14			7
Unrealized gain included in earnings before income taxes relating to net assets held at Dec. 31, 2012			–			31			31

	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, 2010	–	319	(20)	(1)	53	–	(1)	372	(20)
Changes attributable to:									
Market price changes on existing contracts	–	(66)	(19)	(13)	47	31	(13)	(19)	12
Market price changes on new contracts	–	13	–	13	66	2	13	79	2
Contracts settled	–	(187)	(1)	1	(48)	–	1	(235)	(1)
Discontinued hedge accounting on certain contracts	–	(169)	26	–	169	(26)	–	–	–
Net risk management assets (liabilities) at Dec. 31, 2011	–	(90)	(14)	–	287	7	–	197	(7)
Additional Level III gain (loss) information:									
Change in fair value included in OCI			(20)			–			(20)
Realized gain included in earnings before income taxes			1			–			1
Unrealized gain included in earnings before income taxes relating to net assets held at Dec. 31, 2011			–			33			33

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at Dec. 31, 2012 is estimated to be +/- $26 million (Dec. 31, 2011 - $33 million). Fair values are stressed for volumes and prices. The volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

The anticipated settlement of the contracts outstanding at Dec. 31, 2012, over each of the next five calendar years and thereafter, is as follows:

		2013	2014	2015	2016	2017	2018 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	(9)	(14)	(15)	(17)	(9)	1	(63)
	Level III	–	–	–	1	–	2	3
Non-Hedges	Level I	(1)	–	–	–	–	–	(1)
	Level II	44	28	3	3	1	–	79
	Level III	15	11	6	5	1	(10)	28
Total	Level I	(1)	–	–	–	–	–	(1)
	Level II	35	14	(12)	(14)	(8)	1	16
	Level III	15	11	6	6	1	(8)	31
Total net assets (liabilities)		**49**	**25**	**(6)**	**(8)**	**(7)**	**(7)**	**46**

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 foreign operations, and similar non-hedge transactions.

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the years ended Dec. 31, 2012 and 2011, respectively:

	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, 2011	–	(50)	–	–	–	–	–	(50)	–
Changes attributable to:									
Market price changes on existing contracts	–	(17)	–	–	–	–	–	(17)	–
New contracts	–	(7)	–	–	1	–	–	(6)	–
Contracts settled	–	24	–	–	–	–	–	24	–
Net risk management assets (liabilities) at Dec. 31, 2012	**–**	**(50)**	**–**	**–**	**1**	**–**	**–**	**(49)**	**–**

	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, 2010	–	(37)	–	–	1	–	–	(36)	–
Changes attributable to:									
Market price changes on existing contracts	–	25	–	–	–	–	–	25	–
New contracts	–	(34)	–	–	(1)	–	–	(35)	–
Contracts settled	–	(4)	–	–	–	–	–	(4)	–
Net risk management liabilities at Dec. 31, 2011	–	(50)	–	–	–	–	–	(50)	–

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.

The anticipated settlement of the contracts outstanding at Dec. 31, 2012, over each of the next five calendar years and thereafter, is as follows:

		2013	2014	2015	2016	2017	2018 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	(24)	(3)	(30)	(2)	(1)	10	(50)
	Level III	–	–	–	–	–	–	–
Non-Hedges	Level I	–	–	–	–	–	–	–
	Level II	1	–	–	–	–	–	1
	Level III	–	–	–	–	–	–	–
Total	Level I	–	–	–	–	–	–	–
	Level II	(23)	(3)	(30)	(2)	(1)	10	(49)
	Level III	–	–	–	–	–	–	–
Total net assets (liabilities)		**(23)**	**(3)**	**(30)**	**(2)**	**(1)**	**10**	**(49)**

The fair value of financial liabilities measured at other than fair value is as follows:

	Fair value[1]				Total
	Level I	Level II	Level III	Total	carrying value
Long-term debt – Dec. 31, 2012[2]	**–**	**4,426**	**–**	**4,426**	**4,217**
Long-term debt – Dec. 31, 2011[2]	–	4,324	–	4,324	4,037

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, finance lease receivable, long-term receivable, 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 based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are 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 Statements of Financial Position 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 fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes during the year is as follows:

Year ended Dec. 31	**2012**	2011
Unamortized gain at beginning of year	**4**	1
New inception gains	**3**	8
Amortization recorded in net earnings during the year	**(2)**	(5)
Unamortized gain at end of year	**5**	4

17. Risk Management Activities

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at Dec. 31	2012					2011
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	–	12	–	186	198	390
Long-term	–	8	–	51	59	73
Total energy trading risk management assets	–	20	–	237	257	463
Other						
Current	1	1	–	1	3	1
Long-term	–	–	10	–	10	26
Total other risk management assets	1	1	10	1	13	27
Risk management liabilities						
Energy trading						
Current	–	21	–	120	141	167
Long-term	–	59	–	11	70	106
Total energy trading risk management liabilities	–	80	–	131	211	273
Other						
Current	–	26	–	–	26	41
Long-term	–	36	–	–	36	36
Total other risk management liabilities	–	62	–	–	62	77
Net energy trading risk management assets (liabilities)	–	(60)	–	106	46	190
Net other risk management assets (liabilities)	1	(61)	10	1	(49)	(50)
Net total risk management assets (liabilities)	1	(121)	10	107	(3)	140

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

The Corporation hedges its net investment in foreign operations with U.S. denominated borrowings, cross-currency interest rate swaps, and foreign currency forward contracts.

The Corporation's net investment hedges are comprised of U.S. dollar denominated long-term debt with a face value of U.S.$770 million (Dec. 31, 2011 – U.S.$820 million) and the following foreign currency forward contracts:

As at Dec. 31	2012			2011			
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Currency Forward Contracts							
AUD175	CAD181	1	2013	AUD185	CAD184	(4)	2012
USD35	CAD34	–	2013	USD135	CAD138	–	2012

During 2012, the Corporation de-designated $300 million of borrowings under a U.S. dollar denominated credit facility, $50 million of U.S. dollar denominated senior notes, and U.S.$60 million of foreign currency forward contracts from its net investment hedges due to a reduction in its investment in U.S. foreign operations arising from the Centralia Thermal plant impairment. The cumulative net foreign exchange gains (losses) related to these hedges up to the date of de-designation will remain in OCI until a disposal of the related U.S. foreign operation occurs. These instruments were designated as part of the Corporation's net investment hedge at Dec. 31, 2011.

ii. Effect of Net Investment Hedges

The following table summarizes the pre-tax amounts recognized in and reclassified out of OCI related to net investment hedges:

Year ended Dec. 31, 2012

Financial instruments in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) reclassified from OCI**	**Pre-tax (gain) reclassified from OCI**
Long-term debt	**19**	Foreign exchange	**–**
Foreign currency contracts	**(4)**	Foreign exchange	**–**
OCI impact	**15**	**OCI impact**	**–**

Year ended Dec. 31, 2011

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) reclassified from OCI	Pre-tax (gain) reclassified from OCI
Long-term debt	(23)	Foreign exchange	–
Foreign currency contracts	(15)	Foreign exchange	–
OCI impact	(38)	OCI impact	–

Year ended Dec. 31, 2010

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) reclassified from OCI	Pre-tax (gain) reclassified from OCI
Long-term debt	68	Foreign exchange	(3)
Foreign currency contracts	(29)	Foreign exchange	–
OCI impact	39	OCI impact	(3)

For the year ended Dec. 31, 2012, a net after-tax loss of $10 million (2011 – loss of $1 million, 2010 – loss of $24 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI. All net investment hedges currently have no ineffective portion.

b. Cash Flow Hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2012**		2011	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**5,624**	**–**	7,817	4
Natural gas *(GJ)*	**570**	**37,827**	2,032	39,022
Oil *(gallons)*	**–**	**4,116**	–	6,300

During 2012, unrealized pre-tax gains of $90 million (2011 - $207 million gain, 2010 - $43 million gain), related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes, were released from AOCI and recognized in net earnings. The cash flow hedges were in respect of future power production expected to occur during 2012 and 2013. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using current forward prices that will change between now and the time the contracts will be settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts will not change.

During 2012, the Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Dec. 31, 2012, cumulative gains of $2 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur.

ii. Foreign Currency Rate Risk Management

The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign denominated debt not designated as a net investment hedge.

As at Dec. 31	2012				2011		
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Exchange Forward Contracts – foreign denominated receipts/expenditures							
USD3	**CAD3**	**–**	**2013**	USD8	CAD8	–	2012
CAD32	**EUR25**	**1**	**2013**	CAD103	EUR74	(6)	2012
CAD245	**USD228**	**(12)**	**2013-2017**	CAD250	USD233	(8)	2012-2017
Foreign Exchange Forward Contracts – foreign denominated debt							
CAD50	**USD50**	**–**	**2013**	–	–	–	–
CAD314	**USD300**	**(14)**	**2013**	CAD314	USD300	(5)	2013
CAD100	**USD100**	**–**	**2013**	–	–	–	–
CAD308	**USD300**	**(8)**	**2013**	–	–	–	–
–	**–**	**–**	**–**	CAD312	USD300	(5)	2012
Cross-Currency Swaps – foreign denominated debt							
CAD530	**USD500**	**(28)**	**2015**	CAD530	USD500	(22)	2015

iii. Interest Rate Risk Management

As at Dec. 31, 2012, the Corporation does not have any forward starting interest rate swaps outstanding. At Dec. 31, 2011, the outstanding forward starting interest rate swaps had fixed rates ranging from 2.75 per cent to 3.43 per cent. Forward starting interest rate swaps are used to offset the variability in cash flows resulting from anticipated issuances of long-term debt.

As at Dec. 31	2012		2011		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
–	**–**	**–**	USD300	(25)	2012

iv. Effect of Cash Flow Hedges

The following tables summarize the pre-tax amounts recognized in and reclassified out of OCI related to cash flow hedges:

Year ended Dec. 31, 2012

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**36**	Revenue	**15**	Revenue	**(90)**
Foreign exchange forwards on commodity contracts	**(3)**	Revenue	**1**	Revenue	**-**
Foreign exchange forwards on project hedges	**(3)**	Property, plant, and equipment	**7**	Foreign exchange (gain) loss	**-**
Foreign exchange forwards on U.S. debt hedges	**(20)**	Foreign exchange (gain) loss	**30**	Foreign exchange (gain) loss	**-**
Cross-currency swaps	**(6)**	Foreign exchange (gain) loss	**13**	Foreign exchange (gain) loss	**-**
Forward starting interest rate swaps	**(15)**	Interest expense	**2**	Interest expense	**3**
OCI impact	**(11)**	**OCI impact**	**68**	**Net earnings impact**	**(87)**

Year ended Dec. 31, 2011

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(92)	Revenue	(43)	Revenue	(207)
Foreign exchange forwards on project hedges	(3)	Property, plant, and equipment	-	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt hedges	3	Foreign exchange (gain) loss	(36)	Foreign exchange (gain) loss	-
Cross-currency swaps	7	Foreign exchange (gain) loss	13	Foreign exchange (gain) loss	-
Forward starting interest rate swaps	(25)	Interest expense	2	Interest expense	-
OCI impact	(110)	OCI impact	(64)	Net earnings impact	(207)

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) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	282	Revenue	(191)	Revenue	(43)
Foreign exchange forwards on project hedges	(15)	Property, plant, and equipment	11	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt hedges	(14)	Foreign exchange (gain) loss	13	Foreign exchange (gain) loss	-
Cross-currency swaps	(10)	Foreign exchange (gain) loss	26	Foreign exchange (gain) loss	-
Forward starting interest rate swaps	(9)	Interest expense	1	Interest expense	-
OCI impact	234	OCI impact	(140)	Net earnings impact	(43)

Over the next 12 months, the Corporation estimates that $13 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural 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.

c. *Fair Value Hedges*

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (Dec. 31, 2011 – 5.75 and 6.65 per cent) to a floating interest rate based on the U.S. LIBOR rate through interest rate swaps as outlined below:

As at Dec. 31	**2012**		2011		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD50	**10**	**2018**	USD150	25	2018

Including the interest rate swaps above, 24 per cent of the Corporation's debt as at Dec. 31, 2012 is subject to floating interest rates (Dec. 31, 2011 – 23 per cent).

ii. Effects of Fair Value Hedges

The following table summarizes the pre-tax impact on the Consolidated Statements of Earnings (Loss) of fair value hedges, including any ineffective portion:

Year ended Dec. 31		**2012**	2011	2010
Derivatives in fair value hedging relationships	**Location of gain (loss) recognized in earnings**			
Interest rate contracts	Net interest expense	**(16)**	4	8
Long-term debt	Net interest expense	**15**	(3)	(8)
Earnings (loss) impact		**(1)**	1	–

II. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, 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*

As at Dec. 31	**2012**		2011	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**40,962**	**32,051**	56,374	47,133
Natural gas *(GJ)*	**1,021,137**	**1,018,557**	1,007,959	1,030,710
Transmission *(MWh)*	**–**	**4,944**	–	2,908
Emissions *(tonnes)*	**138**	**128**	–	–
Oil *(gallons)*	**–**	**7,560**	–	6,552

b. *Other Non-Hedge Derivatives*

As at Dec. 31	**2012**			2011			
Notional amount sold	**Notional amount purchased**	**Fair value asset**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Exchange Forward Contracts							
CAD21	**AUD20**	**–**	**2013**	CAD37	AUD36	–	2012
CAD127	**USD128**	**1**	**2013-2014**	CAD19	USD19	–	2012

c. *Total Return Swaps*

The Corporation 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 applied. 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.

d. Effect of Non-Hedges

For the year ended Dec. 31, 2012, the Corporation recognized a net unrealized loss of $123 million (2011 – gain of $123 million, 2010 – gain of $33 million) related to commodity derivatives.

For the year ended Dec. 31, 2012, a loss of $4 million (2011 – loss of $4 million, 2010 – nil) related to foreign exchange and other derivatives was recognized and is comprised of a net unrealized gain of $1 million (2011 – gain of $3 million, 2010 – gain of $2 million) and a net realized loss of $5 million (2011 – loss of $7 million, 2010 – loss of $2 million).

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 the Corporation's expected own use requirements and 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, 2012 associated with the Corporation's proprietary energy trading activities was $2 million (2011 – $5 million, 2010 – $5 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 Policy 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. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these 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 AOCI, 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, 2012 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $5 million (2011 – $5 million, 2010 – $52 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or for 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, 2012 associated with these transactions was $9 million (2011 – $9 million, 2010 – $6 million).

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 under the 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, 2012, 2011, and 2010, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, 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 over the next quarter in market interest rates.

Year ended Dec. 31	**2012**		2011		2010	
	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**	**–**	4	(8)	4	–

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, the U.S. dollar, and the Australian dollar, 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, 2012, 2011, and 2010, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average five cent (2011 – six cent, 2010 – 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	**2012**		2011		2010	
Currency	**Net earnings decrease**[1]	**OCI gain**[1,2]	Net earnings decrease[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
USD	**(2)**	**11**	(4)	11	(4)	9
AUD	**–**	**–**	–	–	1	–
EUR	**–**	**1**	–	3	–	–
Total	**(2)**	**12**	(4)	14	(3)	9

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 designated as hedging instruments in net investment hedges has 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 the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Thermal PPAs as receivables are substantially all secured by letters of credit.

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, 2012:

(Per cent)	Investment grade	Non-investment grade	Total
Accounts receivable	92	8	100
Risk management assets	96	4	100

The Corporation's maximum exposure to credit risk at Dec. 31, 2012, 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 Statements of Financial Position. 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 (see Note 36) and including the fair value of open trading, net of any collateral held, at Dec. 31, 2012 was $25 million (2011 – $38 million).

At Dec. 31, 2012, 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 has evaluated the risk of default related to this counterparty to be minimal.

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 15.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for 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 financial position 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 the Board of Directors; and maintaining investment grade credit ratings.

A maturity analysis of the Corporation's net financial liabilities, as at Dec. 31, 2012, is as follows:

	2013	2014	2015	2016	2017	2018 and thereafter	Total
Accounts payable and accrued liabilities	495	–	–	–	–	–	495
Collateral received	2	–	–	–	–	–	2
Debt[1]	607	209	654	680	2	2,055	4,207
Energy trading risk management (assets) liabilities	(49)	(25)	6	8	7	7	(46)
Other risk management (assets) liabilities	23	3	30	2	1	(10)	49
Interest on long-term debt	212	185	153	138	127	802	1,617
Dividends payable	75	–	–	–	–	–	75
Total	**1,365**	**372**	**843**	**828**	**137**	**2,854**	**6,399**

1 *Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2013, 2014, and 2016.*

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2012, the Corporation provided $19 million (2011 – $45 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, 2012, the Corporation received $2 million (2011 – $16 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their 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 falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2012, the Corporation had posted collateral of $85 million (2011 – $62 million) in the form of letters of credit on derivative instruments primarily 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 $77 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2012.

18. Restricted Cash

The Corporation has $2 million of cash and cash equivalents at Dec. 31, 2012 (2011 – $17 million) that is restricted for Project Pioneer and not available for general use.

19. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2012	2011
Coal	**76**	78
Natural gas	**2**	5
Purchased emission credits	**4**	2
Total	**82**	85

The change in inventory is as follows:

Balance, Dec. 31, 2010	53
Net additions	30
Change in foreign exchange rates	2
Balance, Dec. 31, 2011	85
Net additions	42
Writedowns	(52)
Reversal of writedowns	8
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2012	**82**

During 2012, the Corporation recognized a $44 million net writedown on coal inventory at the Centralia Thermal plant. The $44 million net writedown was comprised of a $52 million writedown and an $8 million reversal. The $52 million writedown resulted from the previous de-designation of hedges at Centralia Thermal and the continued low price environment in the Pacific Northwest. The de-designation prevents the Corporation from including these contracts as part of the calculation of the net recoverable amount of the inventory. The $8 million reversal resulted due to quarter over quarter recoveries in power prices and reduced operating costs.

No inventory is pledged as security for liabilities.

20. Income Taxes 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. The appeal decision from the Federal Court was received on Jan. 20, 2012, and the ruling was in TransAlta's favour. The Crown had 60 days from the date of judgment to appeal the decision. No appeal was filed by the Crown. TransAlta has received $9 million in 2012, and expects to receive the remaining $2 million during the first quarter of 2013.

21. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of property, plant, and equipment is as follows:

	Land	Thermal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construc-tion	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2010	71	4,567	1,793	2,426	920	982	246	11,005
Additions	–	1	–	–	–	448	4	453
Disposals	–	(1)	(3)	–	(1)	–	(1)	(6)
Asset impairment charges *(Note 11)*	–	–	–	(17)	–	–	–	(17)
Revisions and additions to decommissioning and restoration costs	–	12	2	6	7	–	–	27
Retirement of assets	–	(70)	(23)	(4)	(8)	–	(5)	(110)
Change in foreign exchange rates	–	28	7	–	1	–	–	36
Acquisitions	–	–	–	10	–	–	–	10
Transfers	3	1,002	67	85	26	(1,234)	39	(12)
As at Dec. 31, 2011	74	5,539	1,843	2,506	945	196	283	11,386
Additions	–	–	–	1	–	683	19	703
Disposals	–	(10)	(1)	–	–	–	–	(11)
Asset impairment charges *(Notes 7 and 11)*	–	(378)	–	(18)	(12)	–	–	(408)
Asset impairment reversal *(Note 11)*	–	29	–	–	12	–	–	41
Revisions and additions to decommissioning and restoration costs	–	(14)	11	(4)	(6)	–	–	(13)
Retirement of assets	–	(145)	(22)	(8)	(9)	–	(1)	(185)
Change in foreign exchange rates	–	(20)	(1)	–	(1)	(1)	(1)	(24)
Transfers	1	383	40	59	30	(536)	15	(8)
As at Dec. 31, 2012	**75**	**5,384**	**1,870**	**2,536**	**959**	**342**	**315**	**11,481**
Accumulated depreciation								
As at Dec. 31, 2010	–	2,196	733	368	376	–	57	3,730
Depreciation	–	242	98	84	41	–	10	475
Disposals	–	–	–	(1)	(1)	–	–	(2)
Retirement of assets	–	(63)	(19)	(2)	(6)	–	–	(90)
Change in foreign exchange rates	–	11	4	–	1	–	–	16
Transfers	–	–	(14)	–	–	–	–	(14)
As at Dec. 31, 2011	–	2,386	802	449	411	–	67	4,115
Depreciation	–	257	97	87	38	–	12	491
Retirement of assets	–	(120)	(17)	(3)	(6)	–	–	(146)
Change in foreign exchange rates	–	(13)	(1)	–	(1)	–	–	(15)
Transfers	–	–	(7)	(1)	–	–	–	(8)
As at Dec. 31, 2012	**–**	**2,510**	**874**	**532**	**442**	**–**	**79**	**4,437**
Carrying amount								
As at Dec. 31, 2010	71	2,371	1,060	2,058	544	982	189	7,275
As at Dec. 31, 2011	74	3,153	1,041	2,057	534	196	216	7,271
As at Dec. 31, 2012	**75**	**2,874**	**996**	**2,004**	**517**	**342**	**236**	**7,044**

1 *Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventative, or planned maintenance.*

The Corporation capitalized $4 million of interest to PP&E in 2012 (2011 – $31 million) at a weighted average rate of 5.41 per cent (2011 – 5.34 per cent).

In 2011, the Corporation wrote down certain capital spares to their estimated recoverable amount, resulting in a $4 million pre-tax increase in the depreciation expense of the Generation Segment.

22. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions, as follows:

As at Dec. 31	2012	2011
Energy Trading	**30**	30
Renewables	**417**	417
Total goodwill	**447**	447

In assessing whether goodwill is impaired, the carrying amount of the CGUs (including goodwill) is compared with the recoverable amount of the CGU. The recoverable amount is the higher of fair value less costs to sell and value in use. The impairment review for goodwill is conducted annually. The recoverable amounts exceeded the carrying amounts of the CGUs and there was no impairment of goodwill in 2012, 2011, or 2010.

Goodwill – Renewables

In testing the goodwill of the renewables CGU in 2012, the Corporation relied on the detailed calculation of the recoverable amount made in 2011. Accordingly, the information disclosed below regarding the estimates used to measure recoverable amounts relates to the 2011 calculation.

The Corporation determined the recoverable amount of the renewables CGU by calculating its fair value less cost to sell using discounted cash flow projections. The Corporation's long-range forecasts, which represent forecasted cash flows for generating facilities over their expected useful lives, ranging from 8 to 58 years, are the primary source of information for determining fair value. They contain forecasts for electricity production, sale, revenues, operating costs, and capital expenditures. In developing these plans, various assumptions, such as electricity prices, natural gas prices, and cost inflation rates are established by senior management. These assumptions take into account existing and forecast prices, regional supply-demand balances, other macroeconomic factors, and historical trends and variability. The results of the long-range forecasts are reviewed and approved by senior management.

The key assumptions impacting the determination of fair value for the renewables CGU are electricity production and sales prices. Forecasts of electricity production for each plant are determined taking into consideration contracts for the sale of electricity, historic production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each plant are determined by taking into consideration contract prices for plants subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the plant's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Discount rates used for the renewables goodwill impairment calculation ranged from 5.3 per cent to 7.7 per cent.

No reasonably possible change in the assumptions would result in any impairment of goodwill.

23. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2010	147	108	173	14	442
Additions	5	2	–	23	30
Retirements	–	(2)	–	–	(2)
Transfers	–	19	–	(19)	–
As at Dec. 31, 2011	152	127	173	18	470
Additions	6	–	–	33	39
Retirements	–	(5)	–	–	(5)
Transfers	–	11	–	(11)	–
As at Dec. 31, 2012	**158**	**133**	**173**	**40**	**504**
Accumulated amortization					
As at Dec. 31, 2010	92	59	11	–	162
Amortization	4	22	8	–	34
Retirements	–	(2)	–	–	(2)
As at Dec. 31, 2011	96	79	19	–	194
Amortization	4	19	8	–	31
Retirements	–	(5)	–	–	(5)
As at Dec. 31, 2012	**100**	**93**	**27**	**–**	**220**
Carrying amount					
As at Dec. 31, 2010	55	49	162	14	280
As at Dec. 31, 2011	56	48	154	18	276
As at Dec. 31, 2012	**58**	**40**	**146**	**40**	**284**

24. Other Assets

The components of other assets are as follows:

As at Dec. 31	**2012**	2011
Deferred licence fees	**21**	22
Project development costs	**35**	33
Deferred service costs	**19**	18
Keephills Unit 3 transmission deposit	**7**	8
Other	**8**	9
Total other assets	**90**	90

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences 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. In 2011, the Corporation wrote off $6 million of project development costs associated with the Saint-Valentin wind project.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next nine years, as long as certain performance criteria are met.

25. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2010	285	–	25	310
Liabilities incurred	20	–	67	87
Liabilities settled	(33)	–	(14)	(47)
Accretion	18	–	1	19
Disposals	(1)	–	(1)	(2)
Revisions in estimated cash flows	2	–	4	6
Revisions in discount rates	8	–	–	8
Reversals	–	–	(1)	(1)
Change in foreign exchange rates	2	–	–	2
Balance, Dec. 31, 2011	301	–	81	382
Liabilities incurred	16	13	56	85
Liabilities settled	(44)	(5)	(17)	(66)
Accretion	16	–	1	17
Disposals	–	–	–	–
Revisions in estimated cash flows	(11)	–	2	(9)
Revisions in discount rates	(15)	–	–	(15)
Reversals[1]	–	–	(81)	(81)
Change in foreign exchange rates	(1)	–	–	(1)
Balance, Dec. 31, 2012	**262**	**8**	**42**	**312**

1 *Includes Sundance Units 1 and 2 and Sundance Unit 3 provisions that were reversed as a result of the conclusions of the respective arbitration decisions in 2012.*

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2011	301	-	81	382
Current portion	26	-	73	99
Non-current portion	275	-	8	283
Balance, Dec. 31, 2012	**262**	**8**	**42**	**312**
Current portion	13	8	12	33
Non-current portion	249	-	30	279

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.0 billion, which will be incurred between 2013 and 2072. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2012, the Corporation had provided a surety bond in the amount of U.S.$136 million (2011 – U.S.$131 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2012, the Corporation had provided letters of credit in the amount of $79 million (2011 – $69 million) in support of future decommissioning obligations at the Alberta mine.

B. Restructuring Provisions (see Note 4)

The provision relates to the Corporation's restructuring of resources as part of its ongoing strategy to continuously improve operational excellence and accelerate growth.

C. Other Provisions

Other provisions include an amount related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2018.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

26. Long-Term Debt

A. Amounts Outstanding

As at Dec. 31	2012			2011		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**950**	**950**	**2.4%**	806	806	2.1%
Debentures	**839**	**851**	**6.6%**	833	851	6.6%
Senior notes[3]	**2,017**	**1,990**	**5.6%**	1,979	1,940	6.0%
Non-recourse[4]	**375**	**380**	**5.9%**	375	382	5.9%
Other	**36**	**36**	**6.5%**	44	44	6.6%
	4,217	**4,207**		4,037	4,023	
Less: recourse current portion	**(606)**	**(606)**		(314)	(314)	
Less: non-recourse current portion	**(1)**	**(1)**		(2)	(2)	
Total long-term debt	**3,610**	**3,600**		3,721	3,707	

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. Includes U.S.$300 million at Dec. 31, 2012 (2011 – U.S.$300 million).*
3 *U.S. face value at Dec. 31, 2012 – U.S.$2.0 billion (2011 – U.S.$1.9 billion).*
4 *Includes U.S.$20 million at Dec. 31, 2012 (2011 – U.S.$20 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 (see Note 17) and are recorded at fair value. The balance of long-term debt is not hedged and is 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 business. The facility is a four-year revolving credit facility that was last renewed in April 2012 and matures in 2016. 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' acceptances, U.S. LIBOR, or U.S. base rate, in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities, all of which mature in 2014. The Corporation anticipates renewing these facilities based on reasonable commercial terms, prior to their maturities.

Of the $2.0 billion (2011 – $2.0 billion) of committed credit facilities, $0.8 billion (2011 – $0.9 billion) is not drawn, and is available as of Dec. 31, 2012, subject to customary borrowing conditions. In addition to the $0.8 billion available under the credit facilities, TransAlta also has $25 million of available cash.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent and have maturity dates ranging from 2014 to 2030.

Senior notes bear interest at rates ranging from 4.50 per cent to 6.65 per cent and have maturity dates ranging from 2013 to 2040. A total of U.S.$750 million of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations. During 2012, the Corporation's U.S.$300 million 6.75 per cent senior notes matured and were paid out. In addition, during 2012, the Corporation issued senior notes in the amount of U.S.$400 million, bearing interest at a rate of 4.5 per cent and maturing in 2022.

Non-recourse debt consists of debentures issued by Canadian Hydro Developers, Inc. that have maturity dates ranging from 2013 to 2018 and bear interest at rates ranging from 5.3 per cent to 10.9 per cent. This debt has a carrying value of $360 million and U.S.$20 million. The U.S.$20 million has been designated as a hedge of the Corporation's net investment in U.S. foreign operations.

Other consists of notes payable for the Windsor plant that bear interest at a fixed rate of 7.4 per cent, mature in November 2014, and are recourse to the Corporation through a standby letter of credit and an unsecured commercial loan obligation that bears interest at a rate of 5.9 per cent, matures in 2023, and requires annual blended 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, 2012, the Corporation was in compliance with all debt covenants.

B. Principal Repayments

2013	607
2014	209
2015	654
2016	680
2017	2
2018 and thereafter	2,055
Total[1]	**4,207**

1 *Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2013, 2014, and 2016.*

C. Guarantees

Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and 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 under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2012 were $336 million (2011 – $328 million) with no (2011 – nil) amounts exercised by third parties under these arrangements.

27. Deferred Credits and Other Long-Term Liabilities

The components of deferred credits and other long-term liabilities are as follows:

As at Dec. 31	2012	2011
Deferred coal revenues	**51**	52
Defined benefit obligations *(Note 32)*	**220**	190
Long-term incentive accruals	**15**	18
Other	**15**	21
Total deferred credits and other long-term liabilities	**301**	281

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint venture for future coal deliveries. These amounts are being amortized into revenue over the life of the coal supply agreement, since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

28. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

As at Dec. 31	2012		2011	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**223.6**	**2,274**	220.3	2,205
Issued under the dividend reinvestment and share purchase plan	**9.7**	**159**	3.2	67
Issued under share-based payment plans *(Note 31)*	**0.1**	**1**	0.1	2
Issued under the PSOP *(Note 31)*	**0.1**	**1**	–	–
Issued under public offering[1]	**21.2**	**295**	–	–
	254.7	**2,730**	223.6	2,274
Amounts receivable under Employee Share Purchase Plan *(Note 31)*	**–**	**(4)**	–	(1)
Issued and outstanding, end of year	**254.7**	**2,726**	223.6	2,273

1 *Net of after-tax issuance costs of $9 million ($12 million issuance costs, less tax-effects of $3 million).*

On Sept. 13, 2012, TransAlta completed a public offering of 19,250,000 common shares at a price of $14.30 per common share. TransAlta granted the underwriters an over-allotment option to purchase up to an additional 2,887,500 common shares at the same price. On Sept. 20, 2012, the underwriters exercised in part their over-allotment option and purchased an additional 1,992,000 common shares at $14.30 per common share for total gross proceeds of $304 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 Shareholder Rights Plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and was last approved on April 29, 2010. As such, the Shareholder Rights Plan will be put before the Corporation's shareholders at the Corporation's Annual and Special Meeting of Shareholders on April 23, 2013 for a vote to be renewed, continued, ratified, and approved.

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. Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan

On February 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan is called the Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan ("the Plan") and provides eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component). The discount on reinvested dividends can be adjusted to between zero and five per cent at the discretion of the Board of Directors. Participants are also eligible to purchase new shares at a three per cent discount to the average market price under the optional cash payment component (the OCP Component) of the Plan by directly investing up to $5,000 per quarter. Eligible shareholders are not required to participate in the Plan. Those shareholders who have not elected or been deemed to have elected to participate in the Plan will continue to receive their quarterly cash dividends in the usual manner.

During the year ended Dec. 31, 2012, the Corporation issued 9.7 million common shares (2011 – 3.2 million) for $159 million (2011 – $67 million) for dividends reinvested under the Plan.

Of the dividend that was payable on Jan. 1, 2013, 72 per cent was settled through the dividend reinvestment option under the Plan.

D. Earnings Per Share

Year ended Dec. 31	2012	2011	2010
Net earnings (loss) attributable to common shareholders	**(613)**	290	255
Basic and diluted weighted average number of common shares outstanding	**235**	222	219
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(2.61)**	1.31	1.16

The effect of the stock options, PSOP, and the Plan does not materially affect the calculation of the total weighted average number of common shares outstanding (see Note 31).

E. Dividends

The following table summarizes the common share dividends declared in 2012, 2011, and 2010:

Date declared	Payment date	Dividend per share ($)	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Jan. 25, 2012	**Apr. 1, 2012**	**0.29**	**65**	**23**	**43**
Apr. 25, 2012	**July 1, 2012**	**0.29**	**66**	**18**	**48**
July 13, 2012	**Oct. 1, 2012**	**0.29**	**67**	**18**	**49**
Oct. 24, 2012	**Jan. 1, 2013**	**0.29**	**73**	**20**	**53**
Total		**1.16**	**271**		

Date declared	Payment date	Dividend per share ($)	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Apr. 28, 2011	July 1, 2011	0.29	64	48	16
July 27, 2011	Oct. 1, 2011	0.29	65	48	17
Oct. 27, 2011	Jan. 1, 2012	0.29	65	45	20
Total		0.87	194		

Date declared	Payment date	Dividend per share ($)	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
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	46	17
Oct. 28, 2010	Jan. 1, 2011	0.29	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	48	17
Total		1.45	319		

29. Preferred Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares. The rights, privileges, restrictions, and conditions attaching to such shares are determined by the Board of Directors, subject to certain limitations.

Year ended Dec. 31, 2012

	Number of shares *(millions)*	Amount	Dividend rate per share *($)*	Redemption price per share *($)*
Issued and outstanding, beginning of year	**23**	**562**	**1.15**	**25.00**
Issued[1]	**9**	**219**	**1.25**	**25.00**
Issued and outstanding, end of year	**32**	**781**		

1 *Net of after-tax issuance costs of $6 million ($8 million issuance costs, less tax-effects of $2 million).*

Year ended Dec. 31, 2011

	Number of shares *(millions)*	Amount	Dividend rate per share *($)*	Redemption price per share *($)*
Issued and outstanding, beginning of year	12	293	1.15	25.00
Issued[2]	11	269	1.15	25.00
Issued and outstanding, end of year	23	562		

2 *Net of after-tax issuance costs of $6 million ($8 million issuance costs, less tax-effects of $2 million).*

On Aug. 10, 2012, TransAlta completed a public offering of 9 million Series E Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $225 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.25 per share as approved by the Board of Directors, payable quarterly, yielding 5.0 per cent per annum, for the initial period ending Sept. 30, 2017. The dividend rate will reset on Sept. 30, 2017 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 3.65 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2017 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends.

The Series E preferred shareholders will have the right at their option to convert their shares into Series F Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2017 and on Sept. 30 of every fifth year thereafter. The holders of Series F 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 3.65 per cent.

On Nov. 30, 2011, TransAlta completed a public offering of 11 million Series C Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $275 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 June 30, 2017. The dividend rate will reset on June 30, 2017 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 3.10 per cent. The preferred shares are redeemable at the option of TransAlta on or after June 30, 2017 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends.

The Series C preferred shareholders will have the right at their option to convert their shares into Series D Cumulative Redeemable Rate Reset First Preferred Shares on June 30, 2017 and on June 30 of every fifth year thereafter. The holders of Series D 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 3.10 per cent.

B. Dividends

The following tables summarize the preferred share dividends declared in 2012, 2011, and 2010:

Series A Cumulative Redeemable Rate Reset First Preferred Shares

Date declared	Payment date	Dividend per share ($)	Total dividends
Jan. 25, 2012	**March 31, 2012**	**0.2875**	**3**
Apr. 25, 2012	**June 30, 2012**	**0.2875**	**4**
July 13, 2012	**Sept. 30, 2012**	**0.2875**	**4**
Oct. 24, 2012	**Dec. 31, 2012**	**0.2875**	**3**
Total		**1.15**	**14**

Date declared	Payment date	Dividend per share ($)	Total dividends
Apr. 28, 2011	June 30, 2011	0.2875	3
July 27, 2011	Sept. 30, 2011	0.2875	4
Oct. 27, 2011	Dec. 31, 2011	0.2875	4
Total		0.8625	11

Date declared	Payment date	Dividend per share ($)	Total dividends
Dec. 13, 2010[1]	March 31, 2011	0.3497	4
Total		0.3497	4

1 *Includes dividends of $0.0622 per share ($1 million in total) for the period from Dec. 10, 2010 to Dec. 31, 2010, which were accrued at Dec. 31, 2010.*

Series C Cumulative Redeemable Rate Reset First Preferred Shares

Date declared	Payment date	Dividend per share ($)	Total dividends
Jan. 25, 2012[2]	**March 31, 2012**	**0.3844**	**4**
Apr. 25, 2012	**June 30, 2012**	**0.2875**	**3**
July 13, 2012	**Sept. 30, 2012**	**0.2875**	**3**
Oct. 24, 2012	**Dec. 31, 2012**	**0.2875**	**4**
Total		**1.2469**	**14**

2 *Includes dividends of $0.0969 per share ($1 million in total) for the period from Nov. 29, 2011 to Dec. 31, 2011, which were accrued at Dec. 31, 2011.*

Series E Cumulative Redeemable Rate Reset First Preferred Shares

Date declared	Payment date	Dividend per share ($)	Total dividends
Oct. 24, 2012	**Dec. 31, 2012**	**0.4897**	**4**

30. Accumulated Other Comprehensive Income (Loss)

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2012	2011
Currency translation adjustment		
Opening balance	**(28)**	(27)
Gains (losses) on translating net assets of foreign operations[1]	**(23)**	32
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**13**	(33)
Balance, Dec. 31	**(38)**	(28)
Cash flow hedges		
Opening balance	**(28)**	232
Losses on derivatives designated as cash flow hedges, net of tax[3]	**(7)**	(83)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax[4]	**5**	–
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[5]	**(7)**	(177)
Balance, Dec. 31	**(37)**	(28)
Employee future benefits		
Opening balance	**(46)**	(20)
Net actuarial losses on defined benefit plans, net of tax[6]	**(27)**	(26)
Balance, Dec. 31	**(73)**	(46)
Accumulated other comprehensive loss	**(148)**	(102)

1 *Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – nil).*
2 *Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – 5 recovery).*
3 *Net of income tax expense of 3 for the year ended Dec. 31, 2012 (2011 – 7 recovery).*
4 *Net of income tax recovery of 2 for the year ended Dec. 31, 2012 (2011 – nil).*
5 *Net of income tax expense of 20 for the year ended Dec. 31, 2012 (2011 – 94 expense).*
6 *Net of income tax recovery of 10 for the year ended Dec. 31, 2012 (2011 – 9 recovery).*

31. Share-Based Payment Plans

At Dec. 31, 2012, the Corporation had two types of share-based payment 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 is 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.

IV. Total Plan Information

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2012 is outlined below:

	Options outstanding			Options exercisable	
Range of exercise prices *($ per share)*	**Number outstanding at Dec. 31, 2012** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*	**Number exercisable at Dec. 31, 2012** *(millions)*	**Weighted average exercise price** *($ per share)*
10.85-16.89	**0.1**	**2.2**	**14.35**	**0.1**	**14.35**
16.90-22.94	**0.8**	**6.1**	**21.23**	**0.5**	**20.65**
22.95-28.99	**–**	**–**	**–**	**–**	**–**
29.00-35.05	**0.6**	**5.1**	**31.95**	**0.6**	**31.95**
10.85-35.05	**1.5**	**5.5**	**25.35**	**1.2**	**26.23**

The change in the number of options outstanding under the option plans is outlined below:

Year ended Dec. 31	**2012**		2011		2010	
	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	**1.7**	**25.10**	2.2	24.94	1.5	26.36
Granted	**–**	**–**	–	–	0.9	22.27
Exercised	**–**	**–**	–	–	(0.1)	16.20
Forfeited	**(0.2)**	**22.81**	(0.5)	25.35	(0.1)	26.61
Outstanding, end of year	**1.5**	**25.35**	1.7	25.10	2.2	24.94

The Corporation uses the fair value method of accounting for awards granted under its stock option plans.

No stock options were granted in 2012 or 2011. 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 instalments over four years starting Feb. 1, 2011 and expire after 10 years. The estimated weighted average fair value of these options granted was determined using the Black-Scholes option-pricing model and the following weighted average assumptions, resulting in a weighted average fair value of $3.63 per option:

	2010
Risk-free interest rate *(%)*	2.4
Expected life of the options *(years)*	5.0
Dividend rate *(%)*	5.1
Volatility in the price of the corporation's shares *(%)*	29.4

The expected life of the option and volatility in the share price is based on historical data and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the option is indicative of future trends, which may also not necessarily be the actual outcome.

The expense recognized arising from equity-settled share-based payment transactions was $1 million (2011 – $2 million, 2010 – $2 million).

B. Performance Share Ownership Plan

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to award 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 that, after three years, make them eligible to receive a set number of common shares, including the value of reinvested dividends over the period, or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. The ultimate awarding of PSOP in any year is at the discretion of TransAlta's Human Resource Committee ("HRC"). 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 use share settlements 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. If the awards are paid out in cash, they are paid immediately. 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. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued using the closing share price.

Year ended Dec. 31 *(millions)*	**2012**	2011	2010
Number of grants outstanding, beginning of year	**2.5**	1.7	1.0
Granted	**1.5**	1.4	1.2
Awarded by HRC	**(0.1)**	–	(0.2)
Forfeited	**(1.0)**	(0.6)	(0.3)
Number of grants outstanding, end of year	**2.9**	2.5	1.7

In 2012, pre-tax PSOP compensation expense was $3 million (2011 – $9 million, 2010 – $7 million), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss). In 2012, 55,418 common shares (2011 – 50,560, 2010 – 166,169 common shares) were issued at $15.12 per share (2011 – $21.15 per share, 2010 – $23.48 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. An agent 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, 2012, amounts receivable from employees under the plan totalled $4 million (Dec. 31, 2011 – $1 million).

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 Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned.

The latest actuarial valuations for accounting purposes of the Canadian and U.S. pension plans was at Dec. 31, 2012 and Jan. 1, 2012, respectively. The measurement date used to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2012. The last actuarial valuation for funding purposes of the Canadian registered plan was completed in early 2012 with an effective date of Dec. 31, 2011. The last actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2012. It is the Corporation's practice to complete funding valuations annually, although they are not required to be filed with regulators annually.

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 $64 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 through its other post-employment benefits plans. The latest actuarial valuation of the Canadian and U.S. plans was as at Dec. 31, 2010 and Jan. 1, 2012, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2012.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution, and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2012	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**2**	**2**	**1**	**5**
Interest cost	**18**	**3**	**2**	**23**
Expected return on plan assets	**(17)**	**–**	**–**	**(17)**
Defined benefit expense[1]	**3**	**5**	**3**	**11**
Defined contribution expense	**20**	**–**	**–**	**20**
Net expense	**23**	**5**	**3**	**31**

1 *Amendments to IAS 19 are effective Jan. 1, 2013. See Note 3 for more details.*

Year ended Dec. 31, 2011	Registered	Supplemental	Other	Total
Current service cost	2	2	2	6
Interest cost	19	4	1	24
Expected return on plan assets	(21)	–	–	(21)
Past service costs	–	1	–	1
Defined benefit expense	–	7	3	10
Defined contribution expense	19	–	–	19
Net expense	19	7	3	29

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Current service cost	2	2	2	6
Interest cost	21	4	2	27
Expected return on plan assets	(21)	–	–	(21)
Curtailment	(1)	–	(1)	(2)
Defined benefit expense	1	6	3	10
Defined contribution expense	19	–	–	19
Net expense	20	6	3	29

The amounts recognized in OCI during the year are as follows:

	Registered	Supplemental	Other	Total
Balance, Dec. 31, 2010	(23)	(8)	3	(28)
Actuarial loss	(31)	(3)	(1)	(35)
Balance, Dec. 31, 2011	(54)	(11)	2	(63)
Actuarial loss	(29)	(7)	(1)	(37)
Balance, Dec. 31, 2012	**(83)**	**(18)**	**1**	**(100)**

The history of experience adjustments is as follows:

Year ended Dec. 31, 2012	Registered	Supplemental	Other	Total
Experience adjustments on plan assets	6	–	–	6
Experience adjustments on plan liabilities	(35)	(7)	(1)	(43)

Year ended Dec. 31, 2011	Registered	Supplemental	Other	Total
Experience adjustments on plan assets	(10)	–	–	(10)
Experience adjustments on plan liabilities	(21)	(3)	(1)	(25)

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2012	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**294**	**5**	**–**	**299**
Present value of defined benefit obligation	**424**	**77**	**34**	**535**
Funded status – plan deficit	**(130)**	**(72)**	**(34)**	**(236)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(9)**	**(5)**	**(2)**	**(16)**
Other long-term liabilities	**(121)**	**(67)**	**(32)**	**(220)**
Total amount recognized	**(130)**	**(72)**	**(34)**	**(236)**

As at Dec. 31, 2011	Registered	Supplemental	Other	Total
Fair value of plan assets	294	5	–	299
Present value of defined benefit obligation	396	71	32	499
Funded status – plan deficit	(102)	(66)	(32)	(200)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(3)	(4)	(3)	(10)
Other long-term liabilities	(99)	(62)	(29)	(190)
Total amount recognized	(102)	(66)	(32)	(200)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Fair value of plan assets as at Dec. 31, 2010	304	4	–	308
Expected return on plan assets[1]	21	–	–	21
Contributions	7	5	2	14
Benefits paid	(28)	(4)	(2)	(34)
Actuarial losses on plan assets[2]	(10)	–	–	(10)
Fair value of plan assets as at Dec. 31, 2011	294	5	–	299
Expected return on plan assets[1]	17	–	–	17
Contributions	3	6	2	11
Benefits paid	(26)	(6)	(2)	(34)
Actuarial gains on plan assets[2]	6	–	–	6
Fair value of plan assets as at Dec. 31, 2012	**294**	**5**	**–**	**299**

1 *The actual return on plan assets in 2012 was $23 million (2011 – $11 million).*
2 *Net of expenses.*

The allocation of defined benefit pension plan assets by major asset category is as follows:

Year ended Dec. 31, 2012 *(per cent)*	**Registered**	**Supplemental**
Equity securities	**50**	**–**
Debt securities	**48**	**–**
Money market investments	**1**	**–**
Cash and cash equivalents	**1**	**100**
Total	**100**	**100**

Year ended Dec. 31, 2011 *(per cent)*	Registered	Supplemental
Equity securities	49	–
Debt securities	49	–
Money market investments	1	–
Cash and cash equivalents	1	100
Total	100	100

Plan assets do not include any common shares of the Corporation at Dec. 31, 2012 and Dec. 31, 2011. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2012 (Dec. 31, 2011 – $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2010	382	66	29	477
Current service cost	2	2	2	6
Past service cost	–	1	–	1
Interest cost	19	3	2	24
Benefits paid	(28)	(4)	(2)	(34)
Actuarial loss	21	3	1	25
Present value of defined benefit obligation as at Dec. 31, 2011	396	71	32	499
Current service cost	2	2	1	5
Interest cost	18	3	2	23
Benefits paid	(26)	(6)	(2)	(34)
Actuarial loss	35	7	1	43
Effect of translation on U.S. plans	(1)	–	–	(1)
Present value of defined benefit obligation as at Dec. 31, 2012	**424**	**77**	**34**	**535**

F. Contributions

The expected employer contributions for 2013 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	9	5	2	16

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

As at Dec. 31, 2012 *(per cent)*	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation			
Discount rate	**4.0**	**4.0**	**3.9**
Rate of compensation increase	**3.0**	**3.0**	**–**
Assumed health care cost trend rate			
Health care cost escalation	**–**	**–**	**7.4**[1]
Dental care cost escalation	**–**	**–**	**4.0**
Provincial health care premium escalation	**–**	**–**	**3.5**
Benefit cost for the year			
Discount rate	**4.8**	**4.8**	**4.8**
Rate of compensation increase	**3.0**	**3.0**	**–**
Expected rate of return on plan assets	**6.2**	**–**	**–**
Assumed health care cost trend rate			
Health care cost escalation	**–**	**–**	**8.0**[2]
Dental care cost escalation	**–**	**–**	**4.0**
Provincial health care premium escalation	**–**	**–**	**6.0**

1 Pre and post 65 rates; decreasing gradually to five per cent by 2016 – 2019 and remaining at that level thereafter for the U.S. and decreasing gradually to five per cent by 2018 for Canada.
2 Decreasing gradually to five per cent by 2018 for both the U.S. and Canadian plans.

As at Dec. 31, 2011 *(per cent)*	Registered	Supplemental	Other
Accrued benefit obligation			
Discount rate	4.8	4.8	4.8
Rate of compensation increase	3.0	3.0	–
Assumed health care cost trend rate			
Health care cost escalation	–	–	8.0[3]
Dental care cost escalation	–	–	4.0
Provincial health care premium escalation	–	–	6.0
Benefit cost for the year			
Discount rate	5.2	5.3	5.0
Rate of compensation increase	3.0	3.0	–
Expected rate of return on plan assets	7.1	–	–
Assumed health care cost trend rate			
Health care cost escalation	–	–	8.5[3]
Dental care cost escalation	–	–	4.0
Provincial health care premium escalation	–	–	6.0

3 Decreasing gradually to five per cent by 2018 for both the U.S. and Canadian plans.

The expected 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 pension and other post-employment benefit plans if there was a change of +/- one percentage point in the discount rate or the health care cost trend rate:

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2012	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% increase in the discount rate					
Impact on 2012 defined benefit obligation	**(38)**	**(10)**	**(2)**	**(3)**	**(1)**
Impact on 2013 estimated expense	**(1)**	**-**	**-**	**-**	**-**
1% decrease in the discount rate					
Impact on 2012 defined benefit obligation	**45**	**12**	**2**	**4**	**1**
Impact on 2013 estimated expense	**-**	**-**	**-**	**-**	**-**
1% increase in the health care cost trend rate					
Impact on 2012 defined benefit obligation	**-**	**-**	**3**	**-**	**1**
Impact on 2013 estimated expense	**-**	**-**	**-**	**-**	**-**
1% decrease in the health care cost trend rate					
Impact on 2012 defined benefit obligation	**-**	**-**	**(2)**	**-**	**(1)**
Impact on 2013 estimated expense	**-**	**-**	**-**	**-**	**-**

33. Joint Ventures

Joint ventures at Dec. 31, 2012 included the following:

Jointly controlled assets	**Ownership** *(per cent)*	**Description**
Sheerness	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Fort Saskatchewan	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake	50	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power	50	Gas-fired plant in Australia operated by TransAlta
Genesee Unit 3	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	50	Coal-fired plant 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 project (to be discontinued as announced in April 2012)

Jointly controlled entities	**Ownership** *(per cent)*	**Description**
CE Gen	50	Geothermal and gas plants in the United States operated by CE Gen affiliates
Wailuku	50	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company
TransAlta MidAmerican Partnership	50	Strategic partnership to develop, build, and operate new natural gas-fueled electricity generation projects in Canada

34. Changes in Non-Cash Operating Working Capital

Year ended Dec. 31	2012	2011	2010
(Use) source:			
Accounts receivable	(23)	(131)	(7)
Prepaid expenses	3	3	6
Income taxes receivable	(10)	13	17
Inventory	1	(26)	31
Accounts payable and accrued liabilities	34	(20)	15
Provisions	(41)	35	(13)
Income taxes payable	(16)	7	(2)
Change in non-cash operating working capital	**(52)**	(119)	47

35. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2012	2011	Increase/ (decrease)
Current portion of long-term debt	607	316	291
Less: available cash and cash equivalents[1]	(25)	(32)	7
	582	284	298
Long-term debt	3,610	3,721	(111)
Equity			
Common shares	2,726	2,273	453
Preferred shares	781	562	219
Contributed surplus	9	9	–
Retained earnings	(358)	527	(885)
Accumulated other comprehensive loss	(148)	(102)	(46)
Non-controlling interests	330	358	(28)
	6,950	7,348	(398)
Total capital	**7,532**	7,632	(100)

1 The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital as capital is managed internally and evaluated by management using a net debt position. In this regard these funds may be available, and used, to facilitate repayment of debt.

Total capital remains largely unchanged from the beginning of the year. Changes in the balances of the components of capital are as follows:

Long-term debt (including current portion) increased due to an increase in amounts outstanding under credit facilities and a net increase in senior notes (see Note 26).

Common shares increased in 2012 as a result of the issuance of 21.2 million shares through a public offering for gross proceeds of $304 million and 9.7 million shares for $159 million of dividends reinvested (see Note 28).

Preferred shares increased in 2012 as a result of the issuance of 9 million Series E Preferred Shares for gross proceeds of $225 million (see Note 29).

AOCI decreased in 2012 primarily due to the recognition of unrealized losses on derivatives designated as hedging instruments, losses on translating net assets of foreign operations, and net actuarial losses on defined benefit plans (see Note 30).

TransAlta's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2011 and 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 interest 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:

Adjusted cash flow to interest coverage is calculated as cash flow from operating activities before changes in working capital (adjusted for the impacts associated with Sundance Units 1 and 2 arbitration) plus net interest expense divided by interest on debt less interest income. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted cash flow to debt is calculated as cash flow from operating activities before changes in working capital (adjusted for the impacts associated with Sundance Units 1 and 2 arbitration) divided by average total debt less average cash and cash equivalents. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital is calculated as debt less cash and cash equivalents divided by debt, non-controlling interests, and shareholders' equity less cash and cash equivalents. The Corporation's goal is to maintain this ratio in a range of 50 to 55 per cent (2011 – 55 to 60 per cent).

These ratios are outlined below:

As at Dec. 31	**2012**	2011	Target
Adjusted cash flow to interest coverage *(times)*[1]	**4.4**	4.4	Minimum of 4
Adjusted cash flow to debt *(%)*[1]	**18.9**	20.1	Minimum of 20
Debt to invested capital *(%)*	**55.6**	52.5	Maximum of 55

1 *Last 12 months.*

Adjusted cash flow to interest coverage in 2012 was comparable to 2011. Adjusted cash flow to debt decreased in 2012 compared to 2011 due to higher average debt levels. Debt to invested capital increased as at Dec. 31, 2012 compared to 2011 due to higher average debt levels.

These targets represent a prudent range for the Corporation. At times and over a short-term period, the credit ratios may be outside of the specified target ranges while the Corporation re-aligns its capital structure. During 2012, the Corporation took several steps to reduce debt, including adding a Premium Dividend™ component to the dividend reinvestment plan (see Note 28), issuing approximately $300 million of common shares and approximately $225 million of preferred shares.

TransAlta routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and property, plant, and equipment expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Property, Plant, and Equipment

For the year ended Dec. 31, 2012 and 2011, net cash outflows, after cash dividends and property, plant, and equipment additions, are summarized below:

Year ended Dec. 31	**2012**	2011	Increase (decrease) in cash flow
Cash flow from operating activities	**520**	690	(170)
Dividends paid on common shares	**(104)**	(191)	87
Property, plant, and equipment expenditures	**(703)**	(453)	(250)
Acquisition of finance lease	**(312)**	–	(312)
Net cash inflow (outflow)	**(599)**	46	(645)

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2012, $0.8 billion (2011 – $0.9 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, 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 2012, the Corporation issued 31.1 million common shares for total gross proceeds of $456 million. The Corporation also issued 9 million Series E Preferred Shares for total gross proceeds of $225 million.

During 2012, the Corporation's U.S.$300 million 6.75 per cent senior notes matured and were paid out. In addition, during 2012, the Corporation issued senior notes in the amount of U.S.$400 million, bearing interest at a rate of 4.5 per cent and maturing in 2022.

During 2011, the Corporation issued 3.3 million common shares for total proceeds of $69 million. The Corporation also issued 11 million Series C Preferred Shares for total gross proceeds of $275 million.

Dividends on the Corporation's common shares are at the discretion of the Board of Directors. In determining the payment and level of future dividends, the Board of Directors considers the Corporation's financial performance, its results of operations, cash flow and needs with respect to financing ongoing operations and growth, balanced against returning capital to shareholders.

36. 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.$47 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 offsets from outstanding receivables to the refunds awarded by FERC. TransAlta established a U.S.$47 million provision to cover any potential refunds and continues to seek relief from these obligations. Final rulings are not expected in the near future.

37. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries are as follows:

Subsidiary	Country	Ownership *(per cent)*	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy trading
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy trading
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
Canadian Hydro Developers, Inc.	Canada	100	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO, the Chief Officers, the Executive Vice Presidents, and the President – U.S. Operations, all who report directly to the President and CEO, and the Board of Directors. Key management personnel compensation is as follows:

Year ended Dec. 31	2012	2011	2010
Total compensation	**12**	12	11
Comprised of:			
Short-term employee benefits	**8**	6	7
Post-employment benefits	**1**	1	1
Other long-term benefits	**1**	1	1
Share-based payment	**2**	4	2

38. Commitments

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has entered into a number of fixed purchase and transportation contracts, transmission and electricity purchase agreements, coal supply and mining agreements, long-term service agreements, and agreements related to growth and major projects either directly or through its interests in joint ventures. Approximate future payments under these agreements are as follows:

	Natural gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Coal supply and mining agreements	Long-term service agreements	Growth, major, and development project commitments	Total
2013	76	40	125	18	131	390
2014	35	10	102	17	–	164
2015	11	11	96	9	–	127
2016	10	8	98	3	–	119
2017	9	3	25	–	–	37
2018 and thereafter	106	5	530	–	–	641
Total	**247**	**77**	**976**	**47**	**131**	**1,478**

A. Natural Gas, Transportation, and Other Purchase Contracts

Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other fixed price purchase contracts relate to commitments for services at certain facilities.

B. Transmission and Power Purchase Agreements

TransAlta has several agreements to purchase 400 MW of Pacific Northwest transmission network capacity. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

On Oct. 29, 2012, TransAlta was awarded an agreement by Grant County to purchase an estimated 10.135% of the output from a hydro generation facility located in the Pacific Northwest for the period Jan. 1, 2013 to Dec. 31, 2013. The total cost is expected to be $29 million.

C. Coal Supply and Mining Agreements

Centralia Thermal has various coal supply and associated rail transport contracts to provide coal for use in production. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2016.

Effective Jan. 17, 2013, the Corporation will assume operating and management control of the Highvale Mine, which was previously operated under a long-term contract by Prairie Mines and Royalty Ltd. ("PMRL"). Commitments related to mining agreements include final amounts due in 2013 under the PMRL contract and the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint ventures.

D. 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.

E. Growth, Major, and Development Project Commitments

Growth

On March 28, 2011, the Corporation announced it had received approval from the Government of Quebec to proceed with the construction of the 68 MW New Richmond wind project located on the Gaspé Peninsula. New Richmond is contracted under a 20-year Electricity Supply Agreement with Hydro-Québec Distribution. The cost of the project is estimated to be approximately $212 million and commercial operations are expected to commence during the first quarter of 2013.

Major

During the third quarter of 2012, the Corporation entered into an agreement with Alstom Power & Transport Canada Inc. for the manufacture, delivery, and erection of the Sundance Units 1 and 2 waterwalls. The total fixed price commitment under the contract is $79 million. Payments will be made as agreed milestones are achieved. Additional costs to be paid under the contract include reimbursable items, such as direct labour, subcontractors, and labour incentive allowances.

Growth, major, and development project commitments are as follows:

	Sundance Units 1 and 2	New Richmond	Development	Total
2013	112	15	4	131
Total	**112**	**15**	**4**	**131**

F. TransAlta Energy Bill Commitments

As part of the Bill and MoA signed into law in the State of Washington, the Corporation has committed to fund $55 million over the life of the Centralia coal plant to support economic development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination of the MoA this funding will no longer be required.

G. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts include: electricity and thermal capacity, availability and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

39. 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. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta.

40. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three reportable segments as described in Note 1.

Each segment assumes responsibility for its operating results to operating income (loss). Generation expenses include Energy Trading's intersegment charge for energy marketing. 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 2. 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, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**2,259**	**3**	**–**	**2,262**
Fuel and purchased power	**809**	**–**	**–**	**809**
Gross margin	**1,450**	**3**	**–**	**1,453**
Operations, maintenance, and administration	**384**	**28**	**81**	**493**
Depreciation and amortization	**489**	**–**	**20**	**509**
Asset impairment charges	**324**	**–**	**–**	**324**
Inventory writedown	**44**	**–**	**–**	**44**
Restructuring charges	**5**	**–**	**8**	**13**
Taxes, other than income taxes	**27**	**–**	**1**	**28**
Intersegment cost allocation	**13**	**(13)**	**–**	**–**
Operating income (loss)	**164**	**(12)**	**(110)**	**42**
Finance lease income	**16**	**–**	**–**	**16**
Equity loss	**(15)**	**–**	**–**	**(15)**
Sundance Units 1 and 2 arbitration	**(254)**	**–**	**–**	**(254)**
Gain on sale of assets	**3**	**–**	**–**	**3**
Gain on sale of collateral	**–**	**15**	**–**	**15**
Other income				**1**
Foreign exchange loss				**(9)**
Net interest expense				**(242)**
Loss before income taxes				**(443)**

Year ended Dec. 31, 2011	Generation	Energy Trading	Corporate	Total
Revenues	2,526	137	–	2,663
Fuel and purchased power	947	–	–	947
Gross margin	1,579	137	–	1,716
Operations, maintenance, and administration	419	43	83	545
Depreciation and amortization	460	1	21	482
Asset impairment charges	17	–	–	17
Taxes, other than income taxes	27	–	–	27
Intersegment cost allocation	8	(8)	–	–
Operating income (loss)	648	101	(104)	645
Finance lease income	8	–	–	8
Equity income	14	–	–	14
Gain on sale of assets	16	–	–	16
Reserve on collateral	–	(18)	–	(18)
Other income				2
Foreign exchange loss				(3)
Net interest expense				(215)
Earnings before income taxes				449

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Revenues	2,632	41	–	2,673
Fuel and purchased power	1,185	–	–	1,185
Gross margin	1,447	41	–	1,488
Operations, maintenance, and administration	424	17	69	510
Depreciation and amortization	443	2	19	464
Asset impairment charges	28	–	–	28
Taxes, other than income taxes	27	–	–	27
Intersegment cost allocation	5	(5)	–	–
Operating income	520	27	(88)	459
Finance lease income	8	–	–	8
Equity income	7	–	–	7
Foreign exchange gain				8
Net interest expense				(178)
Earnings before income taxes				304

Included in the Generation Segment's results is $23 million (2011 – $24 million, 2010 – $18 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2012	**Generation**[1]	**Energy Trading**	**Corporate**	**Total**
Goodwill *(Note 22)*	**417**	**30**	**–**	**447**
Total segment assets	**8,983**	**262**	**206**	**9,451**

1 Total Generation Segment assets includes $172 million related to investments in joint ventures accounted for by the equity method.

As at Dec. 31, 2011	Generation[2]	Energy Trading	Corporate	Total
Goodwill *(Note 22)*	417	30	–	447
Total segment assets	8,983	394	352	9,729

2 Total Generation Segment assets includes $193 million related to investments in joint ventures accounted for by the equity method.

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment	**684**	**–**	**19**	**703**
Intangible assets	**7**	**1**	**31**	**39**

Year ended Dec. 31, 2011	Generation	Energy Trading	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	445	–	8	453
Intangible assets	7	1	22	30

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	803	–	5	808
Intangible assets	11	2	16	29

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

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

Year ended Dec. 31	2012	2011	2010
Depreciation and amortization expense on the Consolidated Statements of Earnings	**509**	482	464
Depreciation included in fuel and purchased power *(Note 8)*	**41**	40	37
Other	**14**	10	10
Depreciation and amortization on the Consolidated Statements of Cash Flows	**564**	532	511

C. Geographic Information

I. Revenues

Year ended Dec. 31	2012	2011	2010
Canada	**1,841**	1,871	1,754
U.S.	**300**	674	815
Australia	**121**	118	104
Total revenue	**2,262**	2,663	2,673

II. Non-Current Assets

	Property, plant, and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	2012	2011	2012	2011	2012	2011	2012	2011
Canada	**6,437**	6,282	**276**	267	**59**	52	**417**	417
U.S.	**443**	831	**4**	5	**8**	13	**30**	30
Australia	**164**	158	**4**	4	**23**	25	**–**	–
Total	**7,044**	7,271	**284**	276	**90**	90	**447**	447