TRANSALTA CORPORATION

2012 RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

March 1, 2012

TABLE OF CONTENTS

PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form ("Annual Information Form" or "AIF") is given as at or for the year ended December 31, 2011. On January 1, 2011, we adopted International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises. Prior to the adoption of IFRS, we followed Canadian Generally Accepted Accounting Principles ("Canadian GAAP" or "our previous GAAP"). All dollar amounts are in Canadian dollars unless otherwise noted. Unless the context otherwise requires, all references to the "Corporation" and to "TransAlta", "we", "our" and "us" herein refer to TransAlta Corporation and its subsidiaries on a consolidated basis. References to "TransAlta Corporation" herein refer to TransAlta Corporation, excluding its subsidiaries**.**

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

In particular, this Annual Information Form contains forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates, and their attendant costs; expectations related to future earnings and cash flow from operating activities; estimates of fuel supply and demand conditions and the costs of procuring fuel; our estimated spend on growth and sustaining capital projects; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; expectations for the outcome of existing or potential legal and contractual claims; expectations for the ability to access capital markets at reasonable terms; the impact of certain hedges on future reported earnings; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar; and the monitoring of our exposure to liquidity risk.

Factors that may adversely impact our forward looking statements include risks relating to: fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; the regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; effects of weather; disruptions in the source of fuels, water or wind required to operate our facilities; natural disasters; the threat of domestic terrorism and cyber-attacks; equipment failure; energy trading risks; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal proceedings involving the Corporation; reliance on key personnel; labour relations matters; and development projects and acquisitions. Certain risk factors are described in further detail under the heading "Risk Factors" in this Annual Information Form and in the documents incorporated by reference in this Annual Information Form, including our Management's Discussion and Analysis for the year ended December 31, 2011 (the "Annual MD&A").

Readers are urged to consider these factors carefully in evaluating the forward looking statements and are cautioned not to place undue reliance on these forward looking statements. The forward looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks,

uncertainties and assumptions, the forward looking events might occur to a different extent or at a different time than we have described or might not occur. We cannot assure that projected results or events will be achieved.

DOCUMENTS INCORPORATED BY REFERENCE

TransAlta's audited consolidated financial statements for the year ended December 31, 2011 and related Annual MD&A are hereby specifically incorporated by reference in this AIF. Copies of these documents are available on SEDAR at www.sedar.com.

CORPORATE STRUCTURE

Name and Incorporation

TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* (the "CBCA") on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving TransAlta Corporation and TransAlta Utilities Corporation ("TransAlta Utilities" or "TAU") under the CBCA. The plan of arrangement, which was approved by shareholders on November 26, 1992, resulted in common shareholders of TransAlta Utilities exchanging their common shares for shares of TransAlta Corporation on a one for one basis. Upon completion of the arrangement, TransAlta Utilities became a wholly owned subsidiary of TransAlta Corporation.

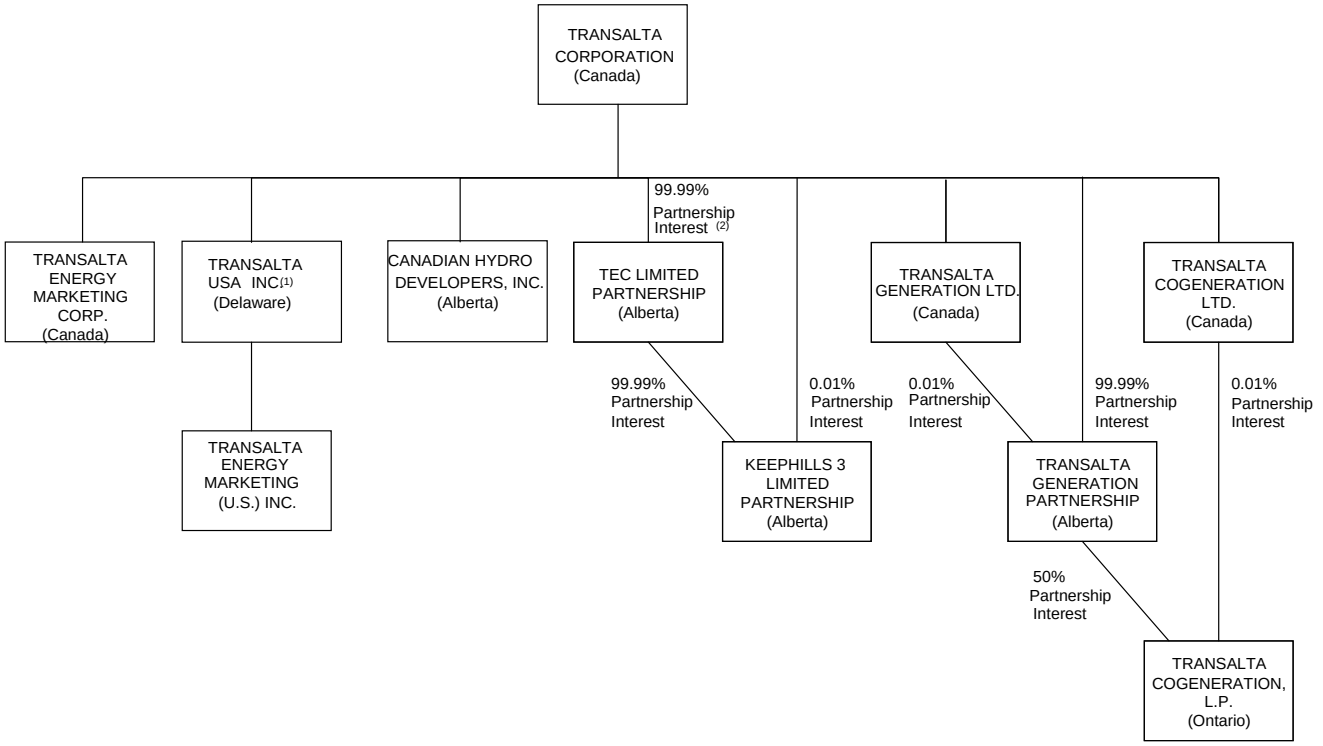
Effective January 1, 2009, TransAlta completed a reorganization (the "Reorganization'), whereby the assets and business affairs of TAU and TransAlta Energy Corporation ("TransAlta Energy" or "TEC") (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta Corporation and TransAlta Generation Ltd., a wholly owned subsidiary of TransAlta Corporation. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of the partnership agreement and a management services agreement.

Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the CBCA. TransAlta Corporation remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of certain wind assets, and some of which are now held indirectly, in the case of both the former generation assets and businesses of TAU and TEC and the assets and business of Canadian Hydro Developers, Inc. ("Canadian Hydro"). TransAlta completed its acquisition of Canadian Hydro on November 4, 2009.

TransAlta amended its articles on December 7, 2010 to create its First Preferred Series A and B shares and again on November 23, 2011 with respect to the creation of the First Preferred Series C and D shares.

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

As of December 31, 2011, the principal subsidiaries of TransAlta Corporation and their respective jurisdictions of formation are set out below:



Notes:

(1) TransAlta USA Inc. is an indirect subsidiary of TransAlta Corporation.

(2) The remaining 0.01 per cent interest in TEC Limited Partnerships is owned by TransAlta (Ft. McMurray) Ltd., a wholly owned subsidiary of TransAlta Corporation.

OVERVIEW

TransAlta and its predecessors have been engaged in the production and sale of electric energy since 1909. We are among Canada's largest non-regulated electricity generation and energy marketing companies with an aggregate net ownership interest of 8,257 megawatts ("MW") of generating capacity[1]. We operate facilities having approximately 10,129 MW of aggregate generating capacity. In addition, we have facilities under construction with a net ownership interest of 129 MW of generating capacity, for total net ownership of 8,386 MW of generating capacity in facilities that have or will have aggregate capacity of 10,258 MW. We are focused on generating electricity in Canada, the United States and Australia through our diversified portfolio of facilities fuelled by coal, natural gas, hydroelectric, wind and geothermal resources. Our fuel diversity protects us from a sudden, unexpected increase in the cost of any one fuel or the unpredictable nature of water flows and wind.

In Canada, we hold a net ownership interest of 6,107 MW of electrical generating capacity in thermal, natural gas-fired, wind powered and hydroelectric facilities, comprised of 4,775 MW in Western Canada, 1,040 MW in Ontario, 167 MW in Québec and 125 MW in New Brunswick.

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

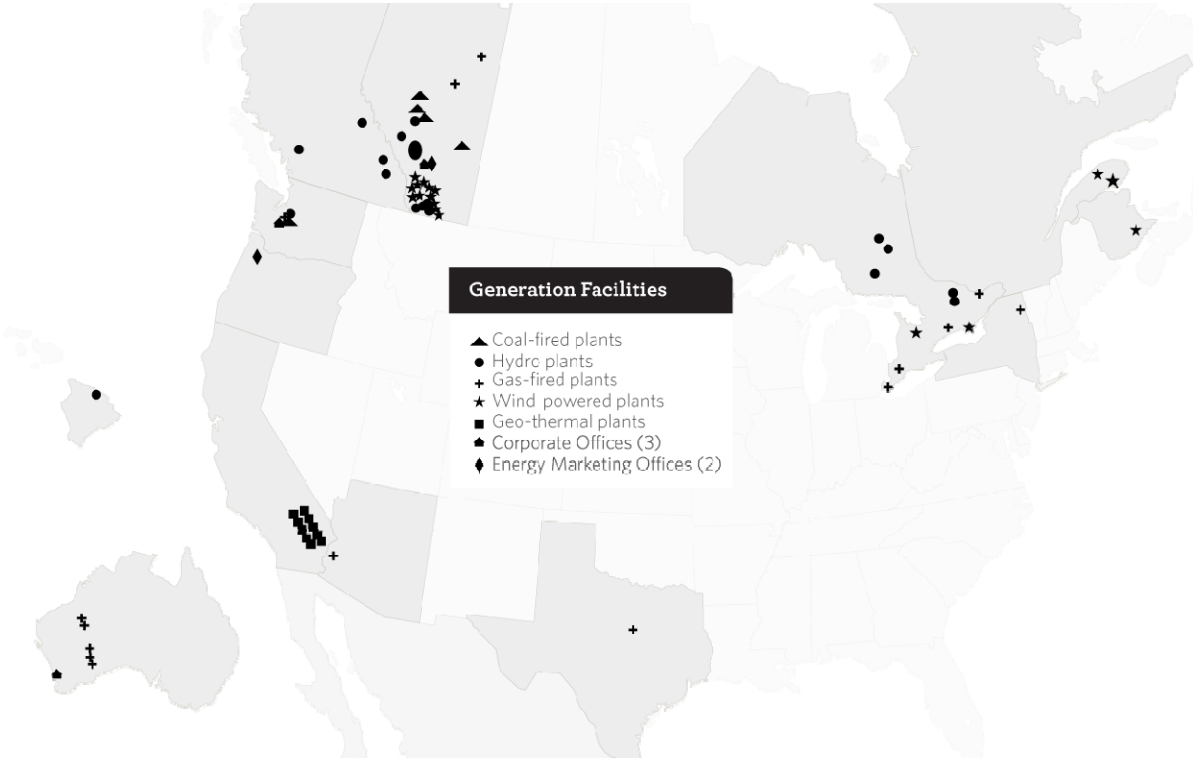
In the United States, our principal facilities include a 1,340 MW thermal facility and a 248 MW natural gas-fired facility, both located in Centralia, Washington, which supply electricity to the Pacific Northwest. We also hold a 50 per cent interest in CE Generation, LLC ("CE Generation"), through which we have an aggregate net ownership interest of approximately 385 MW of generating capacity in geothermal facilities in California and natural gas-fired facilities in Texas, Arizona and New York. In addition, we have 6 MW of electrical generating capacity through hydroelectric facilities located in Washington and Hawaii.

In Australia, we have 300 MW of net electrical generating capacity from natural gas-fired generation facilities that are located at customer mine sites.

We regularly review our operations in order to optimize our generating assets and evaluate appropriate growth opportunities to maximize value to the Corporation. We have in the past and may in the future make changes and additions to our fleet of coal, natural gas, hydro, wind and geothermal fuelled facilities.

TransAlta's Map of Operations

The following map outlines TransAlta's operations as of December 31, 2011.



GENERAL DEVELOPMENT OF THE BUSINESS

TransAlta is organized into three business segments: Generation, Energy Trading[1] and Corporate. The Generation group is responsible for constructing, operating and maintaining our electricity generation facilities. The Energy Trading group is responsible for the wholesale trading of electricity and other energy-related commodities and derivatives. This group also encompasses the management of available generating capacity as well as the fuel and transmission needs of the Generation business. Both segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, procurement, information technology, risk management, human resources, internal audit, and other administrative services, including compliance and governance services.

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

Recent Developments

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

On February 21, 2012, TransAlta Corporation added a Premium Dividend™ Component to its existing Dividend Reinvestment and Share Purchase Plan. The amended and restated plan, the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan provides eligible shareholders of TransAlta with two options: i) to reinvest dividends at a current three per cent discount (may be from zero to five per cent at the discretion of the Board of Directors) to the average market price towards the purchase of new shares of TransAlta (the Dividend Reinvestment Component) or ii) receive the equivalent to 102% of the dividends payable in cash, a premium cash payment (the Premium Dividend™ Component).

Eligible shareholders enrolled in either the Dividend Reinvestment Component or the Premium Dividend™ Component will also be eligible to purchase new shares at a discount to the average market price under the optional cash payment component (the OCP Component) of the plan by directly investing up to $5,000.00 per quarter. The applicable discount under the OCP Component is also determined from time to time by the Board and is currently set at three per cent.

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.

To participate in the plan, eligible shareholders must be resident in Canada. Residents of the United States or an individual who is otherwise a "U.S. Person" under applicable United States securities laws may not participate in the plan. Shareholders who are resident in any jurisdiction outside of Canada (other than the United States) may participate in the plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that TransAlta is satisfied, in its sole discretion, that such laws do not subject the plan, TransAlta, the plan agent or the plan broker to additional legal or regulatory requirements.

President and Chief Executive Officer

On January 2, 2012, Dawn Farrell, was appointed our President and Chief Executive Officer, following the retirement of Steve Snyder on January 1, 2012, as previously announced on July 27, 2011. As of the date of her appointment, Mrs. Farrell was also appointed to the Board of Directors ("Board").

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

Generation and Business Development

2011

MF Global Inc.

In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protections in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. MF Global Inc. has not filed for bankruptcy, but under the U.S. Securities Investor Protection Act, the Securities Investor Protection Corp. is overseeing a liquidation of the broker-dealer to return assets to customers. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of our collateral relates to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and is subject to a dispute between the U.S. trustee and the U.K. administrator. We have collateral of approximately $36 million with MF Global Inc. and due to the uncertainty of collection; we have recognized an $18 million reserve against the collateral that had been posted. The net amount of the collateral has been reclassified to a long-term asset.

Genesee Unit 3 Outage

On November 11, 2011, the Genesee 3 plant, a 466 MW joint venture with Capital Power Corporation ("Capital Power") (233 MW net ownership interest), experienced an unplanned outage that resulted in damage to turbine/generator bearings. Genesee 3 returned to service on January 15, 2012.

Keephills Unit 3

On September 1, 2011, our 450 MW Keephills Unit 3 thermal facility, of which we have a 50 per cent ownership interest, began commercial operations. The total cost of the project was approximately $1.98 billion, our share being 50 per cent.

Sale of Grande Prairie Facility

On July 27, 2011, we signed an agreement to sell our interest in the biomass facility located in Grande Prairie. This transaction closed on October 1, 2011.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at our 353 MW Sundance 3 thermal plant in Wabamun, Alberta due to the mechanical failure of critical generator components. In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed *force majeure* relief under the Sundance B3 Power Purchase Arrangement ("PPA"). Since the event, we have recorded an after-tax charge of $16 million, or 50 per cent of the penalties, as calculated under the PPA, pending a resolution of this matter.

On October 20, 2010, the Balancing Pool of Alberta, an entity established by the Government of Alberta (the "Balancing Pool"), confirmed our determination that the mechanical failure met the requirements of a HILP event under the PPA. Subsequent to this, on July 5, 2011, the Balancing Pool purported to rescind its earlier determination. Neither action is a conclusive finding of a *force majeure* event, nor does either provide a definitive resolution to the dispute. Management continues to be of the view that the event constitutes both a HILP and *force majeure* and that they will be resolved in TransAlta's favour. The arbitration hearing has been set for May 2012. Pending a resolution of this matter, we may be required to pay to the PPA Buyers the penalties as calculated under the PPA and record an additional $16 million charge to earnings. There is no additional impact to earnings at this time as the facility is operating at full capacity. The unit may be operated in that manner for as long as our monitoring indicates that it can be operated safely, subject to the terms of the agreement, market conditions and other operating requirements. The previously announced major maintenance at this facility remains scheduled for the middle of 2012.

Bone Creek

On June 1, 2011, our 19 MW Bone Creek hydro facility began commercial operations. The total capital cost of the project was approximately $52 million.

Centralia Coal

On April 26, 2010, we announced that we signed a memorandum of understanding ("MOU") with the State of Washington to enter discussions to develop an agreement to significantly reduce greenhouse gas ("GHG") emissions from the Centralia Thermal plant, and to provide replacement capacity by 2025. The MOU also recognizes the need to protect the value that Centralia Thermal brings to our shareholders.

On May 6, 2011, Senate Bill 5769 (the "Bill") was signed into law in the State of Washington. The Bill, and a related Memorandum of Agreement (the "MoA") which was signed on December 23, 2011, provide a framework to transition from coal-fired energy produced at our Centralia Coal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of shut-down of the units and the removal of restrictions on the terms of power contracts into which we can enter.

Sale of Meridian

On April 1, 2011, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, closed the sale of its 50 per cent interest in the Meridian facility. The sale was effective as of January 1, 2011.

New Richmond

On March 28, 2011, we announced that we had received approval from the Government of Québec 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 $205 million and commercial operations are expected to commence during the fourth quarter of 2012.

Sundance Unit 1 and Unit 2 Shut Down

In December 2010, Unit 1 and Unit 2 of our Sundance coal-fired generation facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units, with potential production of 4,906 gigawatt hours ("GWh"), was unavailable for year ended December 31, 2011.

We are pursuing all our remedies under the PPA resulting from these events. Firstly, under the terms of the PPA for these units, we notified the PPA Buyer and the Balancing Pool of a *force majeure* event. To the extent the event meets the *force majeure* criteria set out in the PPA, we believe we are entitled to receive our PPA capacity payments and are protected from having to pay penalties for the units' lack of availability and as a result, we do not expect any material adverse effect on our results or operations. Secondly, on February 8, 2011, we issued a notice of termination for destruction on Sundance Units 1 and 2 under the terms of the PPA. This action was based on the determination that the physical state of the boilers was such that the units cannot be economically restored to service under the terms of the PPA. To the extent the event meets the termination for destruction criteria set out in the PPA, we believe we are entitled to recover the net book value specified in the PPA, and as a result, we do not expect any material financial impact.

On February 18, 2011, the PPA Buyer provided notice that it intends to dispute the notice of *force majeure* and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. The binding arbitration process to resolve the dispute is underway. The arbitration panel identified dates in March and April 2012 to hear these claims, and indicated that its decision would be forthcoming in mid-2012. No assurance can be given as to the timing or ultimate outcome of these matters.

2010

Kent Hills 2

On November 21, 2010, the 54 MW expansion of our Kent Hills wind farm, located about 33 kilometers southwest of Moncton, New Brunswick, began commercial operations on budget and ahead of schedule. The expansion increased the existing capacity of the facility to 150 MW. The total cost of the project was approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010.

Ardenville

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

Sundance Unit 3 Uprate

On October 29, 2010, we announced that we are proceeding with the addition of a 15 MW efficiency uprate at Unit 3 of our Sundance facility in Alberta. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Decommisioning of Wabamun Plant

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

Summerview 2

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

2009

Acquisition of Canadian Hydro

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

Blue Trail

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

Sarnia Contract

On September 30, 2009, we entered into a new long-term agreement with the Ontario Power Authority (the "OPA") for our Sarnia regional natural gas cogeneration power plant. The contract is capacity-based and the term of the new agreement runs to December 31, 2025. While the specific terms and conditions of the contract are confidential, the OPA has indicated that the agreement is in line with other similar agreements issued by the OPA.

Major Maintenance Plans

On May 20, 2009, we announced the advancement of a major maintenance outage on our 353 MW Sundance 3 facility from the second quarter of 2010 into the second and third quarters of 2009.

Sundance Unit 4 Derate

On February 10, 2009, we reported that the 406 MW Sundance 4 facility had experienced an unplanned outage in December 2008 relating to the failure of an induced draft fan. At that time, the unit was derated to approximately 205 MW. The repair of the fan components by the original equipment manufacturer took longer than planned and, therefore, Unit 4 did not return to full service until February 23, 2009. As a result of the extended derate, 2009 first quarter production was reduced by 328 gigawatt hour ("GWh"). On April 27, 2009, the Balancing Pool rejected our assertion that this outage should be regarded as a HILP *Force majeure* Event. As required by the PPA legislation, we were required to pay the penalties related to the derate. We settled the issue in the third quarter of 2009 and the terms of the settlement are confidential.

Keephills Unit 1 and 2 Uprates

On January 29, 2009, we announced a 46 MW (23 MW per unit) efficiency uprate at Unit 1 and Unit 2 of our Keephills facility in Alberta. Both Keephills Units 1 and 2 will be upgraded to 406 MW. The total capital cost

of the projects is estimated at $68 million with commercial operations of both units expected by the end of 2012.

Corporate Matters

2011

Sale of Preferred Shares

On November 30, 2011, we issued $275 million principal amount of Series C 4.60 per cent Cumulative Redeemable Rate Reset First Preferred shares, for net proceeds of $267.2 million.

President and Chief Executive Officer and Board of Directors' Changes

On July 27, 2011, we announced that President and Chief Executive Officer Steve Snyder would retire, effective January 1, 2012 and Dawn Farrell, TransAlta's Chief Operating Officer, would succeed Mr. Snyder as President and CEO on January 2, 2012.

On July 18, 2011, Mr. Yakout Mansour was appointed to our Board. Mr. Mansour, a professional engineer and a Fellow of the Institute of Electrical and Electronics Engineers, recently retired from his position as the President and CEO of the California Independent System Operator Corporation.

On February 24, 2011, the Board announced that Ambassador Gordon D. Giffin, subject to his re-election at our Annual Shareholders meeting, would succeed Donna Soble Kaufman, whose two consecutive three-year term limits as Chair were to expire on April 28, 2011.

2010

Sale of Preferred Shares

On December 10, 2010, we issued $300 million principal amount of 4.60 per cent Series A Cumulative Redeemable Rate Reset First Preferred shares for net proceeds of $291.2 million.

Project Pioneer

On October 14, 2009, the federal and provincial governments announced that our CCS project, Project Pioneer, would receive committed funding of more than $750 million. The funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a front-end engineering and design ("FEED") study to determine if the project is viable. The FEED study is expected to cost $20 million: $10 million will come from the federal government; $5 million will come from the provincial government; and $5 million will come from TransAlta and from industry partners Alstom Canada Inc., Capital Power, and Enbridge Inc. Construction of the facility, if supported as expected by the study, would be targeted for start-up in 2015. We are the managing partner of the joint government-industry partnership. Project Pioneer was first announced on April 3, 2008, as an agreement with Alstom Canada to develop the one million tonne/year CCS project at one of TransAlta's coal-fired power stations in Alberta.

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

Environmental Regulation

On June 23, 2010, we responded to the federal government's recent policy announcement mandating the phased end of coal-fired electricity generation in Canada. Under Ottawa's proposal, power companies would have to close their coal-fired facilities at 45 years of age, or the end of their PPAs, whichever is later. Companies would be prohibited from making investments to extend the lives of those plants unless emission levels can be reduced to levels equivalent to those of a natural gas combined-cycle plant.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed Chief Financial Officer, succeeding Brian Burden, who retired from TransAlta. Mr. Burden assisted Mr. Gellner with the transition through September 30, 2010.

Dividend Reinvestment and Share Purchase Plan ("DRASP")

On April 29, 2010, in accordance with the terms of our DRASP plan, the Board approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date.

Senior Notes Offering

On March 12, 2010, we issued US$300 million principal amount of 6.50 per cent senior notes, maturing March 15, 2040, for net proceeds of US$293.3 million.

2009

Medium-Term Notes Offerings

On November 18, 2009, we issued $400 million principal amount of 6.4 per cent medium term notes, maturing November 18, 2019 for net proceeds of $397.2 million.

On May 29, 2009, we issued $200 million principal amount of 6.45 per cent medium term notes, maturing May 29, 2014 for net proceeds of $198.9 million.

Senior Notes Offerings

On November 13, 2009, we issued US$500 million principal amount of 4.75 per cent senior notes, maturing January 15, 2015 for net proceeds of US$495.9 million.

Sale of Common Shares

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

Increase in Quarterly Dividend

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

BUSINESS OF TRANSALTA

Generation Business Segment

Our Generation business segment is responsible for constructing, operating and maintaining our electricity generation facilities. The following table summarizes our generation facilities which are operating, under construction or under development, as at December 31, 2011. Subsequent sections provide more detailed information on facilities by geographic location and fuel type.

Western Canada						
Facility	**Gross Capacity (MW)** [1]	**Ownership (%)**	**Net Capacity Ownership Interest** [1]	**Fuel**	**Revenue Source**	**Contract Expiry Date**
Sundance [2][3]	1,581	100	1,581	Coal	Alberta PPA / Merchant[3]	2020
Keephills [4]	812	100	812	Coal	Alberta PPA/Merchant[4]	2020
Keephills 3	450	50	225	Coal	Merchant	-
Sheerness	780	25	195	Coal	Alberta PPA	2020
Genesee 3	466	50	233	Coal	Merchant	-
Fort Saskatchewan	118	30	35	Natural gas	Long-term contract ("LTC")	2019
Poplar Creek	356	100	356	Natural gas	LTC/Merchant	2024
Blue Trail	66	100	66	Wind	Merchant	-
Castle River [5]	44	100	44	Wind	LTC/Merchant	2011
Cowley North	20	100	20	Wind	Merchant	-
Cowley Ridge	21	100	21	Wind	Merchant	-
Macleod Flats	3	100	3	Wind	Merchant	-
McBride Lake	75	50	38	Wind	LTC	2023
Sinnott	7	100	7	Wind	Merchant	-
Soderglen	71	50	35	Wind	Merchant	-
Summerview 1 [6]	70	100	70	Wind	Merchant	-
Summerview 2	66	100	66	Wind	Merchant	-
Ardenville	69	100	69	Wind	Merchant	-
Akolkolex	10	100	10	Hydro	LTC	2015
Barrier	13	100	13	Hydro	Alberta PPA	2020
Bearspaw	17	100	17	Hydro	Alberta PPA	2020
Belly River	3	100	3	Hydro	Merchant	-
Big Horn	120	100	120	Hydro	Alberta PPA	2020
Bone Creek	19	100	19	Hydro	LTC	2031
Brazeau	355	100	355	Hydro	Alberta PPA	2020
Cascade	36	100	36	Hydro	Alberta PPA	2020
Ghost	51	100	51	Hydro	Alberta PPA	2020
Horseshoe	14	100	14	Hydro	Alberta PPA	2020
Interlakes	5	100	5	Hydro	Alberta PPA	2020
Kananaskis	19	100	19	Hydro	Alberta PPA	2020
Pingston	45	50	23	Hydro	LTC	2023
Pocaterra	15	100	15	Hydro	Alberta PPA	2013
Rundle	50	100	50	Hydro	Alberta PPA	2020
Spray	103	100	103	Hydro	Alberta PPA	2020
St. Mary	2	100	2	Hydro	Merchant	-
Taylor Hydro	13	100	13	Hydro	Merchant	-
Three Sisters	3	100	3	Hydro	Alberta PPA	2020
Upper Mamquam	25	100	25	Hydro	LTC	2025
Waterton	3	100	3	Hydro	Merchant	-
Total Western Canada	**5,996**		**4,775**			

Eastern Canada

Facility	Gross Capacity (MW) [1]	Ownership (%)	Net Capacity Ownership Interest [1]	Fuel	Revenue Source	Contract Expiry Date
Mississauga	108	50	54	Natural gas	LTC	2018
Ottawa	68	50	34	Natural gas	LTC	2013
Sarnia [7]	506	100	506	Natural gas	LTC	2022-2025
Windsor	68	50	34	Natural gas	LTC/Merchant	2016
Kent Hills	150	83	125	Wind	LTC	2033-2035
Le Nordais	99	100	99	Wind	LTC	2033
New Richmond [8]	68	100	68	Wind	LTC	2031
Melancthon	200	100	200	Wind	LTC	2026-2028
Wolfe Island	198	100	198	Wind	LTC	2029
Appleton	1	100	1	Hydro	LTC	2030
Galetta	2	100	2	Hydro	LTC	2030
Misema	3	100	3	Hydro	LTC	2027
Moose Rapids	1	100	1	Hydro	LTC	2030
Ragged Chute	7	100	7	Hydro	Merchant	-
Total Eastern Canada	**1,479**		**1,332**			

US

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

Australia

Facility	Gross Capacity (MW) [1]	Ownership (%)	Net Capacity Ownership Interest [1]	Fuel	Revenue Source	Contract Expiry Date
Parkeston	110	50	55	Natural gas	LTC	2016
Southern Cross[12]	245	100	245	Natural gas/Diesel	LTC	2013
Total Australia	**355**		**300**			
TOTAL	**10,258**		**8,386**			

Notes:

(1) MW are rounded to the nearest whole number. Capacity includes all generating assets (generation operations, finance lease, and equity investments).

(2) Please refer to Generation and Business Developments in this AIF for information with respect to the destruction of our Sundance 1 and 2 units.

(3) Capacity refers to 15 MW (under development), 53 MW, 53 MW and 44 MW uprates on units 3, 4, 5 and 6, respectively.

(4) Capacity includes two 23 MW uprates on units 1 and 2, both expected to be commercial in 2012.

(5) Includes seven additional turbines at other locations.

(6) Comprised of two facilities.

(7) Sarnia's NMC has been adjusted from 575 MW due to decommissioning of equipment at the facility.

(8) This facility is currently under development.

(9) Centralia Thermal's NMC has been reduced from 1,404 MW to reflect a lower plant output as a result of its conversion to burning Powder River Basin coal.
(10) Comprised of ten facilities.
(11) This facility is used to provide a reliable water supply to our other generation facilities at Centralia.
(12) Comprised of four facilities.

Canada: Western Canada

Thermal Facilities

The following table summarizes our Western Canadian thermal generation facilities:

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Sundance [1]	AB	Sundance Unit No. 3[2]	368	100	1976	2020
	AB	Sundance Unit No. 4	406	100	1977	2020
	AB	Sundance Unit No. 5	406	100	1978	2020
	AB	Sundance Unit No. 6	401	100	1980	2020
Keephills	AB	Keephills Unit No. 1[3]	406	100	1983	2020
	AB	Keephills Unit No. 2[3]	406	100	1984	2020
	AB	Keephills Unit No. 3	450	50	2011	-
Sheerness	AB	Sheerness Unit No. 1	390	25	1986	2020
	AB	Sheerness Unit No. 2	390	25	1990	2020
Genesee	AB	Genesee 3	466	50	2005	-
Total			**4,089**			

Notes:
(1) Please refer to Generation and Business Developments in this AIF for information with respect to the destruction of our Sundance 1 and 2 units.
(2) Includes a 15 MW uprate expected to be commercial in 2012.
(3) Includes two 23 MW uprates on units 1 and 2, both expected to be commercial in 2012.

The Sundance and Keephills facilities are located approximately 70 kilometres west of Edmonton, Alberta, both of which are owned by TransAlta. The Sheerness facility is located approximately 200 kilometres northeast of Calgary, Alberta and is jointly owned by TA Cogen, an Ontario limited partnership, and ATCO Power (2000) Ltd. ("ATCO Power"). The Genesee facility is located approximately 70 kilometres west of Edmonton, Alberta, which we jointly own with Capital Power. Our thermal plants are generally base load plants, meaning that they are expected to operate for long periods of time at or near their rated capacity.

Fuel requirements for our Western Canadian thermal power facilities are supplied by a surface strip coal mine located in close proximity to the facilities. We own the Highvale mine that supplies coal to the Sundance and Keephills facilities; however, TransAlta has contracted Prairie Mines & Royalties Limited ("PMRL") to perform the mining, reclamation and associated work at the Highvale mine. We estimate that the recoverable coal reserves contained in this mine are expected to be sufficient to supply the anticipated requirements for the life of the facilities which it serves, including running post PPA expiry and potential plant expansion. We also own the Whitewood mine, which formerly supplied coal to the now decommissioned Wabamum facility. The Whitewood mine is no longer in operation, and we have completed reclamation of the site as required by Alberta Environment.

Coal for the Sheerness facility is provided from the adjacent Sheerness mine. The coal reserves of the mine are owned, leased or controlled jointly by TA Cogen, ATCO Power and PMRL. TA Cogen and ATCO Power have entered into coal supply agreements with PMRL, which operates the mine, to supply coal until 2026.

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

Construction on the Keephills 3 power project started on February 26, 2007. Through Keephills 3 Limited Partnership ("K3LP"), TransAlta and Capital Power are equal partners in the ownership of Keephills 3, with Capital Power having been responsible for construction and TransAlta responsible for managing the joint venture. Keephills 3 began commercial operations on September 1, 2011. The facility is jointly operated by TransAlta and Capital Power. Each partner independently dispatches and markets its share of the unit's electrical output. We provide the coal fuel to the facility through our Highvale mine.

Natural Gas-Fired Facilities

The following table summarizes our Western Canadian natural gas-fired generation facilities:

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Fort Saskatchewan [(1)]	AB	Fort Saskatchewan	118	30	1999	2019
Fort McMurray	AB	Poplar Creek	356	100	2001	2024
Total			**474**			

Note:

(1) Under IFRS, our interest in the Fort Saskatchewan facility is accounted for as a finance lease. Under Canadian GAAP, we previously proportionately consolidated our interest in the Fort Saskatchewan facility.

Our interest in the Fort Saskatchewan facility is held through TA Cogen. See "TA Cogen" later in this AIF. The 118 MW natural gas-fired combined-cycle cogeneration Fort Saskatchewan plant is located in Fort Saskatchewan, Alberta and is owned by TA Cogen and Strongwater Energy Ltd., providing electricity and steam to Dow Chemical Canada Inc. under the terms of a long-term contract which expires in 2019.

Our Poplar Creek plant is located in Fort McMurray, Alberta. We operate this 356 MW cogeneration plant which became fully operational in the first quarter of 2001 and delivers approximately 150 MW of electricity and steam to Suncor Energy Inc. ("Suncor") under the terms of a long-term contract which expires in 2024. Any surplus power not used by Suncor is available to us to sell to other parties, in which case Suncor is entitled to share in the revenue, under certain conditions.

Hydroelectric Facilities

The following table summarizes our Western Canadian hydroelectric facilities:

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Akolkolex River System[2]	BC	Akolkolex	10	100	1995	2015
	BC	Pingston	45	50	2003, 2004	2023
Mamquam River System[2]	BC	Upper Mamquam	25	100	2005	2025
Thompson River System	BC	Bone Creek	19	100	2011	2031
Bow River System	AB	Barrier	13	100	1947	2020
	AB	Bearspaw	17	100	1954	2020
	AB	Cascade	36	100	1942, 1957	2020
	AB	Ghost	51	100	1929, 1954	2020
	AB	Horseshoe	14	100	1911	2020
	AB	Interlakes	5	100	1955	2020
	AB	Kananaskis	19	100	1913, 1951	2020
	AB	Pocaterra	15	100	1955	2013
	AB	Rundle	50	100	1951, 1960	2020
	AB	Spray	103	100	1951, 1960	2020
	AB	Three Sisters	3	100	1951	2020
North Sask. River System	AB	Bighorn	120	100	1972	2020
	AB	Brazeau	355	100	1965, 1967	2020
Oldman River System	AB	Belly River	3	100	1991	-
	AB	St. Mary	2	100	1992	-
	AB	Taylor Hydro	13	100	2000	-
	AB	Waterton	3	100	1992	-
Total			**921**			

Notes:
(1) MW are rounded to the nearest whole number.
(2) These facilities are EcoPower® registered.

Akolkolex River System

Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW located on the Akolkolex River, south of Revelstoke, British Columbia. We own 100 per cent of this facility. It has been operating since 1995. The output from the facility is sold to BC Hydro.

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

Mamquam River System

Upper Mamquam is a run-of-river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver. We own 100 per cent of this facility. It has been operating since 2005. The output from the facility is sold to BC Hydro.

Thompson River System

Bone Creek is a run-of-river hydroelectric facility with installed capacity of 19 MW located on Bone Creek, 90 kilometres south of the town of Valemount, British Columbia, and we own 100 per cent of this facility. Bone Creek commenced commercial operations on June 1, 2011. The output from the facility is under contract with BC Hydro. The

facility also qualifies for payments of $10/MWh until 2020 from Natural Resources Canada ("NRCan"), a division of the federal government, through the ecoEnergy for Renewable Power ("eERP") program.

Bow River System

Barrier is a run-of-river hydroelectric facility with installed capacity of 13 MW located in Seebe, Alberta. We own 100 per cent of this facility. It has been operating since 1947. The facility operates under an Alberta PPA.

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. We own 100 per cent of this facility. It has been operating since 1954. The facility operates under an Alberta PPA.

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. We own 100 per cent of this facility, having purchased it from the Government of Canada in 1941. The following year, we built a new dam and power plant to replace the original, and then, in 1957, added a second generating unit. The facility operates under an Alberta PPA.

Ghost is a hydroelectric facility with installed capacity of 51 MW located on the Bow River in Cochrane, Alberta. We own 100 per cent of this facility. It has been operating since 1929. The facility operates under an Alberta PPA.

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located in Seebe, Alberta. We own 100 per cent of this facility. It has been operating since 1911. The facility operates under an Alberta PPA.

Interlakes is a hydroelectric facility with installed capacity of 5 MW located in Kananaskis, Alberta. We own 100 per cent of this facility. It has been operating since 1955. The facility operates under an Alberta PPA.

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located in Seebe, Alberta. We own 100 per cent of this facility. It has been operating since 1913. It was expanded in 1951 and modified in 1994. The facility operates under an Alberta PPA.

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located in Kananaskis, Alberta. We own 100 per cent of this facility. It has been operating since 1955. The facility operates under an Alberta PPA, expiring in 2013, at which time the generation from this facility will be sold into the Alberta spot market.

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. We own 100 per cent of this facility. It has been operating since 1951. The facility operates under an Alberta PPA.

Spray is a hydroelectric facility with installed capacity of 103 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. We own 100 per cent of this facility. It has been operating since 1951. The facility operates under an Alberta PPA.

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. We own 100 per cent of this facility. It has been operating since 1951. The facility operates under an Alberta PPA.

North Saskatchewan River System

Bighorn is a hydroelectric facility with installed capacity of 120 MW located in Nordegg, Alberta. We own 100 per cent of this facility. It has been operating since 1972. The facility operates under an Alberta PPA.

Brazeau is a hydroelectric facility with installed capacity of 355 MW located in Drayton Valley, Alberta. We own 100 per cent of this facility. It has been operating since 1965. The facility operates under an Alberta PPA.

Oldman River System

Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in Southern Alberta. Due to its location, along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. We own 100 per cent of this facility. It has been operating since March 1991. Generation from the facility is sold in the Alberta spot market.

St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the St. Mary Dam on the Waterton Reservoir, near Magrath, in Southern Alberta. We own 100 per cent of this facility. It has been operating since December 1992. Generation from the facility is sold in the Alberta spot market.

The Taylor hydroelectric facility ("Taylor Hydro") is a run-of-river facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System which is owned by the Government of Alberta. We own 100 per cent of this facility. It has been operating since May 2000. Generation from the facility is sold in the Alberta spot market.

Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hillspring, southwest of Lethbridge, Alberta. We own 100 per cent of this facility. It has been operating since November 1992. Generation from the facility is sold in the Alberta spot market.

Wind Generation Facilities

We own and operate approximately 992 MW of net wind generation capacity in eleven wind farms in western Canada, three in Ontario, one in Québec and two in New Brunswick. We also have the 68 MW New Richmond wind project in Québec under construction.

Wind is not generally a dispatchable fuel; therefore, in merchant markets, wind assets may not be able to secure the annual average pool price. As such, we make different assumptions in forecast revenue received for generation from a wind asset compared to a base load asset. If these price assumption and generation production forecasts are not correct, the corresponding revenue received may be reduced. Generation production forecasts are based on the long-term average production forecast for a site, reflecting historical forty-year average climatic conditions. Within any year there may be variations from this long-term average. In order to forecast generation production, a number of factors have to be assumed based on historic on-site data and wind farm design including wake and array losses, wind shear and the electrical losses within the site. If these assumptions are incorrect then actual production will be higher or lower than the long-term forecast for the site.

As well as contracting for power, we enter into long-term and short-term contracts to sell the environmental attributes from our merchant wind and hydro facilities. These activities help to ensure earnings consistency from these assets. For 2012, we have sold approximately 75 per cent of the environmental attributes from our merchant wind facilities and 93 per cent of the environmental attributes from our merchant hydro facilities. Generally, for facilities under long-term contract, the benefit of the environmental attributes generated flow through to the contract holder.

The following table summarizes our Western Canadian wind generation facilities:

Location	Province	Plant	Capacity (MW)[1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Fort Macleod	AB	Ardenville	69	100	2010	-
Fort Macleod	AB	Blue Trail	66	100	2009	-
Fort Macleod	AB	McBride Lake	75	50	2003	2023
Fort Macleod	AB	Macleod Flats	3	100	2004	-
Fort Macleod	AB	Soderglen	71	50	2006	-
Pincher Creek	AB	Castle River	44	100	1997-2001	2011
Pincher Creek	AB	Cowley Ridge	21	100	1993	-
Pincher Creek	AB	Cowley North	20	100	2001	-
Pincher Creek	AB	Sinnott	7	100	2001	-
Pincher Creek	AB	Summerview 1	70	100	2004	-
Pincher Creek	AB	Summerview 2	66	100	2010	-
Total			**512**			

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

Ardenville is a 69 MW wind farm and is located approximately eight kilometres south of Fort Macleod, Alberta adjacent to the Macleod Flats wind facility. We constructed the project, which commenced commercial operations on November 10, 2010. The output from this facility is sold in the Alberta spot market. The Ardenville wind farm is entitled to receive payments of $10/MWh until 2020 from NRCan, through the eERP program.

Blue Trail is a 66 MW wind farm located in southern Alberta which commenced commercial operations in November 2009. The total capital cost for this wind power project was $115 million. The output from this facility is sold on the Alberta Power Pool. The Blue Trail wind farm is entitled to receive payments of $10/MWh until 2019 from NRCan, through the eERP program.

McBride Lake is a 75 MW wind farm located at Fort Macleod, Alberta. We constructed the wind farm, and it has been producing electricity since the third quarter of 2003. McBride Lake is operated by us and is equally owned with ENMAX Green Power Inc. The output from the facility is 100 per cent contracted in the form of a 20-year LTC with ENMAX Energy Corp. We are also entitled to receive Wind Power Production Incentive ("WPPI") payments from the federal government at $12/MWh in respect of the McBride Lake facility until 2013. We also own the 0.7 MW McBride Lake East facility in the same vicinity.

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

Soderglen is a 71 MW facility located in southern Alberta, southwest of Fort Macleod and 40 kilometres from our wind operations near Pincher Creek. We share equal ownership of this facility with Nexen Inc. The facility began commercial operations in September 2006. The output from this facility is sold in the Alberta spot market. Soderglen is entitled to receive WPPI payments from the federal government at $10/MWh.

Castle River is a 40 MW wind farm located in Pincher Creek, Alberta. We also own and operate seven additional turbines totalling 4 MW located individually in the Cardston County and Hillspring areas of southwestern Alberta.

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

Cowley North is a 20 MW wind farm, located adjacent to Cowley Ridge. It commenced commercial operations in the fall of 2001. We own this facility, and the output from it is sold in the Alberta spot market.

Sinnott has a total installed capacity of 7 MW and is located directly east of Cowley Ridge. It also commenced commercial operations in the fall of 2001. We own this facility, and the output from it is sold in the Alberta spot market.

Summerview is a 68 MW wind farm comprised of 38-1.8MW turbines and is located approximately 15 kilometres northeast of Pincher Creek, Alberta. We constructed Summerview and it commenced commercial operations in 2004. The Summerview facility, together with an existing 1.8 MW turbine in the area, brings the total wind generation capacity at that location to 70 MW. The Summerview wind farm is a merchant facility but is entitled to receive WPPI payments from the federal government at $10/MWh until 2014.

Summerview 2 is a 66 MW wind farm comprised of 22 Vestas V90-3.0MW wind turbines and is located northeast of Pincher Creek, Alberta. We constructed the facility, which began commercial operations on February 23, 2010. The output is sold in the Alberta spot market. The Summerview 2 wind farm expansion is entitled to receive payments of $10/MWh until 2020 from NRCan, through the eERP program.

During 2011, we decommissioned our Taylor wind facility, a 3 MW facility located in Pincher Creek, Alberta.

Alberta PPAs

All of our Alberta thermal and hydroelectric facilities, other than the Keephills 3, Genesee 3, Belly River, Waterton, St. Mary and Taylor facilities, and uprated capacity, operate under Alberta PPAs. The Alberta PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each thermal plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which electricity is to be supplied. We bear the risk or retain the benefit of volume variances (except for those arising from events considered to be *force majeure*, in the case of the PPA thermal plants) and any change in costs (unless due to a change in law) required to maintain and operate the facilities.

We operate our thermal facilities as base load facilities, which are, however, cycled or dispatched by the PPA Buyers. Under the Alberta PPAs, we are exposed to electricity price risk if availability declines below contracted levels (other than as a result of outages caused by an event of *force majeure*). In those circumstances, we must pay a penalty for the lost availability based upon a price equal to the 30 day rolling average of Alberta's market electricity prices. This rolling average provision attempts to mitigate price spikes that can occur as a result of sudden outages. We attempt to further mitigate this exposure by maintaining contracted and uncontracted capacity in the market, through operation and maintenance practices, and hedging activities.

Our hydroelectric facilities, other than Belly River, St. Mary, Taylor Hydro and Waterton are aggregated through one Alberta PPA which provides for financial obligations for energy and ancillary services based on hourly targets. We meet these targeted amounts through physical delivery or third party purchases.

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

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

The expiry dates for our Alberta PPAs range from 2013 to 2020. We are evaluating the economics of running assets post PPA expiry, in conjunction with expected provincial and federal GHG and other environmental legislation. Upon the expiry of the PPAs, and subject to any legislative limitations, which are addressed below, and our ability to procure an

extension to the operating licenses, if required, we will then be in a position to sell our electricity to the Alberta Power Pool and to third party purchasers through direct sales agreements.

The Alberta PPAs (together with legislation which applies thereto) permit the Balancing Pool, directly or indirectly as successor to the power purchaser under the Alberta PPAs, to terminate the Alberta PPAs in certain circumstances. If the Balancing Pool exercises its ability to terminate, we will, in those circumstances, be entitled to receive a lump-sum payment in connection with such termination.

In June of 2010, the Government of Canada proposed a new regulation to deal with emissions from Canada's fleet of coal-fired power plants. Under Ottawa's proposal, at 45 years of age each coal-fired generating unit would have to meet a new emissions-performance standard or cease operations. The emissions standard for coal-fired facilities is expected to be equivalent to the emission performance of a combined-cycle natural gas power plant. If the proposed regulation comes into effect, our coal-fired plants would be affected if they cannot meet the standard of a combined-cycle natural gas power plant.

Canada: Eastern Canada

Natural Gas-Fired Facilities

Our Ontario natural gas-fired generating facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Sarnia	ON	Sarnia	506	100	2003	2022-2025
Mississauga	ON	Mississauga [(1)]	108	50	1992	2018
Ottawa	ON	Ottawa [(1)]	68	50	1992	2013
Windsor	ON	Windsor [(1)]	68	50	1996	2016
Total			**750**			

Note:
(1) We have a 50 per cent interest in these three facilities through our ownership interest in TA Cogen.

The Sarnia plant is a 506 MW combined-cycle cogeneration facility that provides steam and electricity to nearby industrial facilities owned by LANXESS (formerly Bayer Inc.), Nova Chemicals (Canada) Ltd. (which in turn supplies Styrolution, a Styrene production facility formerly owned by NOVA) and Suncor Energy Products Inc. We own 100 per cent of this facility. On February 15, 2006, we signed a five-year agreement with the OPA for generation from our Sarnia facility. Subsequently, the Ontario Minister of Energy and Infrastructure directed the OPA to seek contracts with us and certain other "Early Movers" to obtain terms and conditions which were more in keeping with the contracts it was offering new facilities. In September 2009, we signed a new contract with the OPA, effective as of July 1, 2009 and terminating on December 31, 2025, which provides more favourable terms than those previously held by the facility. In addition, the new agreement brings the combined total term contracted with the OPA to 20 years and includes provisions for the parties to share in the impact and benefit of changes in customer steam load or loss of steam customer.

The Mississauga plant is owned by TA Cogen. It is a combined-cycle cogeneration facility designed to produce 108 MW of electrical energy. This capacity is contracted under a long-term contract with the Ontario Electricity Financial Corporation ("OEFC") which expires in 2018. Prior to July 2005, the Mississauga plant also provided cogeneration services to Boeing Canada Inc. ("Boeing"). Boeing exercised its right under the cogeneration services agreement to no longer take and pay for cogeneration services due to the closure of its manufacturing facility. Boeing remains entitled to any steam credits which are based on the total plant electricity generation revenue. On or prior to each of January 1, 2013, 2018 and 2023, Boeing may give notice of its intention to continue to purchase or discontinue cogeneration services. In addition, on those same dates, Boeing has the option to require the removal of the Mississauga plant from the leased lands or purchase the Mississauga plant at its net salvage value. Boeing is, however, incented to run the lease to term in 2028 by the annual steam credit payment it receives.

The Ottawa plant is owned by TA Cogen. It is a combined-cycle cogeneration facility designed to produce 68 MW of electrical energy. The capacity is sold under a long-term contract with the OEFC, an agency of the Province of Ontario. The agreement expires in 2013. Negotiations are underway with the OPA to enter into a long-term contract commencing in 2014. The Ottawa plant also provides thermal energy to the member hospitals and treatment centers of the Ottawa Health Sciences Centre, National Defence Medical Centre and the Perley and Rideau Veterans' Health Centre. The thermal energy contracts with the above-named member hospitals and treatment centres all have varying expiry dates, which are as follows: the Ottawa Health Sciences Centre contract expires on December 31, 2022; the National Defence Medical Centre contract expires on December 31, 2017, and the Perley and Rideau Veterans' Health Centre contract expires December 31, 2012.

The Windsor plant is owned by TA Cogen. It is a combined-cycle cogeneration facility designed to produce 68 MW of electrical energy. Currently, 50 MW of the capacity is sold under a long-term contract to the OEFC. This agreement expires in 2016. The Windsor plant also provides thermal energy to Chrysler Canada Inc.'s minivan assembly facility in Windsor. In 2010, a new agreement was reached with the OEFC to make the plant fully dispatchable in order to sell the remaining capacity and ancillary services to the Ontario power market when it is economical to do so.

Hydroelectric Facilities

Our Ontario hydroelectric facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Mississippi River System	ON	Appleton	1	100	1994	2030
Mississippi River System	ON	Galetta[2]	2	100	1998	2030
Montréal River System	ON	Ragged Chute	7	100	1991	-
Misema River System	ON	Misema	3	100	2003	2027
Wanapitei River System	ON	Moose Rapids	1	100	1997	2030
Total			**14**			

Notes:
(1) MW are rounded to the nearest whole number.
(2) Galetta was originally built in 1907, but was retrofitted in 1998.

Appleton is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Mississippi River, near Almonte, Ontario. We own this facility and it has been operating since 1994. Generation from this facility is sold to the OPA under a contract that terminates November 30, 2030.

Galetta is a run-of-river hydroelectric facility with installed capacity of 2 MW located on the Mississippi River, near Galetta, Ontario. We own Galetta, which was originally built in 1907 and retrofitted in 1998. Generation from this facility is sold to the OPA under a contract that terminates November 30, 2030.

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of New Liskeard, in northern Ontario. We own Ragged Chute and it has been operating since 1991. Generation from this facility is currently sold into the Ontario market, but application has been made to the OPA to contract the facility under its Hydroelectric Contract Initiative.

Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. We own this facility and it has been operating since 2003. Generation from this facility is sold to the OPA under a contract that terminates May 3, 2027.

Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. We own Moose Rapids and it has been operating since 1997. Generation from this facility is sold to the OPA under a contract that terminates November 30, 2030.

Wind Generation Facilities

Our Ontario, Québec and New Brunswick wind generation facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Melancthon Township	ON	Melancthon I	68	100	2006	2026
Melancthon and Amaranth Townships	ON	Melancthon II	132	100	2008	2028
Kingston	ON	Wolfe Island	198	100	2009	2029
Québec	QC	Le Nordais	99	100	1999	2033
Québec [2]	QC	New Richmond	66	100	2012	2031
Kent Hills	NB	Kent Hills	96	83	2008	2033
Kent Hills	NB	Kent Hills Expn.	54	83	2010	2035
Total			**647**			

Notes:
(1) MW are rounded to the nearest whole number.
(2) This facility is currently under development.

Melancthon I is a 68 MW wind project located in Melancthon Township near Shelburne, Ontario. We own the facility and it commenced commercial operations on March 4, 2006. Generation from this facility is sold to the OPA.

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

Wolfe Island is a 198 MW wind project located on Wolfe Island, near Kingston, Ontario. We own this facility and it commenced commercial operations on June 26, 2009. Generation from this facility is sold to the OPA.

Le Nordais is located at two sites: Cap-Chat with 56.25 MW of installed capacity; and Matane with 42.75 MW of installed capacity. Le Nordais is located on the Gaspé Peninsula of Québec. We own this facility and it commenced commercial operations in 1999. Generation from this facility is sold to Hydro-Québec.

Currently under development is our 68 MW New Richmond wind project also located on the Gaspé Peninsula. We received approval in March 2011 from the Government of Québec to proceed with construction. 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 $205 million and commercial operations are expected to commence during the fourth quarter of 2012.

Kent Hills is a 96 MW project located in Kent Hills, New Brunswick, and delivers power under a 25 year LTC with New Brunswick Power. Natural Forces Technologies Inc., an Atlantic Canada-based wind developer, is our co-development partner in this project and exercised its option to purchase up to 17 per cent of the Kent Hills project in May 2009. Kent Hills commenced commercial operations in 2008.

The Kent Hills expansion wind farm also delivers power under a 25 year LTC with New Brunswick Power. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills expansion project subsequent to the commencement of commercial operations. The facility commenced commercial operations on November 21, 2010.

All of the electricity generated and sold by our wind division with the exception of Ardenville, Blue Trail, Macleod Flats, and Summerview 2 is from facilities that are EcoLogo certified. We are an EcoLogo certified distributor of Alternative Source Electricity through Environment Canada's Environmental Choice program. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards.

TA Cogen

We hold a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent ownership is now held by Stanley Power Inc., a subsidiary of Cheung Kong Infrastructure Holdings Limited which amalgamated with Stanley Energy Inc., a subsidiary of Stanley Power Inc., on December 31, 2011.

TA Cogen holds interest in the 780 MW Sheerness thermal generation facility in Alberta, the 118 MW Fort Saskatchewan natural gas-fired cogeneration facility in Alberta, the 108 MW Mississauga, the 68 MW Ottawa and 68 MW Windsor natural gas-fired cogeneration facilities located in Ontario.

United States

Our generation facilities in the United States are summarized in the following table:

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

Note:

(1) Under IFRS, our interests in these facilities are accounted for as equity investments. Under Canadian GAAP, we previously proportionately consolidated our interests in the financial and operational results of these facilities.

Centralia

We own a two-unit 1,340 MW thermal facility and a 248 MW natural gas-fired facility in Centralia, Washington, located south of Seattle. We have entered into a number of multiple year medium and short- term energy sales agreements from the Centralia facility. We are currently in the process of pursuing long-term arrangements for Centralia. In 2011, Washington State passed the TransAlta Energy Bill (chapter 180, Laws of 2011) allowing the Centralia plant to comply with the State's GHG emissions performance standards by shutting down one of its two boilers by the end of 2020 and the other by the end of 2025. This legislation removed limitations that had previously been imposed on the facility limiting the duration of new contracts from the facility, and limiting the technology that the facility would be required to implement for nitrogen oxides ("NOx") controls. On December 23, 2011, TransAlta and the state entered into the MoA which confirmed these arrangements in contractual form with the provision that certain terms could terminate at TransAlta's option if it does not secure at least 500 MW of long-term contract for Centralia by the end of 2012. The MoA, by mutual consent, may be extended for a one year term. We also sell electricity from the Centralia facility into the Western Electricity Coordinating Council ("WECC") and, in particular, on the spot market in the U.S. Pacific

Northwest energy market. Our strategy is to balance contracted and non-contracted sales of electricity to manage production and price risk.

We also own a 1 MW hydroelectric generating facility on the Skookumchuck River near Centralia, and related assets which are used to provide water supply to our other generation facilities in Centralia. On December 10, 2010, we entered into an agreement with Puget Sound Energy Inc. for Skookumchuck to provide power until 2020.

We also own a coal mine adjacent to the Centralia facility; however, we stopped mining operations at our Centralia coal mine on November 27, 2006. Although we estimate that certain coal reserves remain to be extracted, we have not yet received permits for, nor developed the new area, from which this coal could be produced. Coal to fuel the Centralia plant is now sourced from the Powder River basin in Montana and Wyoming. Our existing coal contracts expire at the end of 2012. We expect to continue to source our future coal needs from the Powder River Basin. We have entered into contracts to purchase and transport coal from the Powder River Basin in Montana and Wyoming to fuel our facility until such time, if any, as it is economical to pursue the extraction of coal at our Centralia mine.

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

Under the U.S. Federal Mine Safety and Health Act, TransAlta must report all "significant and substantial" citations at its Centralia mine. During 2011, TransAlta had one reportable event relating to electric equipment and the examination, testing and maintenance thereof. The mine is not in operation. There were no injury incidents or fatalities at the mine during 2011. The total dollar value of all Mine Safety and Health Administration ("MSHA") assessments was not significant.

Reportable Events – Centralia Mine

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Initiated or Pending During Period (#)
4500416	1	243	0	No	No	0

CE Generation

We own 50 per cent of CE Generation, which, through its subsidiaries, is primarily engaged in the development, ownership and operation of independent power production facilities in the United States using geothermal and natural gas resources. CE Generation holds a net ownership interest of approximately 385 MW in 13 facilities, having an aggregate operating capacity of 829 MW, including 327 MW of geothermal generation in California and 502 MW of natural gas-fired cogeneration in New York State, Texas and Arizona.

CE Generation affiliates operate three natural gas-fired facilities in Texas, Arizona and New York State, having an aggregate generation capacity of 502 MW. The Arizona facility sells its output pursuant to long-term contracts while the Texas facility, until 2009, sold its output under a tolling agreement and has since moved to selling its output in the spot market. The New York State facility operates under the terms of an energy management agreement with a third party who is responsible for marketing the output from the facility and in return, the owners receive a fixed capacity payment and 80 per cent of dispatch revenue.

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

Wailuku

On February 17, 2006, a subsidiary of TransAlta, together with a subsidiary of MidAmerican Energy Holdings Company ("MidAmerican") entered into an arrangement to purchase a 10 MW hydro facility in Hawaii to be held directly by the Wailuku Holding Company, LLC. We own 50 per cent of this facility, with MidAmerican owning the other 50 per cent. The facility sells electricity pursuant to the terms of a 30-year long-term contract with the Hawaii Electricity Light Company.

Australia

We hold interests in Western Australia consisting of the 110 MW Parkeston generation facility through a 50/50 joint venture with NP Kalgoorlie Pty Ltd., a subsidiary of Newmont Australia Limited, and the 245 MW Southern Cross Energy natural gas and diesel generation facilities. Most of our generation supplies two large mining companies through long-term capacity contracts and the remaining amount of surplus energy and capacity is sold into Western Australia's Wholesale Electricity Market ("WEM").

Energy Trading Segment

Our Energy Trading group provides a number of strategic functions, including the following:

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

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

- Negotiating and managing fuel supply arrangements with third parties for our generation assets;

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

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

Beyond these functions, the Energy Trading group derives additional revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

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

We use mark to market valuation and the application of a value at risk ("VaR") determination for risk control practices for our trading portfolios. This approach is a measure of assessing the potential trading losses that we could experience over a given time due to fluctuations in energy prices in each market. Our policy is to actively manage and limit the group's aggregate VaR exposure within Board approved limits.

Competitive Environment

We are the largest generator of electricity in Alberta, measured by capacity, and have a significant portfolio of generation assets in the Pacific Northwest and the western U.S. We also own and operate generating assets in British Columbia, Ontario, Québec, New Brunswick, and Australia.

We expect electricity demand to grow as the economy slowly improves. In the long-term, most markets are expected to show growing demand for electricity; however, an increasing emphasis on efficiency may reduce future growth rates below historical levels. In addition to increased demand, many of the markets in which we participate have established renewable portfolio targets or standards that require new renewable power investments. As most forms of renewable generation also involve intermittent or uncertain levels and timing of production, higher levels of renewable generation may be accompanied by greater capacity requirements. We believe that continued and growing demand for electricity, renewable portfolio standards, and the potential of increasing amounts of renewable generation to require additional capacity, may provide an opportunity to increase our generation capacity.

Alberta is Canada's fourth largest province by population with approximately 3.7 million residents representing approximately 11 per cent of Canada's total population. Alberta consumed approximately 73,609 GWh of electricity in 2011, with a daily peak demand of 10,226 MW. As at December 31, 2011, the aggregate installed capacity of generating facilities in Alberta was approximately 13,100 MW[1].

British Columbia is Canada's third largest province by population with approximately 4.6 million residents, representing approximately 13.3 per cent of Canada's total population. In 2007, British Columbia adopted "The BC Energy Plan", which sets to "develop realistic and achievable goals for conservation, energy efficiency and clean energy". Under the BC Energy Plan, British Columbia will be self-sufficient by 2016. British Columbia's electricity hourly consumption averaged 6,629 MW in 2010 and 6,872 MW in 2011. The majority of the electricity is obtained from their hydro system.

Ontario is Canada's largest province by population with approximately 13.2 million residents representing approximately 38.7 per cent of Canada's total population. Ontario consumed approximately 141,471 GWh of electricity in 2011. Ontario Power Generation Inc., the successor to the generation business of Ontario's former integrated electric utility, controls 55 per cent of Ontario's approximately 33,980 MW of installed capacity. The balance is owned by municipal electric utilities and private independent power producers or industrial consumers.

Québec is Canada's second largest province by population with approximately 7.9 million residents, representing approximately 23.2 per cent of Canada's total population. The government in Québec has established the province's Energy Strategy which includes up to 4,500 MW of additional hydroelectric capacity and 4,000 MW of wind capacity to be installed by 2015.

New Brunswick is Canada's eighth largest province by population with approximately 0.8 million residents. In New Brunswick, the peak demand forecast for 2011/2012 is 3,020 MW, and the province has installed capacity of 4,302 MW including the Point Lepreau nuclear facility which is scheduled to be back online in October 2012. The New Brunswick market allows wholesale and industrial consumers to purchase power from either New Brunswick Power or a competing supplier. This competitive market does not extend to retail customers, businesses or small industries. In 2007, New Brunswick announced the Charter for Change requiring ten per cent of electricity purchases to be from renewable sources commencing in 2016.

Electrical utilities in western Canada, the northern portion of Baja California, Mexico and 14 western states are organized into the WECC. The WECC is the largest geographically of the ten regions in the North American Electric Reliability Council and is divided into four sub regions, of which Region 1 includes British Columbia, Alberta, Washington, Oregon, Idaho, Montana, Utah, Western Wyoming and Northern Nevada. This sub region is referred to as the Northwest Power Pool ("NWPP"). It is estimated that approximately 380,776 GWh of electricity were consumed in the NWPP in 2011. The WECC also reported an estimated aggregate electrical generating capacity of approximately 100,836 MW in the NWPP for the year ending December 31, 2011.

[1] Excludes Sundance Unit 1 and Unit 2 capacity.

Australia is heavily dependent on coal for electricity, with over 75 per cent of the power produced derived from coal. Natural gas is increasingly used for electricity, especially in South Australia and Western Australia. The major reform in the Australian electricity industry involved the establishment in southern and eastern Australia of the National Electricity Market ("NEM"). In Western Australia, where our power assets are located, a new WEM was introduced in late 2006. Total installed capacity in the WEM is about 5,500 MW, while TransAlta's capacity in the region is approximately 300 MW.

Total electricity consumption in Western Australia is expected to increase strongly driven by projects in the minerals and energy industry. The Chamber of Minerals and Energy of Western Australia estimates that the electricity growth rate over the period to 2020 will be 6.9 per cent per annum. WEM has approved and assigned a total of 6,086 MW of Capacity to 32 generation providers for 2013 to 2014. We enjoy a solid competitive advantage in power supply to mining operations, especially remote mining operations, and have built up significant knowledge and expertise in this field.

Competitive Strengths

We believe that we are well positioned to achieve our business strategy due to our competitive strengths, which include the following:

Financial strength – We have investment grade ratings from Moody's Investor Services, Inc. ("Moody's"), Standard & Poor's, a division of the McGraw Hill Companies, Inc. ("S&P") and Dominion Bond Rating Service Limited ("DBRS").

Stable cash flow base – Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 70 per cent of our capacity is contracted over the next seven years. The net revenue received under these contractual arrangements helps to minimize short-term revenue fluctuations due to the variable price of electricity.

Fuel diversity – We have a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, geothermal and wind. We believe that this mix reduces the impact on our performance in the event of external events affecting one fuel source.

Management team – Our management team has substantial industry, international, and local market experience.

Energy Trading expertise – We believe that our Energy Trading group has enhanced returns from our existing generation base and has allowed us to obtain more favourable pricing for uncommitted electricity, secure fuel supply on a cost effective basis and fulfill electricity delivery obligations in the event of an outage.

Ownership or control of coal supply – We own, control or lease coal reserves in Alberta which provide a long-term and stable source of fuel for our thermal generation facilities in Alberta. Our mines in Alberta contain some of the lowest sulphur coal in North America, averaging 0.25 per cent sulphur at the Highvale mine. Coal with lower sulphur content emits less sulphur dioxide ("SO_2") when it is burned.

Wind Generation – We are the largest owner and operator of wind generation in Canada. Our management team has developed key relationships with customers, suppliers and policy makers that provide a competitive advantage in the development, operations and marketing of wind generation.

Environment – We are a recognized leader in sustainable development and we have taken early preventative action on a number of environmental fronts in advance of regulation.

Corporate Segment

Our Corporate Segment provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, procurement, information technology, risk management, human resources, internal audit, and other administrative services, including compliance and governance services to support our Generation and Energy Trading groups.

For further information on TransAlta's segment earnings and assets, please refer to Note 36 of our audited consolidated financial statements for the year ended December 31, 2011, which financial statements are incorporated by reference herein. See "Documents Incorporated by Reference" herein.

ENVIRONMENTAL RISK MANAGEMENT

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

Ongoing and Recently Passed Environmental Legislation

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

Alberta

In Alberta there are requirements for coal-fired generation units to implement additional air emission controls for NOx, SO_2 and particulate matter once they reach the end of their Power Purchase Arrangements – in most cases at 2020. These regulatory requirements were developed by the Province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance (CASA). However, as new greenhouse gas regulations for coal-fired power are developed there is a risk that the CASA air pollutant requirements and schedules become misaligned with GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2 and particulates. TransAlta is in discussions with both the federal and provincial governments to ensure coordination between greenhouse gas and air pollutant regulations, such that emission reduction objectives are achieved in the most economically effective manner while maintaining the reliability of Alberta's generation supply.

Canada

On August 27, 2011, the Government of Canada published in the Canada Gazette draft regulations entitled "Reduction of CO_2 Emissions from Coal-Fired Generation of Electricity". These regulations propose a 45-year end-of-life for coal-fired power units, at which point the units would have to meet a GHG emissions performance standard similar to natural gas-fired levels, or close. Should they be passed, the regulations would become effective on July 1, 2015. Under federal consultation provisions, industry, provinces, and other stakeholders have 60 days to provide comments on the regulations and subsequently the federal government will consider this input in the development of the second draft.

We are currently in discussions with both the Governments of Canada and Alberta about modifications to the regulations that would result in significant GHG emission reductions and which would provide alignment with the industry and other current and future regulations on air pollutants and natural gas generation. These discussions are expected to continue through early 2012.

United States

The Environmental Protection Agency ("EPA") announced on September 14, 2011, that it was further delaying the release of draft GHG regulations for new and modified coal-fired power plants beyond its September 30, 2011 target date. Draft regulations are expected in early 2012. There are no announced plans for new GHG regulations for existing power plants such as our Centralia plant.

In December 2011, the EPA issued national standards for mercury pollution from power plants. Existing sources will have up to four years to comply. We are already proceeding with the installation of voluntary mercury capture technology at our Centralia coal-fired plant, which we expect to be operational in 2012. That plant is also planning for the installation of additional capture technology to further reduce NOx, consistent with the Washington State Bill passed in April 2011 requiring TransAlta to begin operating such technology by January 1, 2013.

In addition to the Federal, Regional and State regulations that we must comply with, we also comply with the standards established by the North American Electric Reliability Corporation ("NERC"). NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually; monitors the bulk-power system; and educates, trains and certifies industry personnel.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We expect that increased scrutiny will be placed on environmental emissions and compliance. We, therefore, take a proactive approach to minimizing risks to our results. Our Board provides oversight to our environmental management programs and emission reduction initiatives.

Our environmental management programs encompass the following elements:

Renewable Power

Our investment in renewable power sources continues through the building of renewable power resources. Our Bone Creek hydro facility became operational in 2011, with our 68 MW New Richmond wind facility in construction and slated for 2012. A larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or through offsets.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Alberta thermal operations in 2010 in order to meet the province's 70 per cent reduction objectives. Our new Keephills 3 plant began operation in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at our Genesee 3 plant. Uprate projects at our Keephills and Sundance plants were undertaken in 2011 and scheduled for completion in 2012, which will improve the emissions efficiency of those units.

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

Policy Participation

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

CCS Development

In October 2009, the Governments of Canada and Alberta announced that Project Pioneer, our CCS project, had received funding commitments of more than $770 million. Since then, we have advanced engineering work on the capture, pipeline, and storage components of the project and are assessing if costs and other commercial terms and risks are appropriate to ensure the project is viable from a business perspective. The prototype plant, if built, will be one of the largest integrated CCS power facilities in the world, designed to capture one megatonne of carbon dioxide ("CO_2") per year from our 450 MW Keephills Unit 3 coal-fired plant. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site.

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

Offsets Portfolio

TransAlta maintains an offset portfolio with a variety of instruments than can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emission offset opportunities that also allow us to meet emission targets at a competitive cost. We ensure that any investments in offsets will meet certification criteria in the market in which they are to be used.

Environmental Regulations

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

RISK FACTORS

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

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

The operation and maintenance of our facilities involves risks that may materially and adversely affect our business.

The operation, maintenance, refurbishment, construction and expansion of power generation facilities involve risks, including breakdown or failure of equipment or processes, fuel interruption and performance below expected levels of output or efficiency. Certain of our generation facilities, particularly in Alberta, were constructed many years ago and may require significant capital expenditures to maintain peak efficiency or to maintain operations. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities prior to occurrence or eliminate all adverse consequences in the event of failure. In addition, weather related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of our facilities and may materially adversely affect us.

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

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

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

Equipment failure may cause us to suffer a material adverse effect.

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

We could be adversely affected by natural disasters or other catastrophic events.

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

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

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

We may be adversely affected if our supply of water is materially reduced.

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

Variation in wind levels may negatively impact the amount of electricity generated at our wind facilities.

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

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

Changes in the price of electricity and availability of fuel supplies required to generate electricity may materially adversely affect our business.

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

We buy natural gas and a portion of our coal to supply the fuel needed to generate electricity. We could be materially adversely affected if the cost of fuel that we must buy to generate electricity increases to a greater degree than the price that we can obtain for the electricity that we sell. Several factors affect the price of fuel, many of which are beyond our control, including:

- prevailing market prices for fuel;
- global demand for energy products;
- the cost of carbon and other environmental concerns;
- weather-related disruptions affecting the ability to deliver fuels or near-term demand for fuels;
- increases in the supply of energy products in the wholesale power markets;
- the extent of fuel transportation capacity or cost of fuel transportation service into our markets; and
- the cost of mining that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

Changes in any of these factors may increase our cost of producing power or decrease the amount of revenue received from the sale of power, which could have a material adverse effect on us.

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

Adverse changes in general economic and market conditions could negatively impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, credit risk and counterparty risk, which could cause us to suffer a material adverse effect. Changes in interest rates can impact our borrowing costs and the capacity revenues that we receive pursuant to the Alberta PPAs.

Under the government mandated Alberta PPAs, pursuant to which we operate most of our thermal and hydroelectric facilities in Alberta, we are subject to certain risks, including the possibilities of penalties for unplanned outages and the burden of increased costs required to maintain and operate our generation facilities.

The majority of our Alberta thermal and hydroelectric generating plants operate under the Alberta PPAs, which establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each coal-fired plant, energy and ancillary services obligations for the hydroelectric plants, and the compensation for meeting the PPA obligations. Under the Alberta PPAs applicable to coal-fired plants, in the event of an unplanned outage other than an outage determined to be caused by *force majeure*, we must pay a penalty for the lost production based upon a price equal to the 3- day trailing average of Alberta market electricity prices. Consequently, an unplanned outage could have a material adverse effect on us.

We bear some of the impact of increases in our operating costs (other than increases arising as a result of a "change of law" as such term is defined in the Alberta PPAs) because the price which we are able to receive for our capacity under the Alberta PPAs is based on a schedule of forecast fixed costs. Many of the forecast costs will be determined by indices, formulae or other means for the entire term of the Alberta PPAs. Our actual results will vary and depend on performance compared to the forecasts on which the Alberta PPAs are based. Operating costs could increase as a result of a number of factors which are beyond our control. A significant increase in our operating costs could have a material adverse effect on our business.

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

We operate in a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the United States and Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity and international conglomerates. Some competitors have significantly greater financial and other resources than we do. Competitive harm could have a material adverse effect on our business.

Variations in weather can affect demand for electricity and our ability to generate electricity.

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

We may be unsuccessful in the defence of legal actions.

We are occasionally named as a defendant in claims and legal actions and as a party in commercial disputes which are resolved by arbitration. There can be no assurance that we will be successful in the defence of these claims and legal actions or that any claim or legal action that is decided adverse to us will not materially and adversely affect us.

The laws and regulations in the various markets in which we operate are subject to change, which may materially adversely affect us.

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

Regulatory authorities may also from time to time investigate our activities in the markets in which we operate or pursue trading. Such investigations may result in sanctions or penalties which may materially affect our future activities or financial status.

Our facilities are also subject to various licensing and permitting requirements in the jurisdictions in which we operate. Many of these licenses and permits need to be renewed from time to time. If we are unsuccessful in renewing such licenses or permits, or the terms of such licenses or permits are changed in a manner that is adverse to our business, we could be materially adversely affected.

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

Our business could be materially affected by the Dodd-Frank Act, including greater regulation of over-the-counter derivatives, which could materially affect our ability to hedge economically our generation.

Title VII of the Dodd-Frank Act increases the regulation of transactions involving over-the-counter ("OTC") derivative financial instruments, including the requirement for central clearing of many OTC derivatives transactions with clearing organizations. The effect of the Dodd-Frank Act on our business depends on pending rulemaking proceedings and, in particular, the final definitions for the key terms "Swap Dealer" and "End-User". Entities defined as Swap Dealers will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. Designation as a Swap Dealer could materially adversely affect our ability to economically hedge our generation, by reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with these activities. It is not known at this time whether, and, if so, to what extent, we will be required to provide collateral (for both our cleared and uncleared transactions) in excess of what we currently provide under our existing hedge relationships. Other features of the Dodd-Frank Act which will have an impact on our derivatives activities include trade reporting, position limits and trade execution. Many aspects of the Dodd-Frank Act are subject to rulemaking that will take effect over several years which makes it difficult to assess its full impact on us at this time.

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

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

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

A number of recent federal, provincial, state and local regulatory efforts continue to focus on potential climate change or GHG emissions regulation, and mandatory GHG reporting requirements have become effective for 2010 in both Ontario and the United States. In Canada, the U.S. and Australia, GHG legislation or alternative forms of regulation are still under development, and it is too early to determine their impacts. Mandatory GHG emissions reductions requirements are expected to impose increased costs on our business, as is expected to be the case generally for thermal power producers in North America. We are subject to other air quality regulations including mercury regulations. At this time, we cannot assess the potential impact of future mercury regulations at our United States facilities. To the extent new or additional GHG, mercury or other air emission regulations may require us to incur costs that cannot be passed through to our customers under its power purchase agreements, including Alberta PPAs or otherwise, the costs could be material and have a material adverse effect on our business.

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

Changes in opinions of our Corporation from external parties may have a material adverse effect on us.

Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, and other entities. Our reputation is one of our most valued assets.

We manage reputation risk by:

- striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders;
- clearly communicating our business objectives and priorities to a variety of stakeholders on a routine basis;
- maintaining positive relationships with various levels of government;
- pursuing sustainable development as a longer-term corporate strategy;
- ensuring that each business decision is made with integrity and in line with our corporate values; and
- communicating the impact and rationale of business decisions to stakeholders in a timely manner.

We are dedicated to operating a safe and ethical organization. We have a system in place where employees may report any potential ethical concerns. These concerns are directed to the Director, Internal Audit who engages Corporate Security, Legal, and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the chair of the Audit and Risk Committee ("ARC"). All employees and directors are required to sign a corporate code of conduct on an annual basis.

Our information technology systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyber-attack and other similar disruptions, all of which could have a material adverse effect on our business.

We have put in place a number of systems, processes and practices designed to protect against intentional or unintentional misappropriation or corruption of our systems and information or disruption of our operations. Despite our implementation of security measures, our IT systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyber-attack and other similar disruptions. Any system failure, accident or security breach could result in disruptions to our operations and a loss of confidential or proprietary data which could adversely affect our reputation, diminish customer confidence, disrupt operations, and subject us to possible financial liability, any of which could have a material adverse effect on our financial condition and results of operations. We closely monitor both preventive and detective measures to manage these risks.

We rely on transmission lines that we do not own or control, which may hinder our ability to produce, sell and deliver electricity.

We depend on transmission and distribution facilities that are owned and operated by utilities and other power companies to deliver the electricity that we generate. An extended disruption in transmission, a failure in the transmission system or a lack of available transmission and distribution facilities could impact our ability to produce, sell and deliver electricity, which could have a material adverse effect on our business.

Trading risks may have a material adverse effect on our business.

Our trading and marketing business frequently involves the establishment of trading positions in the wholesale energy markets on both a medium-term and short-term basis. To the extent that we have long positions in the energy markets, a downturn in market prices will result in losses from a decline in the value of such long positions. Conversely, to the extent that we enter into forward sales contracts to deliver energy that we do not own, or take short positions in the energy markets, an upturn in market prices will expose us to losses as we attempt to cover any short positions by acquiring energy in a rising market.

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

If the strategy that we use to hedge our exposures to these various risks is not effective, we could incur significant losses. Our trading positions can be impacted by volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short-term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect our positions which could also have a material adverse effect on our business.

While we use a number of risk management controls conducted by our independent Risk Management group to limit our exposure to risks arising from our trading activities, including VaR, stop loss restrictions, stress testing, volumetric and term limits and restrictions on authorized instruments, we cannot guarantee that losses will not occur and such losses could materially adversely affect us.

Because of our multinational operations, we are subject to currency rate risk and regulatory and political risk.

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services from foreign suppliers, and our U.S. denominated debt. Our exposures are primarily to the U.S., Australian and Euro currencies. Changes in the values of these currencies relative to the Canadian dollar could negatively impact our earnings or the value of our foreign investments. While we attempt to manage this risk through the use of hedging instruments, including cross-currency interest rate swaps, forward exchange contracts and by matching revenues and expenses by currency at the Corporate

level, there can be no assurance that these risk management efforts will be effective, and fluctuations in these exchange rates may have a material adverse effect on our business.

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

We may have difficulty raising needed capital in the future, which could significantly harm our business.

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

Our debt securities will be structurally subordinated to any debt of our subsidiaries that are currently outstanding or may be incurred in the future.

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

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

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

Changes in statutory or contractual restrictions that affect our corporate structure may have a material adverse effect on us.

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by our subsidiaries in the form of distributions, loans, dividends, or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

Certain of the contracts to which we are a party require that we provide collateral against our obligations.

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

If counterparties to our contracts are unable to meet their obligations, we may be materially and adversely affected.

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

Insurance coverage may not be sufficient.

We have insurance for our facilities, including all risk property insurance, commercial general liability insurance and boiler and machinery coverage in amounts and with deductibles that we consider appropriate. We also carry business interruption insurance for certain of our facilities where we do not otherwise have contractual arrangements to address these potential losses or where in other cases it would not be economical to do so.

Our insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for any loss or damage to any of our generation facilities may not be sufficient to permit us to continue to make payments on our debt.

Provision for income taxes may not be sufficient.

Our operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. In addition, our tax filings are subject to audit by taxation authorities. While we believe that our tax filings have been made in material compliance with all applicable tax interpretations, regulations, and legislation, we cannot guarantee that we will not have disagreements with taxation authorities with respect to our tax filings that could have a material adverse effect on our business.

If we fail to attract and retain key personnel, we could be materially adversely affected.

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

If we are unable to successfully negotiate new collective bargaining agreements with our unionized workforce, as required from time to time, we will be adversely affected.

While we believe we have a satisfactory relationship with our unionized employees, we cannot guarantee that we will be able to successfully negotiate or renegotiate our collective bargaining agreements on terms agreeable to TransAlta. We expect to re-negotiate two collective bargaining agreements, involving 86 of our employees, in 2012 and an additional seven collective bargaining agreements, involving 801 of our employees, in 2013. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

Risks relating to TransAlta's development projects and acquisitions may materially and adversely affect us.

Development projects and acquisitions that we undertake may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third party opposition, cost escalations, construction delays, shortages of raw materials or skilled labour and capital constraints. The occurrences of these risks could have a material and adverse impact on us, our financial condition, results of operations and cash flows.

Expansion of our business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully

manage or integrate any acquired businesses or development projects could have a material adverse impact on us, our financial condition, results of operations and cash flows. Further, we cannot make assurances that we will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

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

EMPLOYEES

As of December 31, 2011, we had 2,195 active employees, which is comprised of full-time, part-time and temporary employees, of which 1,527 were employed in our Generation business and 75 were employed in our Energy Trading business. Approximately 42 per cent of our employees are represented by labour unions. We are currently a party to 11 different collective bargaining agreements. In 2011, we renewed two of the agreements, which expired March 31, 2011 and October 18, 2011, respectively. Four agreements are expected to be re-negotiated in 2012.

CAPITAL STRUCTURE

General

Our authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. As at February 29, 2012, there were 224,676,719 common shares outstanding and 12,000,000 Series A and 11,000,000 Series C first preferred shares outstanding.

Common Shares

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

First Preferred Shares

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

The first preferred shares of all series rank senior to all other shares of TransAlta Corporation with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board at the rate established by the Board at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of TransAlta Corporation unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of TransAlta Corporation until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares

to the date of such liquidation, dissolution, winding up, or reduction of stated capital, as applicable. After payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of our assets.

The Board may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon our failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25.00 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of TransAlta if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

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

Series A Shares

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

Dividends on Series A Shares

The holders of Series A Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series A Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares and the Series B Shares described below, and will remain unchanged over the life of the Series A Shares.

Redemption of Series A Shares

The Series A Shares are redeemable by TransAlta in whole or in part, on or after March 31, 2016, and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

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

Conversion of Series A Shares into Series B Shares

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

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

Modification

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

Series C Shares

The Series C rate reset preferred shares were issued on November 30, 2011 with a coupon of 4.60 per cent ("Series C Shares"), as discussed in the section entitled General Development of the Business. Certain provisions of the Series C Shares are discussed below.

Dividends on Series C Shares

The holders of Series C Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series C Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 3.10 per cent. This spread will apply to both the Series C Shares and the Series D Shares described below, and will remain unchanged over the life of the Series C Shares.

Redemption of Series C Shares

The Series C Shares are redeemable by TransAlta in whole or in part, on or after June 30, 2017, and on June 30 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

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

Conversion of Series C Shares into Series D Shares

The holders of the Series C Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series D of TransAlta (the "Series D Shares"), subject to certain conditions, on June 30, 2017 and on June 30 in every fifth year thereafter. The holders of the Series D Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.10 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.10 per cent.

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

Modification

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

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

On February 21, 2012, TransAlta Corporation added a Premium Dividend™ Component to its existing Dividend Reinvestment and Share Purchase Plan. The amended and restated plan, the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan provides eligible shareholders of TransAlta with two options: i) to reinvest dividends at a current three per cent discount (may be from zero to five per cent at the discretion of the Board of Directors) to the average market price towards the purchase of new shares of TransAlta (the Dividend Reinvestment Component) or ii) receive the equivalent to 102% of the dividends payable in cash, a premium cash payment (the Premium Dividend™ Component).

Eligible shareholders enrolled in either the Dividend Reinvestment Component or the Premium Dividend™ Component will also be eligible to purchase new shares at a discount to the average market price under the optional cash payment component (the OCP Component) of the plan by directly investing up to $5,000.00 per quarter. The applicable discount under the OCP Component is also determined from time to time by the Board and is currently set at three per cent.

CREDIT RATINGS

Issuer Rating

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

As of December 31, 2011, our issuer rating from S&P was BBB (negative).

Senior Unsecured Long-term Debt

As of December 31, 2011, our senior unsecured long-term debt is rated BBB (stable) by DBRS, BBB (stable) by S&P and Baa2 (negative outlook) by Moody's. The ratings for debt instruments range from a high of AAA to a low of D in the case of both DBRS and S&P and from a high of Aaa to a low of C in the case of Moody's.

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

According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on such obligations than on obligations in the higher rating categories. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (–) sign to show relative standing within the major rating categories. S&P also assigns a rating outlook to each of its ratings to give investors an understanding of S&P's opinion regarding the potential direction for the long-term credit rating over the intermediate term.

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

Preferred Shares

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

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

According to the S&P rating system, securities rated P-3 are of adequate credit quality. The ratings from P-1 to -5 may be modified by "high" or "low" grades which indicate relative standing within the major rating categories.

Note Regarding Credit Ratings

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

DIVIDENDS

Common Shares

Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, our results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

TransAlta has declared and paid the following dividends per share on its outstanding common shares for the past three years:

Period		Dividend per Common Share
2009	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29
2010	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29
2011	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29

On January 25, 2012, the Board declared a cash dividend of $0.29 per common share, payable on April 1, 2012 to shareholders of record on March 1, 2012.

Series A Shares

Period		Dividend per Series A Preferred Share
2010	Fourth Quarter[(1)]	$0.3497
2011	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875

Note:

(1) On December 31, 2010, the Board approved an initial dividend of $0.3497 per share on our issued and outstanding Series A Shares for the period from December 10, 2010 to March 31, 2011.

On January 25, 2012, the Board declared a cash dividend of $0.2875 per Series A Preferred share, payable on March 31, 2012 to shareholders of record on March 1, 2012.

Series C Shares

On January 25, 2012 the Board approved an initial dividend of $0.3844 per Series C Preferred share for the period from issuance of November 30, 2011 to March 31, 2012. The dividend is payable on March 31, 2012 to shareholders of record on March 1, 2012.

MARKET FOR SECURITIES

Common Shares

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

	Price ($)		
Month	**High**	**Low**	**Volume**
2011			
January	22.09	22.60	10,286,275
February	21.25	20.31	16,826,608
March	20.69	19.50	14,424,192
April	21.08	20.02	7,455,909
May	21.99	20.88	12,270,440
June	21.51	20.42	8,642,075
July	21.34	20.51	6,201,288
August	22.09	19.44	20,005,806
September	23.20	21.26	14,027,245
October	23.42	21.74	13,101,345
November	22.10	20.55	12,211,216
December	22.28	20.38	16,691,451
2012			
January	21.51	20.00	15,700,737
February 1 to 29	21.20	20.27	13,235,698

Series A Shares

Our Series A Shares are listed on the TSX under the symbol "TA.PR.D".

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

	Price ($)		
Month	**High**	**Low**	**Volume**
2011			
January	25.50	25.00	494,424
February	25.45	24.59	240,361
March	25.34	25.50	195,505
April	25.23	24.80	225,573
May	25.40	25.00	188,339
June	25.48	24.61	361,784

July	25.35	24.80	115,272
August	25.63	24.85	168,191
September	25.79	25.00	150,821
October	25.75	24.90	226,538
November	25.25	24.75	311,585
December	25.48	24.86	102,976
2012			
January	25.71	24.87	235,338
February 1 to 29	25.89	24.94	131,209

Series C Shares

Our Series C Shares are listed on the TSX under the symbol "TA.PR.F".

Date(s) of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
November 30, 2011[(1)]	11,000,000 Series C Shares	$25.00	Public Offering

Note:

(1) Series C Shares were issued pursuant to a public offering in a prospectus supplement dated November 23, 2011. See "General Development of the Business –Year Ended December 31, 2011".

	Price ($)		
Month	**High**	**Low**	**Volume**
2011			
November 30	24.95	24.85	219,150
December	25.32	24.46	637,856
2012			
January	25.60	25.16	797,165
February 1 to 29	25.90	25.13	400,185

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of our directors as at February 29, 2012, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve to the Board is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence[(1)]	Year first became Director	Principal Occupation
William D. Anderson Ontario, Canada	2003	***Corporate Director.*** Mr. Anderson was President of BCE Ventures (a subsidiary of BCE Inc.) from 2001 to 2005 (telecommunications) and prior to that, Chief Financial Officer ("CFO") of BCE Inc., Bell Canada Inc. and of Bell Cablemedia plc (telecommunications). As President of BCE Ventures, he was responsible for a number of significant operating companies as well as being Chief Executive Officer ("CEO") of Bell Canada International Inc. In his CFO roles, Mr. Anderson was responsible for all financial operations of the respective companies and executed numerous debt and equity financings, corporate acquisition and disposition transactions as well as corporate and operational restructurings. Mr. Anderson is the Chair of Gildan Activewear Inc. and Nordion Inc. and a director of Sun Life Financial Inc. He is a past director at BCE Emergis Inc., Bell Cablemedia plc, Bell Canada International Inc., CGI Group Inc., Four Seasons Hotels Inc., Sears Canada Inc. and Videotron Holdings plc. At TransAlta, Mr. Anderson is Chair of the Audit and Risk Committee of the Board. Mr. Anderson holds a bachelor in business administration from the University of Western Ontario (London, ON) and is a Fellow of the Institute of Chartered Accountants of Ontario.
Stephen L. Baum New Hampshire, U.S.A.	2008	***Corporate Director***. Mr. Baum was Chairman and CEO of Sempra Energy from July 2000 to February 2006, a San Diego-based Fortune 500 energy services holding company formerly known as Enova Corporation. Previous to that, Mr. Baum was President, COO and Vice-Chairman of Sempra Energy, from July 1998 to July 2000. Prior to that, he was Chairman, CEO and a member of the board of directors of Enova Corporation, the parent company of San Diego Gas & Electric ("SDG&E") where he served in various officer positions including General Counsel. Before joining SDG&E, he was Senior Vice-President and General Counsel of the New York Power Authority. He has also held various legal positions, including General Attorney at Orange & Rockland Utilities, and as an associate with the law firm of Curtis, Mallet-Prevost, Colt & Mosle in New York City. Mr. Baum is a member of the board of directors of Computer Sciences Corporation. At TransAlta, Mr. Baum is a member of the Audit and Risk Committee of the Board. Mr. Baum is a graduate of Harvard University (Cambridge, MA) and the University of Virginia Law School (Charlottesville, VA). He has also served as a Captain in the U.S. Marine Corps.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Timothy W. Faithfull England, U.K.	2003	***Corporate Director***. Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc (energy), where he held diverse international roles principally in oil products and LNG project development. As President and CEO of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line in 2003, the first fully integrated oil sands venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operations of Shell International Trading and Shipping Company from 1993 to 1996. He was Chairman and CEO of Shell Eastern Petroleum in Singapore from 1996 to 1999, including Shell's main refinery and oil products trading for Asia Pacific. During his time in Singapore, he was a director of DBS Bank and the Port of Singapore Authority. He was a trustee of the main Singapore Arts/Theatre complex. In Calgary, he served on the board of the Calgary Health Trust and the Epcor Arts Centre. Mr. Faithfull is a director of AMEC plc, Canadian Pacific Railway Limited and Canadian Natural Resources Limited. In the U.K., Mr. Faithfull is a director of Shell Pension Trust Limited, where he chairs the Technical Committee. He is a trustee of both Starehe UK and Canada UK Colloquium, and a member of the remuneration committee of Keble Collete, Oxford, all non-public entities. He is a past director of Enerflex Systems Income Fund. At TransAlta, Mr. Faithfull is Chair of the Human Resources Committee of the Board. Mr. Faithfull holds a master of arts in philosophy, politics and economics from the University of Oxford, U.K. (Oxford, U.K.).

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Dawn L. Farrell Alberta, Canada	2012	***President and Chief Executive Officer of TransAlta Corporation***. Mrs. Farrell has been President and CEO of TransAlta Corporation since January 2, 2012. Prior to this appointment, she was Chief Operating Officer from 2009 to 2011 and from 2008 to 2009 Executive Vice-President Commercial Operations and Development. Mrs. Farrell has over 25 years' experience in the electric energy industry, holding various roles at TransAlta and BC Hydro. She has served as Executive Vice-President, Corporate Development; Executive Vice-President, Independent Power Projects; and Vice-President, Energy Marketing and IPP Development at TransAlta Corporation. At BC Hydro, she served as Executive Vice-President Engineering, Aboriginal Relations and Generation and Executive Vice-President, Generation. Mrs. Farrell is a director of the Calgary Stampede. She is also a past director or governor of Mount Royal College Board of Governors, Fording Coal Income Fund, New Relationship Trust Fund, Mount Royal College Foundation and Vision Quest Windelectric. She holds a bachelor of commerce degree with a major in finance and a master's degree in economics from the University of Calgary (Calgary, AB). Mrs. Farrell has also attended the Advanced Management Program at Harvard University (Cambridge, MA).
Amb. Gordon D. Giffin[2] Georgia, U.S.A.	2002	***Lawyer and Senior Partner, McKenna, Long & Aldridge LLP (law firm)***. From 1997 to 2001, Mr. Giffin served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy. Prior to this appointment, he practised law for 18 years as a senior partner in Atlanta, GA and Washington, DC. His practice focused on energy regulatory work at the state and federal levels. Prior to that, he served as Chief Counsel and Legislative Director to United States Senator Sam Nunn, with responsibility for the legal and legislative operations of the office. In 2001, Mr. Giffin returned to private practice where he specializes in state and federal regulatory matters, including those related to trade, energy and trans-border commerce. Mr. Giffin is a director of Canadian Imperial Bank of Commerce, Canadian National Railway Company, Canadian Natural Resources Limited and Just Energy Group Inc. At TransAlta, Mr. Giffin is Chair of the Board. Mr. Giffin holds a bachelor of arts from Duke University (Durham, NC) and a *juris* doctorate from Emory University School of Law (Atlanta, GA).

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
C. Kent Jespersen[3] Alberta, Canada	2004	***Corporate Director.*** Mr. Jespersen has been Chair and CEO of La Jolla Resources International Ltd. since 1998 (advisory and investments). He has also held senior executive positions with NOVA Corporation of Alberta, Foothills Pipe Lines Ltd. and Husky Oil Limited before assuming the presidency of Foothills Pipe Lines Ltd. and later, NOVA Gas International Ltd. ("NOVA"). At NOVA, he led the non-regulated energy services business (including energy trading and marketing) and all international activities. Mr. Jespersen is a director of Axia NetMedia Corporation, CanElson Drilling Inc., Rodinia Oil Corp., Orvana Minerals Corp., MatRRix Energy Technologies Inc. and Petro-Frontier Ltd. At TransAlta, Mr. Jespersen is a member of the Human Resources Committee of the Board. Mr. Jespersen holds a bachelor of science in education and a master of science in education from the University of Oregon (Eugene, OR).
Michael M. Kanovsky Alberta, Canada	2004	***Corporate Director and Independent Businessman***. Mr. Kanovsky co-founded Northstar Energy Corporation ("Northstar") with initial capital of $400,000 and helped build this entity into an oil and gas producer that was sold to Devon Energy Corporation for approximately $600 million in 1998. During this period, Mr. Kanovsky was responsible for strategy and finance as well as merger and acquisition activity. He initiated Northstar's entry into electrical cogeneration through its wholly-owned power subsidiary, Powerlink Corporation ("Powerlink"). Powerlink developed one of the first independent power producer (IPP) gas-fired co-generation plants in Ontario and also internationally. In 1997, he founded Bonavista Energy Trust, which has grown to a present day market capitalization of approximately $4.5 billion. Mr. Kanovsky is a director of ARC Resources Ltd., Bonavista Energy Corporation, Devon Energy Corporation and Pure Technologies Ltd. At TransAlta, Mr. Kanovsky is Chair of the Governance and Environment Committee of the Board. Mr. Kanovsky, a Professional Engineer, holds a bachelor of science in mechanical engineering from Queen's University (Kingston, ON) as well as a master of business administration from the Richard Ivey School of Business at the University of Western Ontario (London, ON).

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Gordon S. Lackenbauer[4] Alberta, Canada	2005	***Corporate Director***. Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. (investment banking) from 1990 to 2004. Prior to that, he was responsible for the principal activities of the firm, which included fixed income sales and trading, new issue underwriting, syndication and merger and acquisition advisory mandates. Mr. Lackenbauer has worked with many of Canada's leading utilities and has frequently acted as an expert financial witness testifying on the cost of capital, appropriate capital structure, and the fair rate of return, principally before the Alberta Utilities Commission, the National Energy Board and the Ontario Energy Board. Mr. Lackenbauer is a director of NAL Energy Corporation and was a director of CTV Globemedia Inc., a non-public entity, from 2006 to 2011. At TransAlta, Mr. Lackenbauer is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board. Mr. Lackenbauer holds a bachelor of arts in economics from Loyola College (Montréal, QC) as well as a master of business administration from the University of Western Ontario (London, ON). He is also a Chartered Financial Analyst.
Karen E. Maidment Ontario, Canada	2010	***Corporate Director***. Ms. Maidment was Chief Financial and Administrative Officer ("CFAO") of BMO Financial Group ("BMO") from 2007 to 2009. Prior to that, she was Senior Executive Vice-President and CFO from 2003 to 2007 and Executive Vice-President and CFO of BMO from 2000 to 2003. As CFAO of BMO, she was responsible for all global finance operations, risk management, legal and compliance, communications and mergers and acquisitions. Ms. Maidment has also held several executive positions with Clarica Life Insurance Company ("Clarica") from 1988 to 2000, including CFO. Ms. Maidment is a director of TD Ameritrade Holding Corporation and The Toronto-Dominion Bank. She is a past director of Harris Bank, BMO Nesbitt Burns, where she was also Chair of the Audit Committee, Bank of Montreal Pension Fund, Mutual Trustco, MCAP Financial and The Mutual Group (U.S.). She is a member of the Princess Margaret Hospital Foundation Board and serves on the University of Waterloo Board of Governors. At TransAlta, Ms. Maidment is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board. Ms. Maidment holds a bachelor of commerce from McMaster University (Hamilton, ON), is a Chartered Accountant and, in 2000, was named Fellow of the Institute of Chartered Accountants of Ontario.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
Yakout Mansour California, U.S.A.	2011	***Corporate Director***. Mr. Mansour has over 40 years of experience in a wide variety of professional, managerial and executive leadership capacities in the electric utility business. He retired from his last executive position as the President and CEO of the California Independent System Operator Corporation, a position he held from 2005 to 2011. He previously served in senior executive roles at BC Hydro and British Columbia Transmission Corporation. In 2009, Mr. Mansour was named to the U.S. Department of Energy's Electricity Advisory Committee. He has also served on the North American Electric Reliability Council (NERC), the Canadian National Committee of the international organization CIGRE and the Transmission Council of the Canadian Electric Association. At TransAlta, Mr. Mansour is a member of the Human Resources Committee of the Board. Mr. Mansour, a professional engineer and a Fellow of the Institute of Electrical and Electronics Engineers, is a graduate of the University of Calgary (Calgary, AB) with a master of science and a graduate of the University of Alexandria (Alexandria, Egypt) with a bachelor of science in electrical engineering. He has authored and co-authored numerous publications and is recognized internationally in the field of power engineering.
Dr. Martha C. Piper British Columbia, Canada	2006	***Corporate Director***. Dr. Piper was President and Vice-Chancellor of the University of British Columbia ("UBC") from 1997 to 2006 (education). Prior to her appointment at UBC, she served as Vice-President, Research at the University of Alberta. She served on the boards of the Alberta Research Council, the Conference Board of Canada and the Centre of Frontier Engineering Research. Dr. Piper was also appointed by the Prime Minister of Canada to the Advisory Council on Science and Technology and served as Chair of the Board of the National Institute for Nanotechnology. Dr. Piper is a member of the board of directors of Shoppers Drug Mart and Bank of Montreal. She is also a member of the Canadian delegation to the Trilateral Commission, an organization fostering closer cooperation among the core democratic industrialized areas of the world. She also sits on the boards of Canadian Institute for Advanced Research, Dalai Lama Centre for Peace & Education, CARE Canada and the Canadian Stem Cell Foundation, non-public entities. At TransAlta, Dr. Piper is a member of the Governance and Environment Committee and the Human Resources Committee of the Board. Dr. Piper holds a bachelor of science in physical therapy from the University of Michigan (Ann Arbor, MI), a master of arts in child development from the University of Connecticut (Storrs, CT), and a doctorate of philosophy in epidemiology and biostatistics from McGill University (Montréal, QC). She has also received honorary degrees from 18 international universities. Dr. Piper is an Officer of the Order of Canada and a recipient of the Order of British Columbia.

Notes:

(1) The following nominee directors are Canadian residents: William D. Anderson, Dawn L. Farrell, C. Kent Jespersen, Michael M. Kanovsky, Gordon S. Lackenbauer, Karen E. Maidment and Martha C. Piper.

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

(3) Mr. Jespersen resigned from the Board of Directors of CCR Technologies Ltd. ("CCR") in February 2010. CCR filed with the Court of Queen's Bench of Alberta a proposal dated December 1, 2010 pursuant to provisions of Part III Division I of the *Bankruptcy and Insolvency Act* to restructure and reorganize the financial affairs of CCR, to compromise the claims of the unsecured creditors, restructure the shares of CCR, and to allow it to conduct a restructuring and "rightsizing" of its operations on a going concern basis. This proposal was approved by the unsecured creditors on December 22, 2010 and by the Court on January 13, 2011. The Alberta Securities Commission issued a variation order dated February 14, 2011 to partially revoke its cease trade order to permit the implementation of the proposal which was subsequently implemented.

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

Officers

The name, province or state and country of residence of each of our officers as at February 29, 2012, their respective position and office and their respective principal occupation during the five preceding years, are set out below.

Name	Principal Occupation	Residence
Dawn L. Farrell	President and Chief Executive Officer	Alberta, Canada
William D. A. Bridge	Executive Vice-President, Business Development	Alberta, Canada
Robert (Bob) Emmott	Chief Engineer	Alberta, Canada
Brett Gellner	Chief Financial Officer	Alberta, Canada
Cynthia Johnston	Executive Vice-President, Corporate Services	Alberta, Canada
David J. Koch	Vice-President, Controller	Alberta, Canada
Dawn de Lima	Chief Human Resources Officer and Executive Vice-President, Communications	Alberta, Canada
Maryse C. St.-Laurent	Vice-President and Corporate Secretary	Alberta, Canada
Robert Schaefer	Executive Vice-President, Corporate Development	Alberta, Canada
Joseph Wilfrid Hugo Shaw	Executive Vice-President, Operations	Alberta, Canada
Todd Stack	Treasurer	Alberta, Canada
Kenneth S. Stickland	Chief Legal and Business Development Officer	Alberta, Canada
Paul Taylor	President, U.S. Operations	Olympia, WA, U.S.A.

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

- Prior to January 2012, Mrs. Farrell served as Chief Operations Officer from 2009 to 2011. Prior to April 2009, she was Executive Vice-President, Commercial Operations and Development of the Corporation. Prior to July 2007, she was Executive Vice-President Engineering, Aboriginal Relations and Generation at BC Hydro and prior to June 2006 she was Executive Vice-President Generation.

- Prior to September 2011, Mr. Bridge was Chief Technology Officer & Project Lead Centennial Project. Prior to December 2010, he was Chief Technology Officer. Prior to April 2009, he was Executive Vice-President, Generation Technology and PMM of the Corporation. Prior to July 2007, he was Vice-President, Western Canada Operations.

- Prior to October 2010, Mr. Emmott was Vice-President and Chief Engineer. Prior to February 2009, he was Director, Technical Services and prior to 2008 he was Manager, Technical Services.

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

- Prior to September 2011, Ms. Johnston was Vice-President, Renewable Operations. Prior to December 2009, she was Vice-President Regulatory and Legal with FortisAlberta Inc. from June 2004.

- Prior to May 2011, Mr. Koch was Vice-President, Operations Finance. Prior to November 2010, he was Vice-President, Financial Operations. Prior to December 2006, he was Director, Generation Finance from March 2004.

- Prior to September 2011, Ms. de Lima was Chief Human Resources Officer. Prior to March 2011, she was Vice-President Supply Chain Management and prior to May 2009 she was Vice-President, Corporate HR from November 2007.

- Prior to December 2008, Ms. St.-Laurent was Corporate Secretary of TransAlta.

- Prior to October 2011, Mr. Schaefer was Vice-President, Commercial Operations and Development. Prior to June 2010, he was Vice-President, Development. Prior to June 2008, he was Chief Financial Officer at Resin Systems Inc. from August 2005.

- Prior to October 2011, Mr. Shaw was Vice-President, Coal Operations and Engineering Services. Prior to April 2011, he was Vice-President, Engineering, Environment and Construction. Prior to April 2009, he was Vice-President, Maintenance and Field Engineering & PMO from July 2003.

- Prior to May 2011, Mr. Stack was Assistant Treasurer. Prior to October 2010, he was Director, Treasury Operations. Prior to January 2008, he was Manager, Financial Risk. Prior to January 2006, he was Manager, Corporate Finance.

- Prior to September 2011, Mr. Stickland was Chief Legal Officer. Prior to April 2009, he was Executive Vice-President, Legal, SD and EH&S. Prior to April 2007, he was Executive Vice-President, Legal.

- Prior to September 2011, Mr. Taylor was Leader, Western Growth Strategy. Prior to April 2011, he was Chief of Staff at the Office of the Premier, Government of BC. Prior to June 2010, he was President, CEO and Director of Naikun Wind Energy Group Inc. Prior to September 2008, he was President and Director of Naikun Wind Energy Group Inc. Prior to May 2008, he was President and CEO of Insurance Corporation of British Columbia from October 2004.

As of February 29, 2012, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over an aggregate of 664,515 of our common shares. This constitutes less than one per cent of our outstanding common shares.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of TransAlta, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than ten per cent of our common shares, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving TransAlta within the three most recently completed financial years or to date in 2011 or in any proposed transactions that has materially affected or will materially affect us.

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2011, there has been no indebtedness outstanding to TransAlta from any of our directors, executive officers, senior officers or associates of any such directors, nominees or senior officers.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders

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

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

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

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

Personal Bankruptcies

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

Penalties or Sanctions

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

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

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

CONFLICTS OF INTEREST

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TransAlta is occasionally named as a party in claims and legal proceedings which arise during the normal course of its business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claim may not have a material adverse effect on TransAlta. For further information, please refer to Notes 32 and 35 of our audited consolidated financial statements for the year ended December 31, 2011 which financial statements are incorporated by reference herein. See "Documents Incorporated by Reference" herein.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares and Series A and Series C First Preferred Shares is CIBC Mellon Trust Company in Vancouver, Calgary, Winnipeg, Toronto and Montréal. On November 1, 2010, CIBC Mellon sold its issuer services business to Canadian Stock Transfer Company Inc. which is currently operating the stock transfer business in the name of CIBC Mellon Trust Company during a transition period. The transfer agent and registrar for our common shares in the United States is Computershare at its principal office in Jersey City, New Jersey.

INTERESTS OF EXPERTS

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

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

ADDITIONAL INFORMATION

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

Additional information including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in our Management Proxy Circular for the most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request to our Investor Relations department, or as filed on SEDAR at www.sedar.com.

Additional financial information is provided in our audited consolidated financial statements as at and for the year ended December 31, 2011 and in the related Annual MD&A, each of which is incorporated by reference in this AIF. See "Documents Incorporated by Reference" herein.

AUDIT AND RISK COMMITTEE

General

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

Mandate of the Audit and Risk Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls established by management, iii) the risk identification assessment conducted by management and the programs established by management in response to such assessment, iv) the internal audit function, v) compliance with accounting and finance based legal and regulatory requirements and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and the management of the Corporation.

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

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

The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "*audit committee financial expert*" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on a member of the Committee and Board in the absence of such designation.

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

Audit and Risk Committee Charter

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

Relevant Education and Experience of Audit and Risk Committee Members

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

Name of ARC Member	Relevant Education and Experience
W. D. Anderson	Mr. Anderson is a Chartered Accountant, with 17 years experience with a major Chartered Accountant firm in Canada. Mr. Anderson has served as CEO of a public company and as CFO of several public companies. In such capacities, Mr. Anderson actively supervised persons engaged in preparing, auditing, analyzing or evaluating financial statements. Mr. Anderson has also served as a principal financial officer and accounting officer and as a director and audit committee chair and member of several public companies. He has served on the board and audit committee of a public company that reports under U.S. GAAP.

Name of ARC Member	Relevant Education and Experience
S. L. Baum	Mr. Baum has over 25 years of financial, legal and industry experience gained working as a senior officer, director and chairman of energy companies. During his tenure as CEO of Sempra Energy, Mr. Baum had financial officers reporting directly to him. Mr. Baum also serves as Chairman of the Audit Committee of Computer Sciences Corporation, a NYSE listed company. Mr. Baum holds a law degree from the University of Virginia.
G. S. Lackenbauer	Mr. Lackenbauer has over 35 years of experience in the investment banking industry. Mr. Lackenbauer has also appeared as an expert financial witness with respect to financial markets, capital structure, cost of capital and fair return on common equity, in over 40 regulatory proceedings. Mr. Lackenbauer also has extensive experience as a director or governor of public companies and not for profit organizations. Mr. Lackenbauer holds a bachelor of arts in economics, a master of business administration from the University of Western Ontario and is a Chartered Financial Analyst.
K. E. Maidment	Ms. Maidment is a Chartered Accountant. Ms. Maidment has served as a CFO with financial oversight responsibilities for TSX and NYSE listed public companies for over 15 years. She has also held positions where she was responsible for global finance operations, risk management, legal and compliance, communications and mergers and acquisitions. In addition, Ms. Maidment has worked with government bodies in order to develop regulations and frameworks for the conversion of major insurers from mutual to public companies. Ms. Maidment holds a bachelor of commerce from McMaster University, and in 2000 was named a Fellow of the Institute of Chartered Accountants of Ontario.

Other Board Committees

In addition to the ARC, TransAlta has two other standing committees: the Governance and Environment Committee and the Human Resources Committee. The members of these committees as of December 31, 2011 are:

Governance and Environment Committee	Human Resources Committee
Chair: Michael M. Kanovsky	**Chair: Timothy W. Faithfull**
Gordon S. Lackenbauer	C. Kent Jespersen
Karen E. Maidment	Yakout Mansour
Martha C. Piper	Martha C. Piper

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

Fees Paid to Ernst & Young LLP

For the years ended December 31, 2011 and December 31, 2010, Ernst & Young LLP and its affiliates were paid $3,110,078 and $3,499,254 respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31	2011	2010
Audit Fees	$ 2,725,847	$ 2,737,081
Audit-related fees	384,231	729,873
Tax fees	0	32,300
All other fees	0	0
Total	**$ 3,110,078**	**$ 3,499,254**

No other audit firms provided audit services in 2011 or 2010.

The nature of each category of fees is described below:

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of our annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English to French of our financial statements and other documents. Total audit fees for 2011 include payments related to 2010 in the amount of $894,776. Total audit fees for 2010 include payments related to 2009 in the amount of $969,568.

Audit-Related Fees

The audit-related fees in 2011 were primarily for work performed by Ernst & Young LLP in relation to preferred share issuances, Canadian and US shelf work, the 2010 Sustainability Report review, and miscellaneous accounting advice provided to the Corporation. The audit-related fees in 2010 were primarily for work performed by Ernst & Young LLP in relation to the implementation of IFRS, other audits, public equity and debt offerings and miscellaneous advice provided to the Corporation.

Tax Fees

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

All Other Fees

Nil.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the ARC adopted a policy (the "Policy") that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act. The Policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting. In 2009, the ARC granted management the authority to approve *de minimus* permissible non-audit services (which are in the aggregate the lesser of five per cent of the total fees paid to the external auditors or $125,000) provided such services are reported to the ARC at its next scheduled meeting.

APPENDIX "A"

AUDIT AND RISK COMMITTEE CHARTER

TRANSALTA CORPORATION
(the "Corporation")

A. Establishment of Committee and Procedures

1. Composition of Committee

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

2. Appointment of Committee Members

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

3. Vacancies

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

4. Committee Chair

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

5. Absence of Committee Chair

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

6. Secretary of Committee

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

7. Meetings

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

8. Quorum

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

9. Notice of Meetings

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

10. Attendance at Meetings

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

11. Procedure, Records and Reporting

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

12. Review of Charter and Evaluation of Committee

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

13. Outside Experts and Advisors

The Committee Chair, on behalf of the Committee, or any of its members is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls established by management, iii) the risk identification assessment conducted by management and the programs established by management in response to such assessment, iv) the internal audit function, v) compliance with accounting and finance based legal and regulatory requirements and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and the management of the Corporation.

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

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

The designation of a member or members as an "*audit committee financial expert*" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "*audit committee financial expert*" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on a member of the Committee and Board in the absence of such designation.

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

C. Duties and Responsibilities of the Committee

1. Audit and Financial Matters

A) External Auditors Qualifications

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

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

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

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

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

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

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

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

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

B) *Independent Audit Process*

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

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

Review with management and the external auditors all financial statements and financial disclosure;

(i) recommend to the Board for approval the Corporation's audited annual financial statements including the notes thereto; the "Management's Discussion and Analysis" and any required reconciliation;

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

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

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

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

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

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

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

Review with management and the external auditors the Corporation's interim financial statements, including the notes thereto, "Management's Discussion and Analysis", the related earnings release, and approve their release to the public as required;

Review and discuss with management and the external auditors the use of "pro forma" or "non-comparable" information and the applicable reconciliation;

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

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

C) *Financial Planning*

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

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

(c) Receive regular updates with respect to the Corporation's financial obligations, loans, credit facilities, credit position and financial liquidity.

2. Governance

(a) On behalf of the Committee, the Chair shall review all public disclosure of material financial information extracted or derived from the Corporation's financial statements prior to dissemination to the public;

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

(c) Review quarterly with senior management and the Chief Legal Officer, and as necessary, outside legal advisors, and the Corporation's internal and external auditors, the effectiveness of the Corporation's internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and with the Corporation's policies;

(d) Review quarterly with the Chief Legal Officer, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the Corporation's financial statements;

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

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

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

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

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

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

(k) Review annually the Corporation's annual sponsorship, donations and political contributions;

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

(m) Review disclosure made to the Committee by the CEO, CFO and/or Chief Legal Officer of a material violation of applicable securities laws, a material breach of a fiduciary duty under applicable laws or a similar material violation by the Corporation or by any officer, director,

employee or agent of the Corporation, which has been reported to the Committee, determine whether an investigation is necessary regarding any such report and report to the Board;

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

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

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

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

(r) Report annually to shareholders on the work of the Committee during the year.

3. Internal Audit

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

(b) Review annually the internal audit department's charter, the scope and plans for the work of the internal audit group, the adequacy of the group's resources, the internal auditors' access to the Corporation's records, property and personnel;

(c) Recognize and advise senior management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

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

(e) Review with the Corporation's senior financial management and the Director, Internal Audit the adequacy of the Corporation's systems of internal control and procedures; and

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

4. Risk Management

The Board is responsible for ensuring that the Corporation has adopted processes and key policies for the identification, assessment and management of its principal risks. The Board has delegated to the Committee the responsibility for the oversight of management's identification of the Corporation's principal risks, the evaluation of such risks and the implementation of appropriate policies, processes and systems to manage or mitigate the risks within the Corporation's risk appetite. The Committee reports to the Board thereon.

The Committee shall:

(a) Review, at least quarterly, management's assessment of the Corporation's principal risks; discuss with management the processes for the identification of these risks and the efficacy of the policies and procedures for mitigating and/or addressing these risks;

(b) Receive and review managements' quarterly risk update including an update on residual risks;

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

(d) Review annually the Corporation's Financial and Commodity Exposure Management Policies and approve changes to such policies;

(e) Review and approve the Corporation's strategic hedging program, guidelines and risk tolerance;

(f) Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(g) Review the Corporation's annual insurance program, including the risk retention philosophy, potential exposure and corporate liability protection programs;

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

(i) Annually, together with management, report and obtain the Board's approval with respect to:

(i) the Corporation's principal risks and overall risk appetite/profile;

(ii) the Corporation's strategies in addressing its risk profile;

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

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

D. Compliance and Powers of the Committee

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

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

APPENDIX "B"

GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

Air Emissions – Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury, and greenhouse gases.

Alberta Power Purchase Arrangement (PPA) – A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA Buyers.

Availability – A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler – A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

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

Carbon Capture and Storage (CCS) – An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

Cogeneration – A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Combined-Cycle – An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

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

Dividend – refers to a cash dividend declared payable by TransAlta on the outstanding Shares.

Force Majeure – Literally means "greater force". These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant – A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt – A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh) – A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG) – Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Kilowatt (kW) – A measure of electric power equal to 1,000 watts.

Kilowatt hour (kWh) – A measure of electricity consumtion equivalent to the use of 1,000 watts of power over a period of one hour.

Megawatt (MW) – A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) – A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Net Maximum Capacity (NMC) – The maximum capacity or effective rating, modified for ambient limitations, that generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Supercritical Technology – The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Uprate – To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR) – A measure to manage earnings exposure from energy trading activities.