TransAlta™

essential. engaged. evolving.

Annual Report 2012

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letter to shareholders

As we left 2012, the value of TransAlta's shares had fallen by 28 per cent over the year and the market value of equity fell by approximately 19 per cent. Although we have seen some improvement since January 2013, the 2012 results were not at all what we wanted or what we intend to produce for our shareholders.

Despite these results, 2012 was a year of progress for TransAlta as we repositioned the company for growth and worked to preserve significant value for shareholders going forward. Some of the highlights of our 2012 accomplishments include:

> "I have spent a lot of time over the last few years ensuring our operations team is ready to take full accountability for delivering the base business. They are. My focus now is on growing and continuing to expand our direct customer business.

- Achieving fleet adjusted availability of 90 per cent, a level that is well above the North American Electric Reliability Corporation average availability for plants of our age and size,
- Achieving first quartile safety performance with an incident frequency rate of 0.89,
- Signing a significant cornerstone contract with Puget Sound Energy for output from Centralia Thermal, as well as reducing plant cash costs to ensure Centralia Thermal can compete in an environment of low natural gas and power prices,
- Creating a strategic partnership with MidAmerican Energy Holdings Company (MidAmerican) for natural gas-fired generation development in Canada,
- Acquiring the Solomon power station in Western Australia, adding 125 MW of contracted power to the portfolio and moving us closer to our goal of having 600 MW of behind-the-fence generation in Western Australia by 2015,
- Completing our three-year reinvestment program in our coal fleet and setting it up for solid operations until its end of life,
- Winning two significant force majeure claims, one on our Sundance Units 1 and 2, and one on Sundance 3, both of which validated TransAlta's strong operating practices,
- Uprating our Keephills Units 1 and 2,
- Raising over $1 billion in new capital in the form of preferred shares, common equity, and long-term debt to strengthen the balance sheet, repay short-term debt, and finance the New Richmond wind farm and the acquisition of Solomon in Australia,
- Starting the life extension of our hydro fleet through investing $22 million in a new penstock for the Pocaterra hydro plant,
- Signing 115 MW of new commercial and industrial contracts and renewing 85 per cent of expiring contracts, bringing the total number of direct customers to just over 500 MW – a goal that was accomplished two years ahead of schedule, and
- Realigning the company to ensure a focus on operations and growth while eliminating duplication and cost, which is expected to generate approximately $25 million to $30 million in benefits on an annualized basis.

External events also added value to the company, particularly the federal government's September announcement of the final greenhouse gas (GHG) regulations. As a result of changes in the rules from what was previously proposed, our coal plants can now serve Albertans for an average of 43 years, 3.5 years longer than before. This greatly enhances the value of these assets and provides significant benefits to electricity consumers in the province.

We also had a number of difficult challenges in 2012, including:

- The arbitration panel did not agree with TransAlta's assessment that Sundance 1 and 2 should be economically destroyed. As a result, we had to invest $190 million to rebuild the boilers on both units. We continue to believe that the spirit of the legislation governing the PPAs is meant to ensure that shareholders receive a reasonable rate of return, and that being forced to invest significant capital dollars to keep a PPA intact is unwarranted, despite the ruling of the panel. We will continue to work to ensure that our PPA plants earn reasonable returns through to the end of their PPA terms.
- Our Energy Trading business generated only $3 million in gross margin, the lowest level in its 17-year history and one year after achieving an all-time high. This volatility is unacceptable for the size of our company and we have refocused our strategies to return back to the basics and deliver more consistent results in the range of $40 million to $60 million of gross margin year after year.
- The return of Sundance Units 1 and 2 to the market makes it prudent to delay our plans for Sundance Unit 7. We will continue to advance this investment in 2013, moving forward with permitting efforts as we believe the unit will be needed in the 2018 time frame.
- Lower power pricing in the Pacific Northwest and Alberta markets. Low natural gas prices translate directly into lower power prices, especially in the Pacific Northwest. Above-normal water conditions for the second consecutive year also put downside pressure on spot market power prices due to the large amount of hydro generation and storage in the region. These factors reduced revenues from our Centralia plant.

Financially, all of this translated into delivering $776 million dollars in funds from operations. This is slightly below what we delivered in 2011, despite the pressure on Centralia gross margins due to low power prices and below average results from our Energy Trading business. This level of funds allows us to pay the dividend and reinvest in our current fleet. In terms of the balance sheet, we were very focused on ensuring we maintained our investment grade ratings, and therefore took a number of steps in this regard including issuing preferred shares and common equity, introducing the Premium Dividend™ Reinvestment Program, contracting our assets, and reducing costs.

As we look forward into 2013 and beyond, we see both opportunities and challenges.

My focus for 2013 will be overseeing TransAlta's growth and development. I have spent a lot of time over the last few years ensuring our operations team is ready to take full accountability for delivering the base business. They are. My focus now is on growing and continuing to expand our direct customer business. This will dominate how I spend my time in 2013.

In 2012, our realignment allowed us to define our resources more clearly between base operations and growth. Excellence in operations is a given for TransAlta and it underpins our overall strategy. Our performance is first quartile and our fleet availability continues to outperform North American averages. In 2013, the team will continue to implement best-in-class practices for safety, work management, and management of change. Their dedication to a workplace that is both safe and productive is reflected in our performance in 2012, and by the end of next year we will be able to report even greater progress on our costs and quality initiatives.

In terms of growth, we have excellent teams in place in all of our key markets, and we see tremendous opportunities within them all. The partnership with MidAmerican will allow us to pursue more opportunities than in the past. Our goal is to add between $40 million and $60 million of EBITDA from new growth every year going forward. We are now well positioned to do this.

The upcoming year will also be a big year for our Energy Trading and Marketing team. They have done a terrific job attracting new customers to TransAlta and they will continue that effort. In 2013, their goal is to attract another 600 MW of customers to our business. Our move away from exclusively focusing on wholesale marketing to more direct relationships with wholesale and commercial customers here in Alberta is deliberate. They will return trading back to its historical profitability of $40 million to $60 million in gross margins, which will give us that additional value-added in support of the dividend, our sustaining capital program, and new growth investments.

As always, opportunities can only come with a strong team that is motivated to make the right decisions in both the long and short term. I have spent a significant amount of time with my team and the Human Resources Committee to design a compensation structure that better aligns our incentive pay to achievements in delivering strong funds from operations, free cash flow, and availability. Medium-term incentive pay is aligned to growth in cash flow per share, free cash flow, and total shareholder returns.

I fundamentally believe that we can never lose sight of how financial incentives motivate employees. As we implement this new system in 2013, our staff at TransAlta will have a very clear understanding of how together they can make decisions that will be consistent with short-term and long-term shareholder value creation. The new incentive system – along with our strength in internal communications, our dedication to an open and transparent culture, our commitment to the professional growth of management, technical, and front line staff, and our insistence on a business-centric approach to decision making – will ensure that your team will be one of the strongest in the industry.

Overall, TransAlta's management team worked tremendously hard this past year. The results may not yet be properly reflected in our share price, but their accomplishments contribute to both preserving and growing the future value of TransAlta. I would like to personally thank each member of the team for all they have done. They are more than ready for what 2013 has to bring.

In closing, I would also like to thank the members of our Board of Directors for their patience, guidance, insights and hard work throughout 2012. The Board has your interests at heart by consistently demanding that we take personal accountability for improving our performance. For that I am grateful. I also appreciate the time, counsel, and encouragement that our Chair, Ambassador Gordon Giffin, has given me this year as we've navigated through a very full schedule. Finally, many thanks to both the employees who continue to build their careers here and the employees that we had to say goodbye to in November. Your loyalty, dedication, and spirit make it an honour to represent TransAlta as CEO.

Sincerely,

Dawn Farrell
President and Chief Executive Officer
February 27, 2013

message from the chair

The past year presented many challenges for TransAlta. Some, such as depressed natural gas prices leading to low power prices, are factors your company cannot directly affect. Others, such as regulatory and public policy impacting our business, were addressed by management with commitment and insight. Senior management, led by Dawn Farrell, along with your Board, believes that TransAlta is continuing to develop a solid platform, in challenging times, to succeed going forward.

TransAlta is continuing to diversify the fuel and the geography of its generating fleet, while being innovative and prudent relative to the regulatory regime applicable to its historic coal-fired assets. Dawn Farrell has aligned company management to respond to this new-paradigm era for power generation. The executive team and dedicated employees throughout the organization are focused on building a 21st-century power generator that is sensitive to environmental concerns, committed to efficiently serving its markets, and intent on enhancing shareholder value.

As Chair, I assure you that your Board is engaged and an active partner with management in charting the course for this new era of providing power to markets in North America and Australia. We are not daunted by the challenges and we welcome the opportunity to apply creativity and vision to the future growth of TransAlta. We will continue our practice of employing top governance practices, prudent capital allocation, and industry-leading safety performance, all the while remembering our duty to you, the shareholder.

I look forward to speaking with all of you at our annual meeting.

Sincerely,

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chairman of the Board
February 27, 2013

map of operations

plant summary

As of February 8, 2013	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Fuel	Revenue source	Contract expiry date
Western Canada 39 Facilities	Sundance, AB[2,3]	2,141	100%	2,141	Coal	Alberta PPA/Merchant[4]	2020
	Keephills, AB[5]	792	100%	792	Coal	Alberta PPA/Merchant[5]	2020
	Genesee 3, AB	466	50%	233	Coal	Merchant	–
	Keephills 3, AB	450	50%	225	Coal	Merchant	–
	Sheerness, AB	780	25%	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100%	356	Gas	LTC/Merchant	2024
	Fort Saskatchewan, AB	118	30%	35	Gas	LTC	2019
	Brazeau, AB	355	100%	355	Hydro	Alberta PPA	2020
	Big Horn, AB	120	100%	120	Hydro	Alberta PPA	2020
	Spray, AB	103	100%	103	Hydro	Alberta PPA	2020
	Ghost, AB	51	100%	51	Hydro	Alberta PPA	2020
	Rundle, AB	50	100%	50	Hydro	Alberta PPA	2020
	Cascade, AB	36	100%	36	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100%	19	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100%	17	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100%	15	Hydro	Alberta PPA	2013
	Horseshoe, AB	14	100%	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100%	13	Hydro	Alberta PPA	2020
	Taylor Hydro, AB	13	100%	13	Hydro	Merchant	–
	Interlakes, AB	5	100%	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100%	3	Hydro	Merchant	–
	Three Sisters, AB	3	100%	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100%	3	Hydro	Merchant	–
	St. Mary, AB	2	100%	2	Hydro	Merchant	–
	Upper Mamquam, BC	25	100%	25	Hydro	LTC	2025
	Pingston, BC	45	50%	23	Hydro	LTC	2023
	Bone Creek, BC	19	100%	19	Hydro	LTC	2031
	Akolkolex, BC	10	100%	10	Hydro	LTC	2015
	Summerview 1, AB	70	100%	70	Wind	Merchant	–
	Summerview 2, AB	66	100%	66	Wind	Merchant	–
	Ardenville, AB	69	100%	69	Wind	Merchant	–
	Blue Trail, AB	66	100%	66	Wind	Merchant	–
	Castle River, AB[6]	44	100%	44	Wind	Merchant	–
	McBride Lake, AB	75	50%	38	Wind	LTC	2023
	Soderglen, AB	71	50%	35	Wind	Merchant	–
	Cowley Ridge, AB	21	100%	21	Wind	Merchant	–
	Cowley North, AB	20	100%	20	Wind	Merchant	–
	Sinnott, AB	7	100%	7	Wind	Merchant	–
	Macleod Flats, AB	3	100%	3	Wind	Merchant	–
Total Western Canada		**6,536**		**5,315**			
Eastern Canada 14 Facilities	Sarnia, ON	506	100%	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50%	54	Gas	LTC	2017
	Ottawa, ON	68	50%	34	Gas	LTC	2012
	Windsor, ON	68	50%	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100%	7	Hydro	Merchant	–
	Misema, ON	3	100%	3	Hydro	LTC	2027
	Galetta, ON	2	100%	2	Hydro	LTC	2031
	Appleton, ON	1	100%	1	Hydro	LTC	2031
	Moose Rapids, ON	1	100%	1	Hydro	LTC	2031
	Melancthon, ON	200	100%	200	Wind	LTC	2026-2028
	Wolfe Island, ON	198	100%	198	Wind	LTC	2029
	Kent Hills, NB	150	83%	125	Wind	LTC	2033-2035
	Le Nordais, QC	99	100%	99	Wind	LTC	2033
	New Richmond, QC[7]	68	100%	68	Wind	Quebec PPA	2032
Total Eastern Canada		**1,479**		**1,332**			
United States 17 Facilities	Centralia Thermal, WA	1,340	100%	1,340	Coal	Merchant	–
	Centralia Gas, WA	248	100%	248	Gas	Merchant	–
	Power Resources, TX	212	50%	106	Gas	Merchant	–
	Saranac, NY	240	37.5%	90	Gas	Merchant	–
	Yuma, AZ	50	50%	25	Gas	LTC	2024
	Imperial Valley, CA[8]	327	50%	164	Geothermal	LTC	2016-2029
	Wailuku, HI	10	50%	5	Hydro	LTC	2023
	Skookumchuck, WA	1	100%	1	Hydro	LTC	2020
Total U.S.		**2,428**		**1,979**			
Australia 5 Facilities	Parkeston, WA	110	50%	55	Gas	LTC	2016
	Southern Cross, WA[9]	245	100%	245	Gas/Diesel	LTC	2013
	Solomon Power Station[10]	125	100%	125	Gas/Diesel	LTC	2028
Total Australia		**480**		**425**			
Total		**10,923**		**9,051**			

1 Megawatts are rounded to the nearest whole number.
2 Includes a 15 MW uprate on Sundance Unit 3; the resulting increased capacity will not be realized until the generator stator is replaced.
3 Includes Sundance A expected to be back in service in the fall of 2013 (560 MW).
4 Merchant capacity refers to uprates on Unit 4 (53 MW), Unit 5 (53 MW), and Unit 6 (44 MW).
5 Testing of the Keephills Unit 1 and Unit 2 uprates has been completed and it was determined that the actual capability of the uprates was less than originally anticipated. As a result we have adjusted the uprates to 13 MW, bringing the maximum capability of these units to 396 MW each.
6 Includes seven individual turbines at other locations.
7 Facilities currently under development.
8 Comprised of 10 facilities.
9 Comprised of four facilities.
10 This facility was acquired in September 2012 and was under construction for the remainder of 2012. The plant is expected to be fully commissioned in Q1 of 2013.

management's discussion and analysis

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*This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited 2012 consolidated financial statements and our 2013 Annual Information Form. Our consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises. All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 26, 2013. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including our Annual Information Form, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov**, and on our website at **www.transalta.com**.*

Highlights

Generation Results

- Availability, adjusted for economic dispatching at Centralia Thermal, of our overall fleet increased by almost two per cent from 2011 levels to 90.0 per cent availability despite significantly higher planned major maintenance in 2012.
- Comparable gross margins in Western Canada increased $77 million to $855 million, largely due to the impact of lower Alberta coal Power Purchase Arrangements ("PPAs") penalties due to lower prices in Alberta and higher hydro margins.
- Comparable gross margins in Eastern Canada increased $11 million to $342 million primarily due to lower contracted gas input costs.
- Our International comparable gross margins decreased $43 million to $300 million due to lower merchant pricing, including margins on purchased power.
- Comparable Operations, Maintenance, and Administration ("OM&A") costs have been reduced by $32 million to $381 million due to continued efforts to lower costs and focus on productivity.

Energy Trading Results

- Gross margins decreased by $134 million to $3 million, primarily due to unfavourable market expectations on power and gas prices for our trading positions held.
- OM&A costs decreased by $15 million to $28 million, primarily due to lower compensation costs as a result of lower earnings.

Financial Highlights

- Comparable earnings were $118 million ($0.50 per share), down from $230 million ($1.04 per share) in 2011. The decrease in comparable earnings is primarily due to lower gross margins in Energy Trading. Reported net loss attributable to common shareholders was $614 million ($2.61 per share), down from net earnings of $290 million ($1.31 per share) in 2011, which included the following non-comparable amounts, net of tax:
  - Impairment of $226 million ($347 million pre-tax) at the Centralia Thermal plant and the writeoff of the associated deferred income tax asset of $169 million due to signing a long-term power agreement that will retire the plant in 2025,
  - Impairment of $31 million ($41 million pre-tax) was subsequently reversed as a result of the additional years expected to be realized at Sundance Units 1 and 2 due to amendments to the Canadian federal regulations. Net penalties of $189 million as a result of the arbitration panel concluding that Sundance Units 1 and 2 were not economically destroyed, but meet the criteria of force majeure until they are returned to service,
  - Impairment of $13 million ($18 million pre-tax) related to assets in the renewable fleet,
  - Reversal of a $47 million loss recognized on de-designated hedges primarily at Centralia Thermal,
  - Gain on sale of collateral at MF Global Inc. of $11 million,
  - Income tax recovery of $9 million, and
  - Restructuring charge of $10 million.
- Comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA") decreased $31 million to $1,014 million compared to 2011.
- Funds from operations decreased $33 million to $776 million compared to 2011.
- We have maintained investment grade ratings to support our access to multiple sources of capital.

Progress on Growth Projects through Acquisition and Strategic Partnership

- We completed the acquisition of the 125 megawatt ("MW") natural gas-fired and diesel-fired Solomon power station in Western Australia for $318 million. The power station is fully contracted and is expected to generate pre-financing cash flows of approximately $40 million per year, and is expected to be commissioned during the first half of 2013.
- We have created a new strategic partnership with MidAmerican Energy Holdings Company ("MidAmerican") through which the two companies will work together to develop, build, and operate new natural gas-fueled electricity generation projects in Canada.
- We continue to build our 68 MW New Richmond wind project on the Gaspé Peninsula, which is expected to be commissioned in the first quarter of 2013.

Summary of Results

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

Year ended Dec. 31	2012	2011	2010
Availability (%)[1]	**88.4**	85.4	88.9
Adjusted availability (%)[1,2]	**90.0**	88.2	88.9
Production (GWh)[1]	**38,750**	41,012	48,614
Revenues	**2,262**	2,663	2,673
Gross margin[3]	**1,453**	1,716	1,488
Operating income (loss)[3]	**42**	645	459
Comparable operating income[4]	**470**	553	452
Net earnings (loss) attributable to common shareholders	**(614)**	290	255
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(2.61)**	1.31	1.16
Comparable earnings per share[4]	**0.50**	1.04	0.97
Comparable EBITDA[4]	**1,014**	1,045	963
Funds from operations[4]	**776**	809	805
Funds from operations per share[4]	**3.30**	3.64	3.68
Cash flow from operating activities	**520**	690	852
Free cash flow[4]	**85**	185	172
Dividends paid per common share	**1.16**	1.16	1.16

As at Dec. 31	2012	2011
Total assets	**9,451**	9,729
Total long-term liabilities	**4,726**	4,911

Business Environment

Overview of the Business

We are a wholesale power generator and marketer with operations in Canada, the United States ("U.S."), and Australia. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and utilize a broad range of generation fuels including coal, natural gas, hydro, wind, and geothermal. During 2012, we completed uprates at Keephills Units 1 and 2 and Sundance Unit 3, which we expect will add an additional 41 MW of power to our generation portfolio and increased our total generating capacity to 8,200 MW. Please refer to the Significant Events section of this MD&A for more information. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator.

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

Demand

Demand for electricity is a fundamental driver of prices in all of our markets. Economic growth is the main driver of longer-term changes in the demand for electricity. Historically, demand for electricity in all three of our major markets has grown at an average rate of one to three per cent per year. In recent years, demand growth has been weaker in Ontario and the Pacific Northwest due to economic conditions, while Alberta has shown steady growth.

1 Availability and production includes all generating assets (generation operations, finance leases, and equity investments).
2 Adjusted for economic dispatching at Centralia Thermal.
3 These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of these items.
4 These comparable items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

Alberta has seen annual average demand growth of about three per cent over the past three years. The fourth quarter of 2012 in particular showed a higher growth rate of four per cent on average. Investment in oil sands development is a key driver of electricity demand growth in the province, and several large projects are underway that will bring new demand over the next several years. In the Pacific Northwest and Ontario demand growth was flat in 2012.

Supply

Reserve margins measure available capacity in a market over and above the capacity needed to meet normal peak demand levels. Falling reserve margins indicate that generation capacity is becoming relatively scarce and results in increased power prices. During 2012, reserve margins increased in Ontario and were relatively flat in Alberta and the Pacific Northwest.

Renewable generation growth has been strong in all regions, driven to a varying degree by public policy. The Pacific Northwest has seen a large amount of new wind generation in the last several years, and Ontario is also developing wind and solar capacity through its Feed-in Tariff program. Wind generation in Alberta is also growing rapidly, as over 200 MW of new wind capacity was brought online during 2012, which represents a 26 per cent increase in capacity from the previous year.

Transmission

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

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

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

In 2009, the Government of Alberta declared several important transmission projects as being critical, including lines between the Edmonton and Calgary regions, and between Edmonton and northeast Alberta. In late 2011, the Government of Alberta initiated a review of critical transmission projects. The results of the review by an independent panel were released in early 2012 with the panel recommending proceeding as soon as possible with development of two high-voltage direct current transmission lines between the Edmonton and Calgary regions. In response to the panel recommendations, the provincial government introduced Bill 8 in the Alberta legislature. Bill 8 effectively removes the concept of Critical Transmission Infrastructure ("CTI") from the *Electric Utilities Act*. Existing projects designated as CTI will remain designated as CTI. All new transmission projects will be subject to a needs review by the Alberta Utilities Commission ("AUC"). The CTI projects between Edmonton and northeast Alberta will be subject to a competitive procurement process as set out in the *Electric Statutes Amendment Act*, 2009. The competitive procurement process has been developed by the Alberta Electric System Operator ("AESO") and is currently being considered by the AUC. The AESO has issued a Project Information Brief for the first of two 500 kilovolt alternating current transmission lines that will be subject to a competitive procurement process.

On Nov. 15, 2012, the AUC released its decision approving the Eastern Alberta Transmission Line between the Edmonton and Calgary regions. The decision by the AUC approving a second high-voltage direct current transmission line between the Edmonton and Calgary regions, the Western Alberta Transmission Line, was released on Dec. 6, 2012, albeit with some changes to the preferred route and the use of monopole structures in a 12-kilometre portion of the transmission line.

The existing transmission system is congested and aging, resulting in excessive energy loss and constraints on our generation operations as expected electricity flows exceed the system's current limits. The reinforcement of the transmission system as provided by the two transmission lines will alleviate these constraints, reduce transmission line losses, and allow for the development of additional generation.

Environmental Legislation and Technologies

Environmental issues and related legislation have, and will continue to have, an impact upon our business. Since 2007, we have incurred costs as a result of Greenhouse Gas ("GHG") legislation in Alberta. Please refer to the Climate Change and the Environment section of this MD&A for additional information on the changes to Alberta's GHG legislation that occurred in 2012. Our exposure to increased costs as a result of environmental legislation in Alberta is mitigated through change-in-law provisions in our PPAs. In the State of Washington, the TransAlta Energy Bill (the "Bill") was signed into law and provides a framework to transition from coal to other forms of generation. Legislation in other jurisdictions is in various stages of maturity and sophistication.

While TransAlta discontinued its Pioneer carbon capture and storage project ("Pioneer") in April 2012, the detailed Front-End Engineering Design ("FEED") study that was completed provided us with a comprehensive analysis of this technology, which will provide ongoing value in the assessment of other carbon control strategies. We also are actively and broadly disseminating the knowledge from Pioneer to others who may benefit from it.

Economic Environment

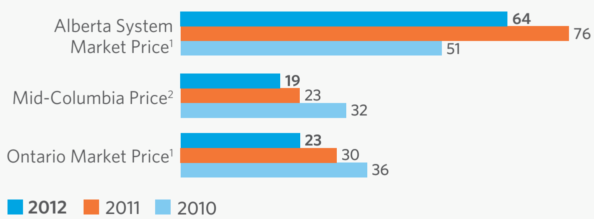
The economic environment showed signs of weakness during 2012 and in 2013 we expect slow to moderate growth in Alberta and Australia, and low growth in other markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

Contracted Cash Flows

During the year, 90 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also entered into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2012 ranging from $60 to $65 per megawatt hour ("MWh") in Alberta, and from U.S.$50 to $55 per MWh in the Pacific Northwest.

Electricity Prices

Average Spot Electricity Prices



1 Cdn$/MWh.
2 U.S.$/MWh.

Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability, economic dispatching, and any contracting strategy. Our Alberta plants, operating under PPAs, receive contracted capacity payments based on targeted availability and will pay penalties or receive payments for production outside targeted availability based upon a rolling 30-day average of spot prices. The PPAs and long-term contracts covering a number of our generating facilities help minimize the impact of spot price changes.

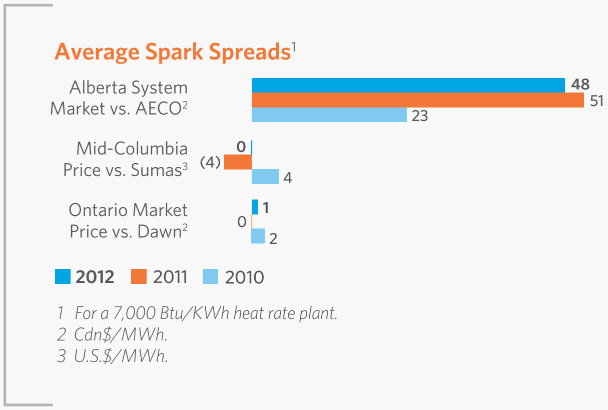
Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, and the other business environment dynamics discussed above. We monitor these trends in prices, and schedule maintenance, where possible, during times of lower prices.

For the year ended Dec. 31, 2012, average spot prices in all three markets decreased compared to the same period in 2011, partially due to lower natural gas prices. In Alberta, spot prices also decreased as a result of overall higher availability. In the Pacific Northwest, spot prices also decreased as a result of increased wind and hydro generation. Spot prices in Ontario also decreased compared to 2011 due to increased supply resulting from facilities returning to service.

In 2013, power prices in Alberta are expected to be lower than 2012 due to fewer planned turnarounds and increased capacity due to additional generation facilities coming online, partially offset by load growth. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, overall prices will still remain weak because of low natural gas prices and slow load growth.

For the year ended Dec. 31, 2011, average spot prices increased in Alberta compared to 2010 due to load growth from the prior year and supply tightening in the market. In the Pacific Northwest and Ontario, average spot prices decreased compared to 2010 due to lower natural gas prices and increased hydro generation in both regions.

Spark Spreads



Spark spreads measure the potential profit from generating electricity at current market rates. A spark spread is calculated as the difference between the market price of electricity and its cost of production. The cost of production is comprised of the total cost of fuel and the efficiency, or heat rate, with which the plant converts the fuel source to electricity. For most markets, a standardized plant heat rate is assumed to be 7,000 British Thermal Units ("Btu") per Kilowatt hour ("KWh").

Spark spreads will also vary between plants due to their design, the geographical region in which they operate, and customer and/or market requirements. The change in the prices of electricity and natural gas, and the resulting spark spreads in our three major markets, affect our Generation and Energy Trading Segments.

For the year ended Dec. 31, 2012, average spark spreads in Alberta decreased compared to the same period in 2011 due to lower power prices. In the Pacific Northwest and Ontario, average spark spreads increased as a result of lower natural gas prices compared to 2011. The decrease in natural gas prices was greater than the decrease in spot prices in both the Pacific Northwest and Ontario, causing the spark spread to increase compared to 2011.

For the year ended Dec. 31, 2011, average spark spreads increased in Alberta compared to 2010 due to higher power prices. In the Pacific Northwest, average spark spreads decreased due to strong hydro generation, which caused power prices to decrease more than natural gas prices compared to 2010. In Ontario, spark spreads decreased as power prices weakened more than natural gas prices compared to 2010.

Strategy

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

Financial Strategy

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

Contracting Strategy

In 2012, we continued to see some demand growth in our Alberta market; however, demand in the Pacific Northwest and Ontario remained flat. While we are not immune to lower power prices, the impact of these lower prices is expected to be mitigated as approximately 85 per cent of 2013 and approximately 78 per cent of 2014 expected capacity across our fleet is contracted. On an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming year. This contracting strategy helps protect our cash flow and our financial position through economic cycles.

Operational Strategy

We manage our facilities to achieve stable and predictable operations that are comparatively low cost and balanced with our fleet availability target. Our target for 2013 is to increase productivity and achieve overall fleet availability of 89 to 90 per cent. Over the last three years, our average adjusted availability has been 89.0 per cent, which is in line with our corporate target.

Growth Strategy

During 2012, we completed efficiency uprates, which we expect will add an additional 26 MW at Keephills Units 1 and 2 and an expected 15 MW at Sundance Unit 3. Please refer to the Significant Events section of this MD&A. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator. During the year we also had 68 MW of wind generation under construction at our New Richmond facility and we completed the acquisition from Fortescue Metals Group Ltd. ("Fortescue") of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia.

Our growth strategy is also focused upon greening and diversifying our portfolio to reduce our carbon footprint and develop long-term, sustainable power generation in our core markets. We continue to explore and selectively develop opportunities for future sustainable power projects.

Capability to Deliver Results

We have the following core competencies and non-capital resources that give us the capability to achieve our corporate objectives. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of the capital resources available that will assist us in achieving our objectives.

Operational Excellence

We seek to optimize our generating portfolio by owning and managing a mix of relatively low-risk assets and fuels to deliver an acceptable and predictable return. Our strategic focus is primarily on improving base operations, repositioning coal, and diversifying our portfolio.

Financial Strength

We manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline will continue to be important during 2013. We continue to maintain $2.0 billion in committed credit facilities, and as of Dec. 31, 2012, $0.8 billion was available to us. Our investment grade credit rating, available credit facilities, funds from operations, and our manageable debt maturity profile provide us with financial flexibility. As a result, we can be selective if and when we go to the capital markets for funding.

The funding required for our growth strategy is supported by our financial strength. In 2012, we took advantage of favourable capital markets by completing the sale of $225 million of Series E Preferred Shares, an offering of U.S.$400 million senior notes, and a public offering of 21.2 million common shares. Looking forward, we expect continued capital market support for projects that meet our return requirements and risk profile.

In the third quarter of 2012, Standard and Poor ("S&P") downgraded our corporate credit rating and senior unsecured debt rating from BBB negative outlook to BBB- stable and our preferred shares from P-3 (high) to P-3. Moody's Investor Services ("Moody's") downgraded our senior unsecured debt rating from Baa2 negative outlook to Baa3 stable. In addition, DBRS placed our unsecured debt rating under review with developing implications.

Following our preferred share offering of 21.2 million common shares, DBRS revised our credit rating back to BBB stable. Participation in the Dividend Reinvestment and Share Purchase ("DRASP") plan continues to be strong and is generating approximately $50 million of new equity on a quarterly basis.

Disciplined Capital Allocation

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

We continue to selectively grow our diversified generating fleet to increase production and meet future demand requirements, with growth projects that have the ability to meet or exceed our targeted rate of return. We currently have 68 MW of wind generation under construction and during the year we completed the acquisition from Fortescue of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia.

People

Our experienced leadership team is made up of senior business leaders who bring a broad mix of skills in the electricity sector, finance, law, government, regulation, engineering, operations, construction, risk management, and corporate governance. The leadership team's experience and expertise, our employees' knowledge and dedication to superior operations, and our entire organization's knowledge of the energy business, in our opinion, has resulted in a long-term proven track record of financial stability. During 2012, we completed a restructuring of our resources as part of our ongoing strategy to continuously improve operational excellence and accelerate growth.

Performance Metrics

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

Availability

1 Adjusted for economic dispatching at Centralia Thermal.

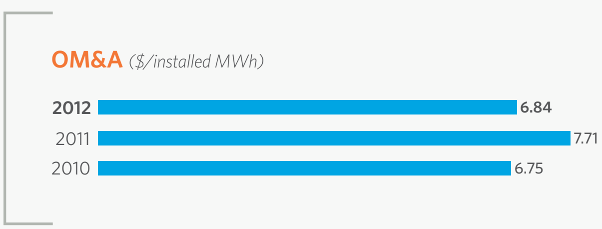
We strive to optimize the availability of our plants throughout the year to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, as well as by reduced production as a result of derates. Our goal is to minimize these events through regular assessments of our equipment and a comprehensive review of our maintenance plans in order to balance our maintenance costs with optimal availability targets. Over the past three years, we have achieved an average adjusted availability of 89.0 per cent, which is in line with our long-term target of 89 to 90 per cent. Our availability in 2012, after adjusting for economic dispatching at Centralia Thermal, was 90.0 per cent (2011 – 88.2 per cent).

For the year ended Dec. 31, 2012, availability increased compared to the same period in 2011 primarily due to lower planned and unplanned outages at Centralia Thermal and lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and at Genesee Unit 3.

Availability for the year ended Dec. 31, 2011 decreased compared to 2010 primarily due to higher planned and unplanned outages at Centralia Thermal and higher unplanned outages at Genesee Unit 3, partially offset by lower planned and unplanned outages at the Alberta coal PPA facilities and lower planned outages at Genesee Unit 3.

The outages at Centralia Thermal did not negatively impact our gross margins for the years ended Dec. 31, 2012 and 2011 as we were able to extend some of our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

Productivity



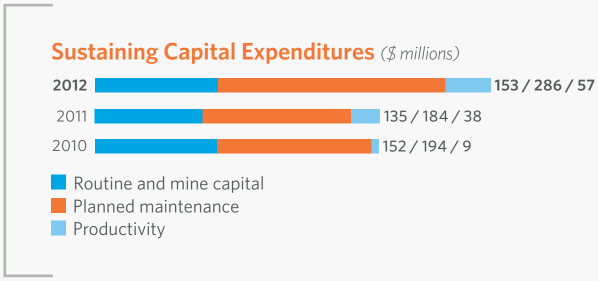
Our OM&A costs reflect the operating cost of our facilities. These costs can fluctuate due to the timing and nature of planned maintenance activities. The remainder of OM&A costs reflects the cost of day-to-day operations. Our target is to offset the impact of inflation in our recurring operating costs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

For the year ended Dec. 31, 2012, OM&A costs per installed MWh decreased compared to 2011 primarily due to lower compensation costs as a result of productivity initiatives and a continued focus on costs.

For the year ended Dec. 31, 2011, OM&A costs per installed MWh increased compared to 2010 due to higher compensation costs associated with favourable results in the Energy Trading Segment, the writeoff of certain wind development costs and costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

Sustaining Capital and Productivity Expenditures

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



In 2012, we spent $139 million more on sustaining capital and productivity expenditures compared to 2011, which was made up of $18 million more on routine and mine capital, $102 million more on planned maintenance, and $19 million more on productivity. The increase in routine and mine capital was due to non-turnaround maintenance projects. Planned maintenance increased primarily due to planned outages at Keephills Units 1 and 2 and Sundance Units 3 and 5. A significant part of the expenditures at the Keephills facility relate to more comprehensive planned major maintenance, including significant component replacements that are not expected to be replaced again over the balance of the life of the plant. Productivity increased as a result of costs associated with several corporate improvement initiatives.

In 2011, we spent $2 million more on sustaining capital and productivity expenditures compared to 2010, which was made up of $29 million more on productivity capital, $17 million less on routine and mine capital, and $10 million less on planned maintenance. The decrease in routine and mine capital was due to lower information technology capital and non-turnaround maintenance costs, as well as a decrease in mine capital due to lower land costs. Planned maintenance decreased primarily due to fewer major coal outages due to the shutdown of Sundance Units 1 and 2, partially offset by higher gas plant outages. The increase in productivity expenditures was primarily due to instrument and controls projects at the Keephills and Sundance facilities, site improvements at our Sundance facility, and the implementation of new software programs.

Safety

Safety is our top priority with all of our staff, contractors, and visitors. Our objective is to maintain our Injury Frequency Rate ("IFR") at less than 1.00 for 2013. Our ultimate goal is to achieve zero injury incidents.

	2012	2011	2010
IFR	**0.89**	0.89	1.19

In 2012, our IFR was consistent with 2011. In 2011, our IFR decreased due to fewer injuries at our Alberta coal facilities, primarily at our Keephills and Sundance facilities. These improvements are a result of continuous efforts to enhance our safety programs through near miss reporting, safety improvement, education, and awareness.

Earnings and Funds from Operations

We focus our base business on delivering strong earnings and funds from operations growth. Our goal is to steadily grow comparable EBITDA, comparable EPS, and funds from operations over the long term, recognizing that the amount of growth may fluctuate year over year with the commodity cycle.

	2012	2011	2010
Comparable EBITDA	**1,014**	1,045	963
Comparable EPS	**0.50**	1.04	0.97
Funds from operations	**776**	809	805
Funds from operations per share	**3.30**	3.64	3.68

In 2012, comparable EPS and comparable EBITDA decreased compared to 2011 primarily due to lower comparable earnings as a result of the decrease in Energy Trading's gross margins. In 2011, comparable EPS and comparable EBITDA increased compared to 2010 primarily due to higher comparable earnings due to strong trading results in the Western regions.

In 2012, funds from operations decreased compared to 2011 due to lower comparable net earnings, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings. In 2011, funds from operations increased compared to 2010 due to higher net earnings.

Investment Grade Ratios

Investment grade ratings support contracting activities and provide better access to capital markets through commodity and credit cycles. We are focused on maintaining a strong financial position and cash flow coverage ratios to support stable investment grade credit ratings.

	2012	2011	2010
Adjusted cash flow to interest coverage *(times)*[1]	**4.4**	4.4	4.6
Adjusted cash flow to debt *(%)*[1]	**18.9**	20.1	19.6
Debt to invested capital *(%)*	**55.7**	52.5	53.1

Adjusted cash flow to interest coverage in 2012 was comparable to 2011. Cash flow to interest coverage decreased in 2011 compared to 2010 primarily due to lower capitalized interest. Our goal is to maintain this ratio in a range of four to five times.

Adjusted cash flow to debt decreased in 2012 compared to 2011 due to higher average debt levels in 2012. Cash flow to debt improved in 2011 compared to 2010 due to lower average debt levels in 2011. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital increased as at Dec. 31, 2012 compared to 2011 due to higher debt levels. Debt to invested capital decreased as at Dec. 31, 2011 compared to 2010 due to lower debt levels and higher net earnings. Our goal is to maintain this ratio in a range of 50 to 55 per cent.

These targets represent a prudent range for the Corporation. At times and over a short-term period, the credit ratios may be outside of the specified target ranges while we realign the capital structure. During 2012, we took several steps to reduce debt, including adding a Premium Dividend™ component to our dividend reinvestment plan and issuing approximately $300 million of common shares and approximately $225 million of preferred shares. In 2013, the dividend reinvestment plan is expected to generate proceeds of approximately $200 million. Please refer to Note 28 of our audited consolidated financial statements within our 2012 Annual Report for additional information regarding the amendments.

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

Shareholder Value

Our business model is designed to deliver low to moderate risk-adjusted sustainable returns and maintain financial strength and flexibility, which enhances shareholder value in a capital-intensive, long-cycle, commodity-based business. Our goal is to grow Total Shareholder Return ("TSR")[2] by achieving a return of eight to ten per cent per year over the long term, with four to five per cent resulting from yield and four to five per cent resulting from growth.

The table below shows our historical performance on this measure:

	2012	2011	2010
TSR *(%)*	**(22.5)**	4.9	(5.0)

While the TSR has been below our target of eight to ten per cent, we continue to focus on delivering strong shareholder returns. We are actively seeking growth opportunities in Western U.S., Western Australia, and Canada, as demonstrated by the Solomon plant acquisition in Western Australia in 2012. We are focused on delivering cash flow to fund the dividend and growth and maintain investment grade credit ratings. We have declared total dividends of $1.16 per share on common shares over the course of the last three years, returning value to shareholders.

1 *Adjusted for the impacts associated with Sundance Units 1 and 2 arbitration.*

2 *This measure is not defined under IFRS. We evaluate our performance and the performance of our business segments using a variety of measures. This measure is not necessarily comparable to a similarly titled measure of another company. TSR is the total amount returned to investors over a specific holding period and includes capital gains, capital losses, and dividends.*

Results of Operations

Our results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading, and Corporate. Some of our accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Some of our critical accounting policies and estimates include: revenue recognition, valuation and useful life of Property, Plant, and Equipment ("PP&E"), financial instruments, decommissioning and restoration provisions, valuation of goodwill, income taxes, and employee future benefits. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further discussion.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant items from the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Financial Position. While individual line items on the Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive Income (Loss) ("AOCI") in the equity section of the Consolidated Statements of Financial Position.

Net Earnings Attributable to Common Shareholders

The primary factors contributing to the change in net earnings attributable to common shareholders for the years ended Dec. 31, 2012 and 2011 are presented below:

Net earnings applicable to common shareholders for the year ended Dec. 31, 2010	255
Increase in Generation comparable gross margins	48
Mark-to-market movements and de-designations – Generation	84
Increase in Energy Trading gross margins	96
Increase in operations, maintenance, and administration costs	(35)
Increase in depreciation and amortization expense	(18)
Increase in gain on sale of assets	16
Decrease in asset impairment charges	11
Increase in net interest expense	(37)
Increase in equity earnings	7
Increase in income taxes expense	(82)
Increase in net earnings attributable to non-controlling interests	(14)
Increase in preferred share dividends	(14)
MF Global Inc. collateral	(18)
Other	(9)
Net earnings attributable to common shareholders for the year ended Dec. 31, 2011	290
Increase in Generation comparable gross margins	45
Mark-to-market movements and de-designations – Generation	(199)
Decrease in Energy Trading gross margins	(134)
Decrease in operations, maintenance, and administration costs	52
Increase in depreciation and amortization expense	(27)
Decrease in gain on sale of assets	(13)
Increase in asset impairment charges	(307)
Increase in inventory writedown, net of consumption	(19)
Increase in restructuring charges	(13)
Increase in net interest expense	(27)
Decrease in equity income	(29)
Impact of Sundance Units 1 and 2 arbitration	(254)
Increase in preferred share dividends	(16)
MF Global Inc. collateral	33
Other	4
Net loss attributable to common shareholders for the year ended Dec. 31, 2012	**(614)**

For the year ended Dec. 31, 2012, Generation comparable gross margins, excluding the impact of mark-to-market movements, increased compared to the same period in 2011 primarily due to the impact of lower Alberta coal PPA penalties due to lower prices in Alberta, higher hydro margins, and lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3, unfavourable coal costs, and market curtailments.

In 2011, Generation comparable gross margins, excluding the impact of mark-to-market movements, increased compared to 2010 primarily due to higher hydro margins, the commencement of commercial operations of Keephills Unit 3 in 2011, higher wind volumes, lower planned and unplanned outages at the Alberta coal PPA facilities, and lower planned outages at Genesee Unit 3, partially offset by lower recoveries from the Poplar Creek base plant that we no longer operate, the sale of the Meridian facility, the impact of higher Alberta coal PPA penalties due to higher prices in Alberta during outages, the decommissioning of Wabamun, and higher unplanned outages at Genesee Unit 3. The lower recoveries at the Poplar Creek base plant were offset by lower OM&A costs.

Mark-to-market movements decreased for the year ended Dec. 31, 2012 compared to the same period in 2011 due to the recognition of higher mark-to-market gains in 2011 resulting from certain power hedging relationships being deemed ineffective. Included in these gains are amounts that are adjusted as a non-comparable item. Please refer to the Non-IFRS Measures section of this MD&A for further discussion.

In 2011, mark-to-market movements increased compared to 2010 due to the recognition of unrealized gains resulting from certain hedges being deemed ineffective for accounting purposes and increased weakening in market prices in the Pacific Northwest relative to our hedged prices.

For the year ended Dec. 31, 2012, Energy Trading gross margins decreased compared to the same period in 2011 primarily due to the impact of unexpected weather patterns, plant outages, and unfavourable market expectations on power and gas pricing for trading positions held.

In 2011, Energy Trading gross margins increased compared to 2010 primarily due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from lower pricing.

OM&A costs for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 primarily due to lower compensation costs as a result of productivity initiatives and a continued focus on costs.

In 2011, OM&A costs increased compared to 2010 due to higher compensation costs primarily associated with favourable results in the Energy Trading Segment, the writeoff of certain wind development costs and costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

For the year ended Dec. 31, 2012, depreciation and amortization expense increased compared to 2011 primarily due to an increased asset base, largely due to the commencement of commercial operations at Keephills Unit 3, and asset retirements, partially offset by a reduction in depreciation expense due to a lower depreciable asset base caused by asset impairments and the change in the economic useful lives of Alberta coal-fired plants.

In 2011, depreciation expense increased compared to 2010 primarily due to an increased asset base, the impact of the 2010 decrease in Wabamun decommissioning and restoration costs, and the writedown of capital spares, partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Gain on sale of assets for the year ended Dec. 31, 2012 decreased compared to 2011 due to the sale of our Meridian and Grande Prairie facilities and other development projects in 2011.

In 2011, the gain on sale of assets increased compared to 2010 due to the sale of the Meridian gas facility and the Grande Prairie biomass facility, and other development projects.

Asset impairment charges for the year ended Dec. 31, 2012 increased compared to 2011 due to impairment charges related to Centralia Thermal and our renewables fleet recorded in 2012. Refer to the Asset Impairment Charges section of this MD&A for further discussion.

In 2011, asset impairment charges decreased compared to 2010 due to impairment charges related to Sundance Units 1 and 2 and the Meridian facility recorded in 2010.

The inventory writedown recorded in the year ended Dec. 31, 2012 was due to a $44 million net writedown of coal inventories resulting from de-designation of the hedges at the Centralia Thermal plant and the continued low price environment in the Pacific Northwest. The de-designation prevents us from including these contracts as part of the calculation of the net recoverable amount of the inventory. A $36 million benefit for the year ended Dec. 31, 2012, reflected in Generation gross margins, resulted from the consumption of previously written down inventories. Of this amount, $25 million is considered non-comparable as it relates to inventory that was on hand when the hedges were initially de-designated.

Restructuring charges of $13 million were incurred in 2012 due to a restructuring of our resources that is expected to result in a net reduction of approximately 165 positions as part of our ongoing strategy to continuously improve operational excellence and accelerate growth.

For the year ended Dec. 31, 2012, net interest expense increased compared to 2011 primarily due to lower capitalized interest.

In 2011, net interest expense increased compared to 2010 due to lower capitalized interest, lower interest income related to the resolution of certain outstanding tax matters in 2010, and higher interest rates, partially offset by favourable foreign exchange rates and lower debt levels.

For the year ended Dec. 31, 2012, equity income decreased compared to the same period in 2011 due to higher unplanned outages and unfavourable pricing at CE Generation, LLC ("CE Gen").

In 2011, equity income increased compared to 2010 primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

During the second quarter of 2012, results of the Sundance Units 1 and 2 arbitration were released and recorded. Refer to the Significant Events section of this MD&A for further discussion.

In 2011, income tax expense increased compared to 2010 due to higher earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The preferred share dividends for the year ended Dec. 31, 2012 increased compared to 2011 due to a higher balance of preferred shares outstanding during 2012. Additional preferred shares were issued in the fourth quarter of 2011 and the third quarter of 2012.

In 2011, the preferred share dividends increased compared to 2010 due to a higher balance of preferred shares outstanding during 2011. Preferred shares were issued in the fourth quarter of 2010.

In 2011, a reserve on collateral was taken related to collateral on hand at MF Global Inc. due to the uncertainty of collecting of the collateral. During 2012, we sold our claim against MF Global Inc. pertaining to the return of collateral, resulting in a gain. Refer to the Significant Events section of this MD&A for further discussion.

Significant Events

Our consolidated financial results include the following significant events:

2012

Sundance Unit 3

On June 7, 2010, an outage occurred at Unit 3 of our Sundance facility due to the mechanical failure of critical generator components, which resulted in the Unit operating at a reduced capacity level. In response to the event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. The claim was disputed by the PPA Buyers. Due to the uncertainty of the resolution of the dispute, we accrued a provision, representing the potential penalties that may be required to be paid to the PPA Buyers.

The matter was heard before an arbitration panel during the third quarter of 2012. On Nov. 23, 2012, the arbitration panel concluded that a HILP event occurred and our claim for force majeure relief was affirmed. We have reversed a portion of the provision and, as a result, recognized $9 million in revenues.

During the fourth quarter of 2012, the uprate at Sundance Unit 3 was completed. The total cost of the project is estimated at $25 million and it is expected that a 15 MW efficiency uprate will be achieved at the facility. Although we completed the uprate, the resulting increased capacity will not be realized until we replace the generator stator.

Senior Notes Offering

On Nov. 7, 2012, we completed our offering of U.S.$400 million senior notes maturing in 2022 and bearing an interest rate of 4.5 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

Corporate Restructuring

On Oct. 30, 2012, we announced a restructuring of our resources as part of our ongoing strategy to continuously improve operational excellence and accelerate growth. As part of this restructuring, we incurred a one-time pre-tax charge of $13 million.

Strategic Partnership

On Oct. 25, 2012, TransAlta and MidAmerican entered into a new strategic partnership through which the two companies will work together to develop, build, and operate new natural gas-fired electricity generation projects in Canada. The agreement also encompasses our proposed Sundance 7 project. All development and construction, or acquisition, of approved projects will be funded equally by each partner and it is expected that TransAlta will be responsible for construction management, operations, and maintenance of projects that proceed.

Sale of Common Shares

On Sept. 13, 2012, we completed our public offering of 19.2 million common shares and on Sept. 20, 2012, the underwriters exercised in part their over-allotment option to purchase 2.0 million common shares, all at a price of $14.30 per common share, which resulted in total gross proceeds of $304 million. The proceeds of the offering were used to partially fund the acquisition of the Solomon power station in Australia, to fund the construction of our 68 MW New Richmond wind project, repay short-term debt, and for general corporate purposes.

Acquisition of Solomon Power Station

On Sept. 28, 2012, we announced that we completed the acquisition from Fortescue of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility is currently under construction and is expected to be commissioned during the first half of 2013. The facility is fully contracted with Fortescue under a long-term Power Purchase Agreement ("Agreement") with an initial term of 16 years, which commenced in October 2012, after which Fortescue will have the option to either extend the Agreement by an additional five years under the same terms or to acquire the facility. The facility and associated Agreement is accounted for as a finance lease with TransAlta being the lessor.

Sundance Unit 6

On Aug. 18, 2011, the Sundance Unit 6 Generator Step-Up Transformer was damaged as a result of a fire. We gave notice and claimed force majeure relief under the PPA. We have been refunded the penalties that were paid during the outage, a portion of which had previously been provided for, resulting in a net charge of $18 million in net earnings. During the third quarter of 2012, the PPA Buyer informed us that they will be taking the matter to arbitration.

MF Global Inc.

In 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. During 2011, a reserve of U.S.$18 million was taken on the collateral when the parent company of MF Global Inc. filed for bankruptcy protection. During 2012, we sold our claim against MF Global Inc. pertaining to the return of U.S.$36 million of collateral that we had posted, for net proceeds of U.S.$33 million. As a result, a pre-tax gain of $15 million ($11 million after tax) was realized in 2012.

Reversal of Asset Impairment Charges

During the third quarter, we reversed $41 million of pre-tax impairment losses previously taken on Sundance Units 1 and 2. The reversal arose as a result of the additional years of merchant operations expected to be realized at Units 1 and 2 due to the recent amendments to Canadian federal regulations. Please refer to the Change in Economic Useful Life section below for additional information.

Change in Economic Useful Life

As a result of amendments to Canadian federal GHG regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation, we have reviewed the useful lives of our Alberta coal-fired generating facilities and related coal mining assets and where permitted under the regulations, extended the useful lives to a maximum of 50 years. The previous draft regulations proposed shutdown after 45 years. As a result, pre-tax depreciation expense was reduced by $12 million for the year ended Dec. 31, 2012 and is expected to be reduced by $23 million annually thereafter. Please refer to the Climate Change and the Environment section of this MD&A for additional information.

Sale of Preferred Shares

On Aug. 10, 2012, we completed our public offering of 9.0 million Series E 5.0 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $225 million. The proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation.

Centralia Thermal

On July 25, 2012, we announced that we entered into an 11-year agreement to provide electricity from the Centralia Thermal plant to Puget Sound Energy ("PSE"). The contract begins in 2014 and runs until 2025 when the plant is scheduled to be shut down under the Bill that was signed on Dec. 23, 2011. Under the agreement, PSE will buy 180 MW of firm, base-load power starting in December 2014. In December 2015, the contract increases to 280 MW and from December 2016 to December 2024, the contract is for 380 MW. In the last year of the contract, the contracted volume is 300 MW. The agreement was approved, with conditions, by the Washington Utilities and Transportation Commission ("WUTC") on Jan. 9, 2013. On Jan. 23, 2013, it was announced that PSE has filed a petition for reconsideration of certain conditions within the decision issued by the WUTC. On Feb. 5, 2013, the WUTC granted a 30-day extension to the petition and indicated that it would issue its decision on the petition no later than March 29, 2013.

Centralia Coal Inventory Writedown

During the year, we recognized a pre-tax writedown of $44 million related to the coal inventory at our Centralia plant. The writedown is recognized when prices indicate we cannot recover the cost of that inventory.

Of the inventory writedown, $25 million relates to inventory on hand when we de-designated the hedges at Centralia Thermal. During the year, a pre-tax comparable earnings adjustment of $25 million was recognized to offset the effect of this writedown. This adjustment was subsequently reversed as the related inventory was consumed during the year. Please refer to the Non-IFRS Measures section of this MD&A.

Sundance Units 1 and 2

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

The matter was heard before an arbitration panel during the second quarter of 2012. On July 20, 2012, the arbitration panel concluded that Units 1 and 2 were not economically destroyed and the units are being restored to service. The panel affirmed, however, that the event met the criteria of force majeure beginning Nov. 20, 2011 and until such time as the units are returned to service. We recorded penalties net of capacity payments, impairment on the units, and interest. The pre-tax earnings impact recorded during 2012 was $254 million.

The cost to repair the units is estimated at approximately $190 million. This investment is expected to start generating cash flow in the fourth quarter of 2013.

Keephills Units 1 and 2 Uprates

Testing of the Keephills Units 1 and 2 uprates has been completed and it was determined that the actual capability of the uprates was less than originally anticipated. As a result we have adjusted the uprates to 13 MW bringing the maximum capability of these units to 396 MW each. The total costs of the projects are estimated at $51 million.

Project Pioneer

On April 26, 2012, Project Pioneer's industry partners announced they would not proceed with the joint carbon capture and storage ("CCS") project. Project Pioneer was a joint effort by TransAlta, the Capital Power Corporation ("Capital Power"), Enbridge Inc., and the federal and provincial governments to demonstrate the commercial-scale viability of CCS technology.

The first step of the project was to prove the technical and economic feasibility of CCS through a FEED study before making any major capital commitments. Following the conclusion of the FEED study, the industry partners determined that although the technology works and capital costs were in line with expectations, the revenue from carbon sales and the price of emissions reductions were insufficient to allow the project to proceed. The impact of the cancellation of the project is not expected to be material for our 2012 results.

Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "Plan")

On Feb. 21, 2012, we added a Premium Dividend™ Component to our existing DRASP plan. The amended and restated plan provides our eligible shareholders 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) to receive the equivalent to 102 per cent of the dividends payable in cash, the 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 per quarter. The applicable discount under the OCP Component is determined from time to time by the Board and is currently set at three per cent.

2011

Sale of Preferred Shares

On Nov. 30, 2011, we completed our public offering of 11.0 million Series C 4.60 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $275 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Genesee Unit 3 Outage

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

Keephills Unit 3

On Sept. 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.

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 deal closed on Oct. 1, 2011. As a result, we realized a pre-tax gain of $9 million in the fourth quarter of 2011.

President and Chief Executive Officer

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

Sale of Meridian

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. On April 1, 2011, TA Cogen closed the sale of its interest in the Meridian facility. The sale was effective Jan. 1, 2011. As a result, we realized a pre-tax gain of $3 million during the second quarter of 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 first quarter of 2013.

Change in Estimated Residual Values

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

2010

Allocation of Consideration Transferred Adjustment

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

Resolution of Tax Matters

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

Sale of Preferred Shares

On Dec. 10, 2010, we completed our public offering of 12.0 million Series A 4.60 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $300 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Kent Hills 2

On Nov. 21, 2010, the 54 MW expansion of our Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised its 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. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

Ardenville

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

Sundance Unit 3 Uprate

On Sept. 13, 2010, we obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of our Sundance facility. The total capital cost of the project is estimated to be $27 million and was completed during the fourth quarter of 2012. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed Chief Financial Officer, succeeding Brian Burden, who retired from the Corporation.

Dividend Reinvestment and Share Purchase

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

Decommissioning of Wabamun Plant

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

Senior Notes Offering

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

Summerview 2

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

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

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

Discussion of Segmented Results

Generation: Owns and operates hydro, wind, natural gas-fired and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support.

For more information on the strategic partnership that we recently entered into with MidAmerican, please refer to the Significant Events section of this MD&A. MidAmerican also owns a 50 per cent interest in CE Gen and Wailuku Holding Company, LLC. We are also involved in various joint venture projects with Stanley Power Inc. ("Stanley Power"), Capital Power, ENMAX Corporation ("ENMAX"), Nexen Inc. ("Nexen"), and Brookfield Asset Management Inc. ("Brookfield"). Stanley Power owns the minority interest in TA Cogen. The Capital Power joint venture provided the opportunity for us to acquire 50 per cent ownership in the 466 MW Genesee Unit 3 project, as well as to build the Keephills Unit 3 project. ENMAX and our Corporation each own 50 per cent of the McBride Lake wind project. Nexen and our Corporation each have a 50 per cent ownership in the Soderglen wind project. Brookfield owns the other 50 per cent interest in our Pingston hydro facility.

Our interest in the Fort Saskatchewan generating facility and the Solomon power station are accounted for as finance leases and our interests in the CE Gen and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures are accounted for using the equity method. Accordingly, the related operational and financial results of these facilities are no longer included in the results of our Western Canada and International geographical regions, respectively. Although these assets no longer contribute to the operating income of the Generation Segment for accounting purposes, it is management's view that these facilities still form part of our Generation Segment. Refer to the Finance Leases and Equity Investments sections of the Generation Segment discussion of this MD&A for further details.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Canadian and U.S. markets.

Generation Operations

At Dec. 31, 2012, Generation Operations had 8,200 MW of gross generating capacity[1] in operation (7,858 MW net ownership interest) and 68 MW (net ownership interest) under construction and 560 MW under restoration in the Sundance Units 1 and 2 major project. The following information excludes assets that are accounted for as a finance lease or using the equity method, which are discussed separately within the discussion of the Generation Segment. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary.

During 2012, we completed uprates at Keephills Units 1 and 2, which we expect will add an additional 26 MW of capacity at these plants. We also completed the uprate at Sundance Unit 3, which will add an expected 15 MW capacity at this facility. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator. Refer to the Significant Events section of this MD&A for further discussion of these items.

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

The results of Generation Operations are as follows:

Year ended Dec. 31	2012				2011		2010	
	Total	**Comparable adjustments**[1]	**Comparable total**[1]	**Per installed MWh**	Comparable total	Per installed MWh	Comparable total	Per installed MWh
Revenues	**2,259**	**72**	**2,331**	**32.36**	2,399	33.94	2,589	34.26
Fuel and purchased power	**809**	**25**	**834**	**11.58**	947	13.40	1,185	15.68
Gross margin	**1,450**	**47**	**1,497**	**20.78**	1,452	20.54	1,404	18.58
Operations, maintenance, and administration	**384**	**(3)**	**381**	**5.29**	413	5.84	424	5.61
Depreciation and amortization	**489**	**-**	**489**	**6.79**	456	6.45	443	5.86
Asset impairment charges	**324**	**(324)**	**-**	**-**	-	-	-	-
Inventory writedown	**44**	**(25)**	**19**	**0.26**	-	-	-	-
Restructuring charges	**5**	**(5)**	**-**	**-**	-	-	-	-
Taxes, other than income taxes	**27**	**-**	**27**	**0.37**	27	0.38	27	0.36
Intersegment cost allocation	**13**	**-**	**13**	**0.18**	8	0.11	5	0.07
Operating income	**164**	**404**	**568**	**7.89**	548	7.76	505	6.68
Installed capacity *(GWh)*	**72,028**		**72,028**		70,681		75,559	
Production *(GWh)*	**36,700**		**36,700**		38,911		46,416	
Availability *(%)*	**88.1**		**88.1**		84.8		88.5	

Generation Operations Production and Comparable Gross Margins[1]

Generation's production volumes, comparable revenues[1], comparable fuel and purchased power costs[1], and comparable gross margins based on geographical regions and fuel types are presented below.

Year ended Dec. 31, 2012	Production *(GWh)*	Installed *(GWh)*	Comparable revenues	Comparable fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	**20,265**	**28,168**	**985**	**439**	**546**	**34.97**	**15.59**	**19.38**
Gas	**2,558**	**3,128**	**116**	**22**	**94**	**37.08**	**7.03**	**30.05**
Renewables	**3,453**	**11,748**	**226**	**11**	**215**	**19.24**	**0.94**	**18.30**
Total Western Canada	**26,276**	**43,044**	**1,327**	**472**	**855**	**30.83**	**10.97**	**19.86**
Gas	**3,835**	**6,588**	**370**	**166**	**204**	**56.16**	**25.20**	**30.96**
Renewables	**1,486**	**5,802**	**145**	**7**	**138**	**24.99**	**1.21**	**23.78**
Total Eastern Canada	**5,321**	**12,390**	**515**	**173**	**342**	**41.57**	**13.96**	**27.61**
Coal	**3,736**	**11,780**	**367**	**150**	**217**	**31.15**	**12.73**	**18.42**
Gas	**1,367**	**4,814**	**122**	**39**	**83**	**25.34**	**8.10**	**17.24**
Total International	**5,103**	**16,594**	**489**	**189**	**300**	**29.47**	**11.39**	**18.08**
	36,700	**72,028**	**2,331**	**834**	**1,497**	**32.36**	**11.58**	**20.78**

1 *Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.*

Year ended Dec. 31, 2011	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	21,475	26,846	863	379	484	32.15	14.12	18.03
Gas	2,588	3,282	118	33	85	35.95	10.05	25.90
Renewables	3,237	11,645	220	11	209	18.89	0.94	17.95
Total Western Canada	27,300	41,773	1,201	423	778	28.75	10.13	18.62
Gas	3,578	6,570	410	219	191	62.40	33.33	29.07
Renewables	1,521	5,790	147	7	140	25.39	1.21	24.18
Total Eastern Canada	5,099	12,360	557	226	331	45.06	18.28	26.78
Coal	5,135	11,742	520	261	259	44.29	22.23	22.06
Gas	1,377	4,806	121	37	84	25.18	7.70	17.48
Total International	6,512	16,548	641	298	343	38.74	18.01	20.73
	38,911	70,681	2,399	947	1,452	33.94	13.40	20.54

Year ended Dec. 31, 2010	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	25,025	31,325	813	331	482	25.95	10.57	15.38
Gas	3,493	4,246	222	76	146	52.28	17.90	34.38
Renewables	2,506	11,120	142	10	132	12.77	0.90	11.87
Total Western Canada	31,024	46,691	1,177	417	760	25.21	8.93	16.28
Gas	3,816	6,570	435	243	192	66.21	36.99	29.22
Renewables	1,330	5,435	126	7	119	23.18	1.29	21.89
Total Eastern Canada	5,146	12,005	561	250	311	46.73	20.82	25.91
Coal	8,594	12,057	730	469	261	60.55	38.90	21.65
Gas	1,652	4,806	121	49	72	25.18	10.20	14.98
Total International	10,246	16,863	851	518	333	50.47	30.72	19.75
	46,416	75,559	2,589	1,185	1,404	34.26	15.68	18.58

Western Canada

Our Western Canada assets consist of five coal plants, one natural gas-fired facility, 21 hydro facilities, and 11 wind farms, with a total gross generating capacity of 4,900 MW (4,705 MW net ownership interest).

Our Sundance, Keephills Units 1 and 2, and Sheerness plants, and 13 hydro facilities with gross generating capacity of 4,109 MW (3,914 MW net ownership interest) operate under PPAs. Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability, and an excess energy payment for power production above committed capacity. Additional capacity added to these units that is not included in capacity covered by the PPAs is sold on the merchant market.

Genesee Unit 3, Keephills Unit 3, a portion of Poplar Creek and Castle River, four hydro facilities, and ten additional wind farms sell their production on the merchant spot market. To manage our exposure to changes in spot electricity prices as well as capture value, we contract a portion of this production to guarantee cash flows.

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

For the year ended Dec. 31, 2012, production decreased 1,024 gigawatt hours ("GWh") compared to 2011, primarily due to higher planned outages at the Alberta coal PPA facilities and lower PPA customer demand, partially offset by the commencement of commercial operations at Keephills Unit 3, lower unplanned outages at the Alberta coal PPA facilities, and higher hydro volumes.

In 2011, production decreased 3,724 GWh compared to 2010, primarily due to the shutdown at Sundance Units 1 and 2, the sale of the Meridian facility, and the decommissioning of Wabamun, partially offset by the commencement of commercial operations of Keephills Unit 3, lower planned and unplanned outages at the Alberta coal PPA facilities, higher wind volumes, and higher hydro volumes.

Comparable gross margin for the year ended Dec. 31, 2012 increased $77 million ($1.24 per installed MWh) compared to 2011, primarily due to favourable pricing, higher hydro margins, the commencement of commercial operations at Keephills Unit 3, and lower unplanned outages at Alberta coal PPA facilities, partially offset by higher planned outages at Alberta coal PPA facilities and unfavourable coal pricing.

In 2011, comparable gross margin increased $18 million ($2.34 per installed MWh) compared to 2010, primarily due to higher hydro margins and the commencement of commercial operations at Keephills Unit 3, partially offset by the discontinuation of managing the base plant at Poplar Creek. The lower recoveries at the Poplar Creek base plant were offset by lower OM&A costs.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities, five hydro facilities, and four wind farms, with a total gross generating capacity of 1,411 MW (1,264 MW net ownership interest). All of our assets in Eastern Canada earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Our Windsor facility also sells a portion of its production on the merchant spot market.

For the year ended Dec. 31, 2012, production increased 222 GWh compared to 2011, due to favourable market conditions at natural gas-fired facilities, partially offset by lower wind volumes.

In 2011, production decreased 47 GWh compared to 2010, due to higher outages and unfavourable market conditions at natural gas-fired facilities, partially offset by higher wind volumes.

Gross margin for the year ended Dec. 31, 2012 increased $11 million ($0.83 per installed MWh) compared to 2011, primarily due to favourable contracted gas input costs, partially offset by lower wind volumes.

In 2011, gross margin increased $20 million ($0.87 per installed MWh) compared to 2010, primarily due to higher wind volumes at a higher price per installed MWh.

International

Our International assets consist of natural gas, coal, and hydro assets in various locations in the United States with a generating capacity of 1,589 MW and natural gas-fired and diesel-fired assets in Australia with a generating capacity of 300 MW.

Our Centralia Thermal, Centralia Gas, and Skookumchuck facilities are merchant. To reduce the volatility and risk in merchant markets, we use a variety of physical and financial hedges to secure prices received for electrical production. The remainder of our International facilities operate under long-term contracts.

For the year ended Dec. 31, 2012, production decreased 1,409 GWh compared to 2011, primarily due to higher economic dispatching at Centralia Thermal, partially offset by lower planned and unplanned outages at Centralia Thermal. The outages at Centralia did not negatively impact our gross margins for the year ended Dec. 31, 2012 as we were able to extend some of our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

In 2011, production decreased 3,734 GWh compared to 2010, primarily due to higher planned and unplanned outages and higher economic dispatching at Centralia Thermal. The outages at Centralia did not negatively impact our gross margins for the year ended Dec. 31, 2011 as we were able to extend some of our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

For the year ended Dec. 31, 2012, comparable gross margin decreased $43 million ($2.65 per installed MWh) compared to 2011, primarily due to unfavourable pricing, including margins on purchased power.

In 2011, comparable gross margin increased $10 million ($0.98 per installed MWh) compared to 2010, primarily due to favourable pricing primarily driven by lower purchased power prices.

During 2012, unrealized pre-tax gains of $90 million (2011 – $207 million gain, 2010 – $43 million gain), related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes, were released from AOCI and recognized in earnings. The cash flow hedges were in respect of future power production expected to occur during 2012 and 2013. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices.

These unrealized gains were calculated using current forward prices that will change between now and the time the contracts will be settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings in the period in which they settle, the majority of which occurred during 2012. As these gains have already been recognized in net earnings in the current and prior periods, future reported earnings will be lower; however, the expected cash flows from these contracts will not change.

Operations, Maintenance, and Administration Expense

For the year ended Dec. 31, 2012, comparable OM&A costs decreased $32 million compared to 2011, primarily due to lower compensation costs as a result of productivity initiatives and a continued focus on costs.

In 2011, comparable OM&A costs decreased $11 million compared to 2010, due to lower costs associated with the discontinuation of managing the base plant at Poplar Creek, partially offset by costs associated with several productivity initiatives and the commencement of commercial operations of Keephills Unit 3.

Planned Maintenance

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

Year ended Dec. 31	2012	2011	2010
Capitalized	**286**	184	194
Expensed	**–**	2	3
	286	186	197
GWh lost	**4,186**	2,872	2,739

Our planned major maintenance program relates to regularly scheduled major maintenance activities and includes costs related to inspection, repair and maintenance, and replacement of existing components. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

For the year ended Dec. 31, 2012, total planned maintenance costs increased $100 million compared to 2011, due to higher planned outages at our Alberta coal PPA facilities. In 2012, production lost as a result of planned maintenance increased 1,314 GWh compared to 2011, primarily due to higher planned outages at our Alberta coal PPA facilities.

In 2011, total planned maintenance costs decreased $11 million compared to 2010, due to fewer major coal outages due to the shutdown of Sundance Units 1 and 2, partially offset by higher gas plant outages. In 2011, production lost as a result of planned maintenance increased 133 GWh compared to 2010, primarily due to higher planned outages at natural gas-fired facilities.

Depreciation Expense

For the year ended Dec. 31, 2012, depreciation expense increased $33 million compared to 2011, due to an increased asset base, largely due to the commencement of commercial operations at Keephills Unit 3, and asset retirements, partially offset by a reduction in depreciation expense due to a lower depreciable asset base caused by asset impairments and the change in the economic useful lives of certain Alberta coal-fired plants.

In 2011, depreciation expense increased $13 million compared to 2010, due to an increased asset base, the impact of the 2010 decrease in Wabamun decommissioning and restoration costs, and the writedown of capital spares, partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Asset Impairment Charges

Centralia Thermal

On July 25, 2012, we announced that a long-term power agreement was signed for the supply of power from December 2014 until the Centralia Thermal plant is fully retired in 2025. Refer to the Significant Events section of this MD&A for further discussion. As a result, we completed an assessment of whether the carrying amount of the facility was recoverable based on an estimate of fair value less costs to sell. The fair value was determined based on the future cash flows expected to be derived from the plant's operations, determined by prices evidenced in the agreement and in the marketplace. A pre-tax impairment charge of $347 million resulted and is included in the Generation Segment.

In addition to the impairment charge, $169 million of deferred income tax assets were written off as it is no longer probable that sufficient taxable income will be available from our U.S. operations to allow the benefit associated with the deferred income tax assets to be utilized.

The cumulative $516 million impact associated with the plant impairment and writeoff of deferred income tax assets has been adjusted in calculating earnings on a comparable basis. Please refer to the Non-IFRS Measures section of this MD&A.

Sundance Units 1 and 2

During 2012, we recognized a net pre-tax impairment charge of $2 million, comprised of a $43 million charge in the second quarter that resulted from the conclusion of the Sundance Units 1 and 2 arbitration and a $41 million reversal in the third quarter that arose as a result of the additional years of merchant operations expected to be realized at Sundance Units 1 and 2 due to the amendments to Canadian federal regulations discussed in the Significant Events section of this MD&A.

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

The losses and reversal are included in the Generation Segment.

Renewables

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

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

Gas

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

Finance Leases

Solomon

The 125 MW natural gas-fired and diesel-fired facility and associated Agreement are accounted for as a finance lease. The facility is currently under construction and is expected to be commissioned during the first half of 2013. Please refer to the Significant Events section of this MD&A.

Fort Saskatchewan

Fort Saskatchewan is a natural gas-fired facility with a gross generating capacity of 118 MW in operation, of which TA Cogen has a 60 per cent ownership interest (35 MW net ownership interest). Key operational information adjusted to reflect our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

Year ended Dec. 31	2012	2011	2010
Availability *(%)*	**92.0**	98.1	97.1
Production *(GWh)*	**470**	481	488

For the year ended Dec. 31, 2012, availability decreased compared to 2011, due to higher planned outages. Availability for the year ended Dec. 31, 2011 was comparable to 2010.

For the year ended Dec. 31, 2012, production decreased by 11 GWh compared to 2011, due to higher planned outages, partially offset by increased customer demand.

In 2011, production decreased by 7 GWh compared to 2010, primarily due to lower customer demand, partially offset by lower planned outages.

Total Finance Lease Income
Total finance lease income for the year ended Dec. 31, 2012 increased $8 million compared to 2011, due to the payments we began receiving in October 2012 under the Agreement with Fortescue.

Finance lease income for the year ended Dec. 31, 2011 was consistent with 2010 at $8 million.

Equity Investments

Our interests in the CE Gen and Wailuku joint ventures are accounted for using the equity method and are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 839 MW of gross generating capacity (390 MW net ownership interest). The table below summarizes key operational information adjusted to reflect our interest in these investments:

Year ended Dec. 31	**2012**	2011	2010
Availability *(%)*	**94.2**	94.9	95.5
Production *(GWh)*			
Gas	**380**	308	411
Renewables	**1,200**	1,312	1,299
Total production	**1,580**	1,620	1,710

Availability for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 due to higher unplanned outages.

In 2011, availability decreased compared to 2010 due to higher planned and unplanned outages at our CE Gen facilities.

For the year ended Dec. 31, 2012, production decreased compared to the same period in 2011 due to higher unplanned outages and lower customer demand.

In 2011, production decreased compared to 2010 due to unfavourable market conditions and higher planned and unplanned outages.

Equity losses from CE Gen and Wailuku for the year ended Dec. 31, 2012 were $15 million as compared to income of $14 million for 2011. The equity income decreased primarily due to higher unplanned outages and unfavourable pricing.

In 2011, equity income from CE Gen and Wailuku was $14 million as compared to income of $7 million for 2010. The equity income increased primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

Since 2001, a significant portion of the CE Gen plants have been operating under modified fixed energy price contracts. Commencing May 1, 2012, the terms of the contracts reverted to a pricing clause that permits the power purchaser to pay their short-run avoided costs ("SRAC") as the price for power. The SRAC is linked to the price of natural gas. There can be no assurances that prices based on the avoided cost of energy after May 1, 2012 will result in revenues equivalent to those realized under the fixed energy price structure.

Energy Trading:

Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving gross margins, while remaining within Value at Risk ("VaR") limits, is a key measure of Energy Trading's activities. Refer to the Value at Risk and Trading Positions discussion in the Risk Management section of this MD&A for further discussion on VaR.

Energy Trading utilizes contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. If the activities are performed on behalf of the Generation Segment, the results of these activities are included in the Generation Segment.

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

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

A portion of OM&A costs incurred within Energy Trading is allocated to the Generation Segment based on an estimate of operating expenses and a percentage of resources dedicated to providing support and services. This fixed fee intersegment allocation is represented as a cost recovery in Energy Trading and an operating expense within Generation.

The results of the Energy Trading Segment, with all trading results presented on a net basis, are as follows:

Year ended Dec. 31	2012	2011	2010
Revenues	3	137	41
Fuel and purchased power	-	-	-
Gross margin	3	137	41
Operations, maintenance, and administration	28	43	17
Depreciation and amortization	-	1	2
Intersegment cost allocation	(13)	(8)	(5)
Operating income (loss)	(12)	101	27

For the year ended Dec. 31, 2012, Energy Trading gross margins decreased compared to the same period in 2011 primarily due to the impact of unexpected weather patterns, plant outages, and unfavourable market expectations on power and gas pricing for trading positions held.

In 2011, Energy Trading gross margins increased compared to 2010 primarily due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from lower pricing.

OM&A expenses for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 primarily due to decreased compensation costs as a result of lower earnings.

In 2011, OM&A costs increased compared to 2010 as a result of higher compensation costs associated with favourable results and costs associated with several productivity initiatives.

For the year ended Dec. 31, 2012, the intersegment cost allocation increased compared to the same period in 2011 due to additional support costs charged to the Generation Segment resulting from an increase in work performed by Energy Trading.

Corporate: Our Generation and Energy Trading Segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.

The expenses incurred by the Corporate Segment are as follows:

Year ended Dec. 31	2012			2011	2010
	Total	Comparable adjustments	Comparable total	Total	Total
Operations, maintenance, and administration	81	-	81	83	69
Depreciation and amortization	20	-	20	21	19
Restructuring charges	8	(8)	-	-	-
Taxes, other than income taxes	1	-	1	-	-
Operating loss	110	(8)	102	104	88

OM&A for the year ended Dec. 31, 2012 was comparable to 2011. In 2011, OM&A costs increased compared to 2010 due to costs associated with several productivity initiatives and higher compensation costs.

Net Interest Expense

The components of net interest expense are shown below:

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

For the year ended Dec. 31, 2012, net interest expense increased compared to 2011 primarily due to lower capitalized interest.

In 2011, net interest expense increased compared to 2010 due to lower capitalized interest, lower interest income related to the resolution of certain outstanding tax matters in 2010, and higher interest rates, partially offset by favourable foreign exchange rates and lower debt levels.

Non-Controlling Interests

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural gas-fired and one coal-fired generating facility with a total gross generating capacity of 704 MW. Stanley Power owns the minority interest in TA Cogen. Natural Forces owns a 17 per cent interest in our Kent Hills facility, which operates 150 MW of wind assets. Since we own a controlling interest in TA Cogen and Kent Hills, we consolidate the entire earnings, assets, and liabilities in relation to our ownership of those assets.

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

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2012 of $37 million was comparable to $38 million in 2011.

In 2011, earnings attributable to non-controlling interests increased $14 million compared to 2010, due to higher earnings at TA Cogen.

Income Taxes

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

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

Year ended Dec. 31	2012	2011	2010
Earnings (loss) before income taxes	**(443)**	449	304
Income attributable to non-controlling interests	**(37)**	(38)	(24)
Equity (income) loss	**15**	(14)	(7)
Impacts associated with certain de-designated and ineffective hedges	**72**	(127)	(43)
Asset impairment charges	**324**	17	28
Restructuring charges	**13**	-	-
Gain on sale of assets	**(3)**	(16)	-
Sundance Units 1 and 2 arbitration	**254**	-	-
(Gain on sale of) reserve on collateral	**(15)**	18	-
Other non-comparable items	**3**	10	-
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**183**	299	258
Income tax expense	**103**	106	24
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**25**	(46)	(15)
Income tax (expense) recovery related to asset impairment charges	**(5)**	4	12
Income tax recovery related to restructuring charges	**3**	-	-
Income tax expense related to gain on sale of assets	**(1)**	(4)	-
Income tax recovery related to Sundance Units 1 and 2 arbitration	**65**	-	-
Income tax (expense) recovery related to (gain on sale of) reserve on collateral	**(4)**	5	-
Income tax expense related to writeoff of deferred income tax assets	**(169)**	-	-
Income tax expense related to changes in corporate income tax rates	**(8)**	-	-
Income tax recovery related to the resolution of certain outstanding tax matters	**9**	-	30
Reclassification of Part VI.1 tax	**-**	(2)	-
Income tax recovery related to other non-comparable items	**1**	3	-
Income tax expense excluding non-comparable items	**19**	66	51
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items *(%)*	**10**	22	20

For the year ended Dec. 31, 2012, income tax expense excluding non-comparable items decreased compared to 2011 due to lower comparable earnings, changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, and the positive resolution of certain outstanding tax matters.

In 2011, income tax expense excluding non-comparable items increased compared to 2010 due to higher comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

For the year ended Dec. 31, 2012, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items decreased compared to 2011 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, the effect of certain deductions that do not fluctuate with earnings, and the positive resolution of certain outstanding tax matters.

In 2011, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items increased compared to 2010 due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

Financial Position

The following chart outlines significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2011 to Dec. 31, 2012:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	(22)	Timing of receipts and payments
Accounts receivable	56	Timing of customer receipts
Collateral paid	(26)	Decreased collateral requirements associated with changes in forward prices
Investments	(21)	Equity loss and unfavourable foreign exchange
Long-term receivable	(18)	Sale of collateral on hand at MF Global Inc.
Finance lease receivable (current and long-term)	314	Acquisition of Solomon power station and related contract
Property, plant, and equipment, net	(227)	Asset impairments and depreciation partially offset by additions
Deferred income tax assets	(119)	Writeoff of deferred income tax assets related to profitability of U.S. operations
Risk management assets (current and long-term)	(220)	Price movements and changes in underlying positions
Accounts payable and accrued liabilities	32	Timing of payments and higher capital accruals
Collateral received	(14)	Reduction in collateral received from counterparties associated with changes in forward prices
Income taxes payable	(16)	Increase in instalment payments
Long-term debt (including current portion)	180	Increased borrowings under credit facilities and issuance of senior notes, partially offset by repayments
Decommissioning and other provisions (current and long-term)	(70)	Decrease in decommissioning and commercial provisions, including the Sundance Units 1 and 2 arbitration impacts
Deferred credits and other long-term liabilities	20	Increase in defined benefit accrual
Deferred income tax liabilities	(54)	Positive resolution of certain outstanding tax matters and the Sundance Units 1 and 2 arbitration impacts
Risk management liabilities (current and long-term)	(77)	Price movements and changes in underlying positions
Equity attributable to shareholders	(259)	Net loss for the year and share dividends, partially offset by issuance of common and preferred shares
Non-controlling interests	(28)	Distributions to non-controlling interests net of non-controlling interests' portion of net earnings

Financial Instruments

Financial instruments are used to manage our exposure to interest rates, commodity prices, currency fluctuations, as well as other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps, and options to achieve our risk management objectives, which are described below. Financial instruments are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, these changes in fair value will generally not affect earnings until the financial instrument is settled.

We have two types of financial instruments: (1) those that are used in the Energy Trading and Generation Segments in relation to energy trading activities, commodity hedging activities, and other contracting activities and (2) those used in the hedging of debt, projects, expenditures, and our net investment in foreign operations.

A portion of our financial instruments and physical commodity contracts are recorded under own use accounting or qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge, and is outlined in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion is recognized in net earnings.

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

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

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

Fair Value Hedges

Fair value hedges are used to offset the impact of changes in the fair value of fixed rate long-term debt caused by variations in market interest rates. We use interest rate swaps in our fair value hedges.

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

Event	Consolidated Statements of Earnings (Loss)	Consolidated Statements of Comprehensive Income (Loss)	Consolidated Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)	✓	–	✓	–
Settle contract	✓	–	✓	✓

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate, or commodity hedges and are used to offset foreign exchange, interest rate, and commodity price exposures resulting from market fluctuations.

Project Hedges

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies.

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

Event	Consolidated Statements of Earnings (Loss)	Consolidated Statements of Comprehensive Income (Loss)	Consolidated Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)[2]	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓

1 Some contracts may require an upfront cash investment.
2 Any ineffective portion is recorded in the Consolidated Statements of Earnings (Loss).

Foreign Exchange, Interest Rate, and Commodity Hedges

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps are used to offset the exposures resulting from foreign denominated long-term debt. Forward start interest rate swaps are used to offset the variability in cash flows resulting from anticipated issuances of long-term debt.

A summary of how typical foreign exchange, interest rate, and commodity hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings (Loss)	Consolidated Statements of Comprehensive Income (Loss)	Consolidated Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)[2]	–	✓	✓	–
Settle contract	✓	✓	✓	✓

When we do not elect hedge accounting, or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest, or exchange rates related to these financial instruments are recorded through the Consolidated Statements of Earnings (Loss) in the period in which they arise.

Net Investment Hedges

Foreign currency forward contracts and foreign denominated long-term debt are used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. We attempt to manage our foreign exchange exposure by matching foreign denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our U.S. dollar debt.

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

Event	Consolidated Statements of Earnings (Loss)	Consolidated Statements of Comprehensive Income (Loss)	Consolidated Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)[2]	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓
Reduction of net investment of foreign operation	✓	✓	✓	–

Non-Hedges

Financial instruments not designated as hedges are used to reduce commodity price, foreign exchange, and interest rate risks.

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

Event	Consolidated Statements of Earnings (Loss)	Consolidated Statements of Comprehensive Income (Loss)	Consolidated Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	✓	–
Reporting date (marked-to-market)	✓	–	✓	–
Roll-over into new contract	✓	–	✓	✓
Settle contract	✓	–	✓	✓
Divest contract	✓	–	✓	✓

1 Some contracts may require an upfront cash investment.

2 Any ineffective portion is recorded in the Consolidated Statements of Earnings (Loss).

Fair Values

The majority of fair values for our project, foreign exchange, interest rate, commodity hedges, and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonable possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2012, Level III instruments had a net asset carrying value of $31 million. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2011.

Employee Share Ownership

We employ a variety of stock-based compensation plans to align employee and corporate objectives.

Under the terms of our Stock Option Plans, employees below manager level may receive grants that vest in equal instalments over four years and expire after ten years.

Under the terms of the Performance Share Ownership Plan ("PSOP"), certain employees receive grants which, after three years, make them eligible to receive a set number of common shares, including the value of reinvested dividends over the period, or the equivalent value in cash plus dividends, based upon our total shareholder return relative to companies comprising the comparator group. After three years, once PSOP eligibility has been determined and provided our performance exceeded the 25th percentile, common shares are awarded, 50 per cent of the common shares are released to the participant and the remaining 50 per cent are held in trust for one additional year for employees below vice-president level, and for two additional years for employees at the vice-president level and above. The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below executive level for up to 30 per cent of the employee's base salary for the purchase of our common shares from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. As at Dec. 31, 2012, accounts receivable from employees under the plan totalled $4 million (2011 – $1 million). This program is not available to officers and senior management.

Employee Future Benefits

We have registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plan ceased for new Canadian employees on June 30, 1998. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010. The latest actuarial valuations for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2012 for the Canadian pension plan and Jan. 1, 2012 for the U.S. pension plan.

We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65 (other post-employment benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2010 for the Canadian plan and Jan. 1, 2012 for the U.S. plan.

The supplemental pension plan is an obligation of the Corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $64 million to secure the obligations under the supplemental plan.

Statements of Cash Flows

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2012 and 2011:

Year ended Dec. 31	**2012**	2011	**Explanation of change**
Cash and cash equivalents, beginning of year	**49**	35	
Provided by (used in):			
Operating activities	**520**	690	Lower cash earnings of $33 million and unfavourable changes in working capital of $137 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration
Investing activities	**(1,048)**	(608)	Acquisition of Solomon finance lease for $312 million, an increase in additions to PP&E and intangibles of $259 million and a decrease in proceeds on sale of PP&E and facilities of $46 million, partially offset by a net positive impact of $176 million related to changes in collateral received from or paid to counterparties
Financing activities	**504**	(70)	Issuance of long-term debt of $388 million, increase in issuance of common shares of $291 million, and a decrease in common share cash dividends of $87 million due to dividends reinvested through the dividend reinvestment plan, partially offset by an increase in debt repayments of $80 million, a decrease of $50 million in proceeds from the issuance of preferred shares, an increase in realized losses on financial instruments of $40 million, and an increase in preferred share dividends of $17 million
Translation of foreign currency cash	**2**	2	
Cash and cash equivalents, end of year	**27**	49	

Year ended Dec. 31	2011	2010	Explanation of change
Cash and cash equivalents, beginning of year	35	53	
Provided by (used in):			
Operating activities	690	852	Unfavourable changes in working capital balances of $166 million primarily due to the timing of payments and receipts offset by higher cash earnings of $4 million
Investing activities	(608)	(777)	Decrease in additions to PP&E of $355 million and proceeds on the sale of facilities and development projects of $40 million, offset by a $156 million decrease in collateral received from counterparties, an increase of $54 million in collateral paid to counterparties, a decrease of $15 million in proceeds on the sale of the minority interest in Kent Hills, and a decrease of $26 million due to the resolution of certain outstanding tax matters in 2010
Financing activities	(70)	(92)	Lower net debt repayments, decrease in cash dividends paid on common shares of $25 million, offset by a decrease in proceeds on issuance of preferred shares of $24 million and an increase in dividends paid on preferred shares of $15 million
Translation of foreign currency cash	2	(1)	
Cash and cash equivalents, end of year	49	35	

Liquidity and Capital Resources

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

Our liquidity needs are met through a variety of sources, including cash generated from operations, borrowings under our long-term credit facilities, and long-term debt or equity issued under our Canadian and U.S. shelf registrations. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling limited partners, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.2 billion as at Dec. 31, 2012 compared to $4.0 billion as at Dec. 31, 2011. Total long-term debt increased from Dec. 31, 2011 primarily due to higher borrowing under our credit facility and the issuance of additional fixed rate long-term debt, partially offset by the repayment of debt maturing in the year.

Credit Facilities

At Dec. 31, 2012, we had a total of $2.0 billion (2011 – $2.0 billion) of committed credit facilities, of which $0.8 billion (2011 – $0.9 billion) is not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2012, the $1.3 billion (2011 – $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $1.0 billion (2011 – $0.8 billion) and letters of credit of $0.3 billion (2011 – $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2016, with the remainder comprised of bilateral credit facilities, of which $0.3 billion matures in the third quarter of 2013 and $0.2 billion matures in the fourth quarter of 2014. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.8 billion available under the credit facilities, we also have $25 million of available cash.

Share Capital

At Dec. 31, 2012, we had 254.7 million (2011 – 223.6 million) common shares issued and outstanding. During the year ended Dec. 31, 2012, 31.1 million (2011 – 3.3 million) common shares were issued for $456 million (2011 – $69 million), which was comprised of 21.2 million (Dec. 31, 2011 – nil) common shares issued through a public offering for total net proceeds of $295 million (Dec. 31, 2011 – nil), 9.7 million (Dec. 31, 2011 – 3.2 million) common shares for $159 million (Dec. 31, 2011 – $67 million) for dividends reinvested under the terms of the Plan and 0.2 million (Dec. 31, 2011 – 0.1 million) common shares issued for proceeds of $2 million (Dec. 31, 2011 – $2 million).

At Dec. 31, 2012, we had 32.0 million (2011 – 23.0 million) preferred shares issued and outstanding. During the year ended Dec. 31, 2012, 9.0 million (2011 – 11.0 million Series C) Series E Preferred Shares were issued for $219 million, net of after-tax issuance costs of $6 million (2011 – $269 million, net of after-tax issuance costs of $6 million).

On Feb. 26, 2013, we had 258.4 million common shares and 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E first preferred shares outstanding.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At Dec. 31, 2012, we provided letters of credit totalling $336 million (2011 – $328 million) and cash collateral of $19 million (2011 – $45 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Working Capital

As at Dec. 31, 2012, the excess of current liabilities over current assets is $447 million (2011 – $67 million). The excess of current liabilities over current assets increased $380 million compared to 2011 due to an increase in the current portion of long-term debt and a decrease in risk management assets, partially offset by a decrease in the current portion of decommissioning and other provisions, an increase in accounts receivable, and a decrease in risk management liabilities.

Capital Structure

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

	2012		2011	
As at Dec. 31	**Amount**	**%**	Amount	%
Debt, net of available cash and cash equivalents	**4,192**	**56**	4,005	52
Non-controlling interests	**330**	**4**	358	5
Equity attributable to shareholders	**3,010**	**40**	3,269	43
Total capital	**7,532**	**100**	7,632	100

Commitments

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

	Fixed price gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Operating leases	Coal supply and mining agreements	Long-term service agreements	Long-term debt[1]	Interest on long-term debt[2]	Growth, major, and development project commitments[3]	Total
2013	76	40	10	125	18	607	212	131	1,219
2014	35	10	8	102	17	209	185	–	566
2015	11	11	8	96	9	654	153	–	942
2016	10	8	7	98	3	680	138	–	944
2017	9	3	7	25	–	2	127	–	173
2018 and thereafter	106	5	28	530	–	2,055	802	–	3,526
Total	**247**	**77**	**68**	**976**	**47**	**4,207**	**1,617**	**131**	**7,370**

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

Unconsolidated Structured Entities or Arrangements

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

Climate Change and the Environment

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

1 Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature between the third quarter of 2013 and the fourth quarter of 2014.

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

3 Includes $54 million commitment remaining on agreement with Alstom Power & Transport Canada Inc. for the manufacture, delivery, and construction of the Sundance Units 1 and 2 waterwalls. The total fixed price commitment under the contract was $79 million.

Ongoing and Recently Passed Environmental Legislation

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

Alberta

In October 2012, the Alberta Government released its renewed Clean Air Strategy, which sets out a broad framework for managing air emissions and air quality in the future. The framework focuses on a continuous improvement model for regional air quality. It also states that Alberta will take responsibility for implementing any federal air quality standards. There are no specific requirements in this framework that immediately impact our operations.

In Alberta there are requirements for coal-fired generation units to implement additional air emission controls for oxides of nitrogen ("NOx"), sulphur dioxide ("SO_2"), and particulate matter, once they reach the end of their respective PPAs, 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, the release of the federal GHG regulations may create a potential misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with the provincial government to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply.

Canada

On Sept. 11, 2012, the Canadian federal government published the final regulations governing GHG emissions from coal-fired power plants, to become effective on July 1, 2015. The regulations provide for up to 50 years of life for coal units, at which point units must meet an emissions performance standard of approximately 420 tonnes per GWh. There are some exceptions that require older units commissioned before 1975 to reach end of life by Dec. 31, 2019, and units commissioned between 1975 and 1986 to reach end of life by Dec. 31, 2029. Compared to the initial draft version of these regulations, we believe the final regulations provide additional operating time and increased flexibility for our Canadian coal units, allowing for a smoother transition of those units in a more cost-effective manner.

United States

On March 27, 2012, the U.S. Environmental Protection Agency ("EPA") proposed GHG emission standards for future coal-fired power plants. Compliance under the proposed standard will likely be met with fuel switching or clean coal technologies. As this regulatory framework is for new coal-fired plants, we expect no material impact on our existing coal units at Centralia.

In December 2011, the EPA issued national standards for mercury emissions from power plants. Existing sources will have up to four years to comply. We have already voluntarily installed mercury capture technology at our Centralia coal-fired plant, and began full capture operations in early 2012. We have also installed additional technology to further reduce NOx, consistent with the Washington State Bill passed in April 2011 requiring TransAlta to begin operating such technology by Jan. 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 certified by the Federal Energy Regulatory Commission in the U.S. 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.

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

TransAlta Activities

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

In 2012, we estimate that 27 million tonnes of GHGs with an intensity of 0.816 tonnes per MWh (2011 – 29 million tonnes of GHGs with an intensity of 0.859 tonnes per MWh) were emitted as a result of normal operating activities[1].

Our environmental management programs encompass the following elements:

Renewable Power
We continue to invest in and build renewable power resources. Our 68 MW New Richmond wind facility is currently under construction and slated for completion during the first quarter of 2013. 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, and voluntarily at our Centralia coal-fired plant in 2012. Our new Keephills Unit 3 plant began operations 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 Genesee Unit 3. Uprate projects recently completed at our Keephills and Sundance plants are expected to improve the energy and 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 discussions have allowed us to engage in proactive discussions with governments and industry participants to meet environmental requirements over the longer term.

Clean Combustion Technologies
We look to advance clean energy technologies through organizations such as the Canadian Clean 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 promote carbon capture and storage systems and infrastructure for Canada.

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

1 2012 data are estimates based on best available data at the time of report production. GHGs include water vapour, carbon dioxide ("CO_2"), methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future 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 MD&A contains forward-looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and major projects, and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the impact of certain hedges on future reported earnings and cash flows; expectations related to future earnings and cash flow from operating and contracting activities; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term, and the resulting impact on electricity prices; expected impacts of load growth and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; 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 estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment; our credit practices; and the estimated contribution of Energy Trading activities to gross margin.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and the availability of fuel supplies required to generate electricity; our ability to contract our generation for prices that will provide expected returns; 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; the 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; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal and contractual proceedings involving the Corporation; reliance on key personnel; labour relations matters; and development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of this MD&A and under the heading "Risk Factors" in our 2013 Annual Information Form.

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

2013 Outlook

Business Environment

Demand

Alberta electricity demand is expected to grow at an average rate of approximately two to three per cent annually as a result of several large oil sands projects that will bring new demand over the next several years. Electricity demand in the Pacific Northwest is expected to increase approximately one per cent per year, due in part to a large emphasis on energy efficiency across the region. Demand in Ontario is expected to return to a moderate growth rate of about one per cent annually.

Supply

New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy and natural gas-fired generation across most North American markets. This expectation is driven by the relatively low prices in the natural gas market combined with a continued expectation that GHG legislation of some form is still expected in Canada and the U.S.

Alberta will likely see a relatively flat reserve margin over the next several years as Sundance Unit 1 and 2 are brought back online and natural gas capacity is added in the 2015 time frame to meet the expected load growth. The Ontario reserve margin will also remain relatively flat if coal capacity is retired as expected during 2013. The Pacific Northwest is expected to see slightly falling reserve margins in the near term, although the market is expected to remain well supplied.

Green technologies have gained favour with regulators and the general public, creating increasing pressure to supply power using renewable resources such as wind, hydro, geothermal, and solar. In Alberta, 45 MW of biomass generation facilities are currently under construction and approximately 1,000 MW of wind generation facilities have received regulatory approval. A further 2,400 MW of wind generation facilities have applied for interconnection and/or regulatory approval. Not all announced generation is expected to be built and some projects cannot be developed prior to transmission expansions.

Cogeneration projects at large oil sands developments are expected to be a key source of new generation supply within Alberta. These projects supply heat to the oil sands facility alongside electricity production. As a result, these facilities are a very competitive and efficient source of new generation capacity. Alberta currently has about 4,000 MW of cogeneration capacity and another 400 MW of capacity is under construction.

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

Transmission

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

The existing Alberta transmission system is congested and aging, resulting in excessive energy loss and constraints on our generation operations as expected electricity flows exceed the system's current limits. The reinforcement of the transmission system as provided by the construction of the new transmission lines announced in 2012 will alleviate these constraints, reduce transmission line losses, and allow for the development of additional generation.

Power Prices

In 2013, power prices in Alberta are expected to be lower than in 2012 due to fewer planned turnarounds and increased capacity due to additional generation facilities coming online, partially offset by load growth. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, overall prices will still remain weak because of low natural gas prices and slow load growth.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. We are in discussions with the provincial government to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply. This may provide additional flexibility to coal-fired generators in meeting the regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of this MD&A.

In addition, there are ongoing discussions between the federal and provincial governments regarding a national Air Quality Management System for air pollutants. In Alberta's recently released Clean Air Strategy, the province indicated that its provincial air quality management system will operationalize any national system. Our current outlook is that, for Alberta, provincial regulations will be considered as equivalent to any future national framework.

In the U.S., it is not yet clear how climate change legislation for existing fossil-fuel-based generation will unfold. Additionally, new air pollutant regulations for the power sector are anticipated, but will not directly affect our coal-fired operations in Washington State. TransAlta's agreement with Washington State, established in April 2011, provides regulatory clarity at the state level regarding an emissions regime related to the Centralia Coal plant until 2025.

Beginning in 2013, direct deliveries of power to the California Independent System Operator will be subject to a compliance obligation established by the California Air Resources Board's ("CARB") cap and trade program. As CARB continues to finalize their regulations, we will stay at the forefront of regulatory changes to ensure we remain in compliance with the cap and trade program.

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

The siting, construction, and operation of electrical energy facilities requires interaction with many stakeholders. Recently, certain stakeholders have brought actions against government agencies and owners over alleged adverse impacts of wind projects. We are monitoring these claims in order to assess the risk associated with these activities.

Economic Environment

The economic environment showed signs of weakness during 2012 and in 2013 we expect slow to moderate growth in Alberta and Australia, and low growth in other markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no material counterparty losses in 2012, and we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase in 2013 due to Sundance Units 1 and 2 returning to service and the completion of the New Richmond facility. Prior to the effect of any economic dispatching, overall production is expected to increase in 2013 due to lower planned outages. Overall availability is expected to be in the range of 89 to 90 per cent in 2013 due to lower planned outages across the fleet.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 77 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming year. As at the end of 2012, approximately 85 per cent of our 2013 capacity was contracted. The average price of our short-term physical and financial contracts for 2013 ranges from $60 to $65 per MWh in Alberta, and from U.S.$40 to $45 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. In January 2013, we gave notice to Prairie Mines and Royalty Ltd. that we will assume, through our wholly owned SunHills Mining Limited Partnership, operating and management control of the Highvale Mine. We are currently assessing the accounting impact of this change. Coal costs for 2013, on a standard cost basis, are expected to be comparable to 2012 with the assumption of operational and management control offsetting any cost increases mentioned above.

Although we own the Centralia mine in the State of Washington, it is not currently operational. Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2013 is expected to decrease by a range of nine to eleven per cent.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges will be recognized in net earnings. For more information on the inventory impairment charges and reversals recorded in 2012, please refer to the Significant Events section of this MD&A.

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

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

Operations, Maintenance, and Administration Costs
OM&A costs for 2013 are expected to be relatively consistent with 2012 OM&A, primarily due to cost savings as a result of our restructuring in the fourth quarter offset by additional costs as Sundance Units 1 and 2 are returned to service and the commencement of operations at our New Richmond facility.

Energy Trading
Earnings from our Energy Trading Segment are affected by prices in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure in order to maximize earnings while still maintaining an acceptable risk profile. Our target is for Energy Trading to contribute between $40 million and $60 million in gross margin for 2013.

Exposure to Fluctuations in Foreign Currencies
Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar, Euro, and Australian dollar, by offsetting foreign denominated assets with foreign denominated liabilities and by entering into foreign exchange contracts. We also have foreign denominated expenses, including interest charges, which largely offset our net foreign denominated revenues.

Net Interest Expense
Net interest expense for 2013 is not expected to change materially compared to 2012. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar can affect the amount of net interest expense incurred.

Liquidity and Capital Resources
If there is increased volatility in power and natural gas markets, or if market trading activities increase, we may need additional liquidity in the future. We expect to maintain adequate available liquidity under our committed credit facilities.

Accounting Estimates
A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of this MD&A, are based on the current economic environment and outlook. As a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities and asset valuation for our asset impairment calculations.

Income Taxes
The effective tax rate on earnings excluding non-comparable items for 2013 is expected to be approximately 22 to 27 per cent, which is comparable to the statutory tax rate of 25 per cent.

Capital Expenditures

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

Growth and Major Project Expenditures
In 2012, we spent a total of $246 million on growth and major project expenditures, net of any joint venture contributions received. We successfully completed uprates at Keephills Units 1 and 2 and Sundance Unit 3. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator. Of the $246 million, $203 million is associated with two significant growth and major projects that will be completed in 2013.

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

	Total Project		2012[1]	2013		
	Estimated spend	Spend to date[2]	Actual spend	Estimated spend	Target completion date	Details
Growth						
New Richmond[3]	212	188	159	15-25	Q1 2013	A 68 MW wind farm in Quebec
Major Projects						
Sundance Units 1 and 2	190	44	44	130-145	Q4 2013	Sundance Units 1 and 2 comprising 560 MW of our Sundance power plant
Total major projects and growth	**402**	**232**	**203**	**145-170**		

Our total estimated spend for New Richmond increased by $7 million primarily due to unfavourable foreign exchange rates and increased costs incurred due to construction delays.

During 2012, we entered into an agreement with Alstom Power & Transport Canada Inc. for the manufacture, delivery, and construction of the Sundance Units 1 and 2 waterwalls. The total fixed price commitment under the contract is $79 million, with $25 million incurred in 2012 and $54 million expected to be incurred in 2013. Payments will be made as agreed milestones are achieved. Additional costs to be paid under the contract include reimbursable items, such as direct labour, subcontractors, and labour incentive allowances.

Transmission

For the year ended Dec. 31, 2012, a total of $4 million was spent on transmission projects. The estimated spend for 2013 on transmission projects is $7 million. Transmission projects consist of the major maintenance and reconfiguration of Alberta's transmission networks to increase capacity of power flow in the lines.

Sustaining Capital and Productivity Expenditures

A significant portion of our sustaining capital and productivity expenditures is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event.

For 2013, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Spend in 2012	Expected spend in 2013
Routine capital	Expenditures to maintain our existing generating capacity	115	90-100
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	38	40-50
Planned major maintenance	Regularly scheduled major maintenance	286	165-185
Total sustaining expenditures		**439**	**295-335**
Productivity capital	Projects to improve power production efficiency	57	30-50
Total sustaining and productivity expenditures		**496**	**325-385**

As a result of assuming the operating and management control of the Highvale Mine, sustaining capital and productivity expenditures for 2013 may be adjusted throughout the year as additional costs are incurred. We are currently assessing the impact that this will have on our 2013 sustaining capital and productivity expenditures.

1 *In 2012, we also spent a combined $40 million on facilities that had previously commenced operations. During the second quarter of 2012, we transferred $1 million from growth and major projects to sustaining capital and productivity expenditures for capital spares.*

2 *Represents amounts spent as of Dec. 31, 2012.*

3 *New Richmond total project costs spent to date include expenditures of $5 million that were included in project development costs in 2011.*

Our planned major maintenance program relates to regularly scheduled major maintenance activities and includes costs related to inspection, repair, and maintenance, and replacement of existing components. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred. Details of the 2013 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2013
Capitalized	90-105	75-80	165-185
Expensed	–	0-5	0-5
	90-105	75-85	165-190

	Coal	Gas and Renewables	Total
GWh lost	1,660-1,670	420-430	2,080-2,100

Financing

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

Risk Management

Our business activities expose us to a variety of risks including, but not limited to, increased regulatory changes, rapidly changing market dynamics, and increased volatility in our key commodity markets. Our goal is to manage these risks so that we are reasonably protected from an unacceptable level of earnings or financial exposure while still enabling business development. We use a multi-level risk management oversight structure to manage the risks arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface.

The responsibilities of various stakeholders of our risk management oversight structure are described below:

The Board of Directors provides stewardship of the Corporation; ensures that the Corporation establishes policies and procedures for the identification, assessment and management of principal risks and risk appetite; and receives an annual comprehensive Enterprise Risk Management ("ERM") review. The ERM review consists of a holistic view of the Corporation's inherent risks, how we mitigate these risks, and residual risks. It defines our risks, discusses who is responsible to manage each risk, how the risks are interrelated with each other, and identifies the applicable risk metrics.

The Audit and Risk Committee ("ARC"), established by the Board of Directors, provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of our financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration; independence; performance and reports; and the legal and risk compliance programs as established by management and the Board of Directors. The ARC approves our Commodity and Financial Exposure Management policies and reviews quarterly ERM reporting.

The Risk Management Committee ("RMC") is chaired by our Chief Financial Officer and is comprised of the Executive Vice-President Corporate Development, Vice-President and Treasurer, Managing Director Trading, Executive Vice-President Operations, Vice-President Risk, Vice-President Compliance, and Chief Engineer. The RMC acts as the operational and financial risk oversight body for the Corporation.

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

Risk Controls

Our risk controls have several key components:

Enterprise Tone

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

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a corporate code of conduct on an annual basis.

Reporting

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

Whistleblower System

We have a system in place where employees, shareholders, or other stakeholders may anonymously report any potential ethical concerns. These concerns can be submitted anonymously, either directly to the ARC or to the Director, Internal Audit, who engages Corporate Security, Legal, and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the chair of the ARC.

Value at Risk and Trading Positions

VaR is one of the primary measures used to manage our exposure to market risk resulting from energy trading activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in energy trading positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2012 associated with our proprietary energy trading activities was $2 million (2011 – $5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future results and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

Certain sections will show the after-tax effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes in 2012. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes.

Volume Risk

Volume risk relates to the variances from our expected production. For example, the financial performance of our hydro, wind, and geothermal operations are partially dependent upon the availability of their input resources in a given year. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- actively managing our assets and their condition through the Generation and Capital and Asset Reporting groups in order to be proactive in plant maintenance so that they are available to produce when required,
- monitoring water resources throughout Alberta and British Columbia to the best of our ability and optimizing this resource against real-time electricity market opportunities,
- placing our wind and geothermal facilities in locations that we believe to have sufficient resources in order for us to be able to generate sufficient electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require, and
- diversifying our fuels and geography as one way of mitigating regional or fuel-specific events.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	22

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal, and corrosion damage in boilers, generators, and turbines, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we may be required to compensate the purchaser for the loss in the availability of production or record reduced energy or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity.

The original equipment manufacturer for the generators at Sundance Units 3 to 6 has recently revised the operating criteria for the units such that they will no longer be able to produce the same amount of leading reactive power ("MVAR") at current active power output levels. Reactive power refers to the voltage support that is required to make electrical systems like the Alberta Interconnected Electrical System work and deliver active power through transmission lines. The production of reactive power can have a negative impact on the ability of a generator to produce active power as high reactive power demands can require a unit to reduce its active power output levels. TransAlta is engaged in the AESO's ongoing consultation process for the development of interconnection rules specifying, among other things, required MVAR levels.

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the availability of our generating facilities for the longest period of time,
- performing preventative maintenance on a regular basis,
- adhering to a comprehensive plant maintenance program and regular turnaround schedules,
- adjusting maintenance plans by facility to reflect the equipment type and age,
- having sufficient business interruption coverage in place in the event of an extended outage,
- having force majeure clauses in our thermal and other PPAs and other long-term contracts,
- using technology in our generating facilities that is selected and maintained with the goal of maximizing the return on those assets,
- monitoring technological advances and evaluating their impact upon our existing generating fleet and related maintenance programs,
- negotiating strategic supply agreements with selected vendors to ensure key components are available in the event of a significant outage,
- entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts, and
- developing a long-term asset management strategy with the objective of maximizing the life cycles of our existing facilities and/or replacement of selected generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short-, medium-, and long-term contracts to mitigate our exposure to short-term fluctuations in commodity prices,
- purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit, and
- ensuring limits and controls are in place for our proprietary trading activities.

In 2012, we had approximately 90 per cent (2011 – 93 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the costs of fuels used in production by:

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

In 2012, 69 per cent (2011 – 69 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2011 – 100 per cent) of our purchased coal costs were contractually fixed.

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

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$1.00/MWh	6
Natural gas price	$0.10/GJ	2
Coal price	$1.00/tonne	13

Fuel Supply Risk

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

At our coal-fired plants, input costs, such as diesel, tires, the price and availability of mining equipment, the volume of overburden removed to access coal reserves, rail rates, and the location of mining operations relative to the power plants are some of the exposures in our mining operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At Centralia Thermal, interruptions at our suppliers' mines and the availability of trains to deliver coal could affect our ability to generate electricity.

We manage coal supply risk by:

- ensuring that the majority of the coal used in electrical generation is from reserves permitted through coal rights we have purchased, thereby limiting our exposure to fluctuations in the supply of coal from third parties. As at Dec. 31, 2012, approximately 71 per cent (2011 – 79 per cent) of the coal used in generating activities is from reserves permitted through coal rights we have purchased,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at Centralia Thermal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- contracting sufficient trains to deliver the coal requirements at Centralia Thermal,
- ensuring coal inventories on hand at Alberta Thermal and Centralia Thermal are at appropriate levels for usage requirements,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,
- monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants, and
- hedging diesel exposure in mining and transportation costs.

We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

Environmental Risk

Environmental risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the U.S. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by imposing additional costs on the generation of electricity, such as emission caps, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental risk by:

- seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,
- having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety management system in place that is designed to continuously improve environmental performance,
- committing significant experienced resources to work with regulators in Canada and the U.S. to advocate that regulatory changes are well designed and cost effective,
- developing compliance plans that address how to meet or exceed emission standards for GHGs, mercury, SO_2, and oxides of nitrogen, which will be adjusted as regulations are finalized,
- purchasing emission reduction offsets,
- investing in renewable energy projects, such as wind and hydro generation, and
- investing in clean coal technology development, which potentially provides long-term promise for large emission reductions from fossil-fuel-fired generation.

We strive to be in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to the Governance and Environmental Committee.

In 2012, we spent approximately $63 million (2011 – $47 million) on environmental management activities, systems, and processes.

We are a founder of the Canadian Clean Power Coalition and the Integrated CO_2 Network industry consortia dedicated to developing clean combustion technologies, which in turn will mitigate the environmental and financial risks associated with continued fossil fuel use for power generation.

Credit Risk

Credit risk is the risk to our business associated with changes in the creditworthiness of entities with which we have commercial exposures. This risk results from the ability of a counterparty to either fulfill its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits, and the credit concentration with any specific counterparty,
- requiring formal sign-off on contracts that include commercial, financial, legal, and operational reviews,
- requiring security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfill its obligation or goes over its limits, and
- reporting our exposure using a variety of methods that allow key decision makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2011. We had no material counterparty losses in 2012, and we are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

A summary of our credit exposure for our energy trading operations and hedging activities at Dec. 31, 2012 is provided below:

Counterparty credit rating	Net exposure amount
Investment grade	154
Non-investment grade	–
No external rating, internally rated as investment grade	77
No external rating, internally rated as non-investment grade	19

The maximum credit exposure to any one customer for commodity trading operations, excluding the California Independent System Operator and California Power Exchange, and including the fair value of open trading positions, is $25 million (2011 – $38 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign denominated commodities from foreign suppliers, and our U.S. denominated debt. Our exposures are primarily to the U.S., Euro, and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

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

- hedging our net investments in foreign operations using a combination of foreign denominated debt and financial instruments. Our strategy is to offset 90 to 100 per cent of all such foreign currency exposures. At Dec. 31, 2012, we have hedged approximately 94 per cent (2011 – 92 per cent) of our foreign currency net investment exposure,
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure, and
- entering into forward foreign exchange contracts to hedge future foreign denominated receipts and expenditures, and all U.S. denominated debt outside of our net investment portfolio.

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

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.05	3

Liquidity Risk

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

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

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,
- reporting liquidity risk exposure for energy trading activities on a regular basis to the RMC, senior management, and the ARC,
- maintaining investment grade credit ratings, and
- maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our Alberta PPA plants. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

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

- employing a combination of fixed and floating rate debt instruments, and
- monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2012, approximately 24 per cent (2011 – 23 per cent) of our total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	1	8

Project Management Risk

As we are currently working on two generating projects, we face risks associated with cost overruns, delays, and performance.

We manage project risks by:

- ensuring all projects are vetted by the TRACT Committee so that projects have been highly scrutinized to see that established processes and policies are followed, risks have been properly identified and quantified, input assumptions are reasonable, and returns are realistically forecasted prior to senior management and Board of Directors approvals,
- using a consistent and disciplined project management methodology and processes,
- performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction,
- partnering with those who have previously been able to deliver projects economically and on budget,
- developing and following through with comprehensive plans that include critical paths identified, key delivery points, and backup plans,
- managing project closeouts so that any learnings from the project are incorporated into the next significant project,
- fixing the price and availability of the equipment, foreign currency rates, warranties, and source agreements as much as economically feasible prior to proceeding with the project, and
- entering into labour agreements to provide security around cost and productivity.

Human Resource Risk

Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

- potential disruption as a result of labour action at our generating facilities,
- reduced productivity due to turnover in positions,
- inability to complete critical work due to vacant positions,
- failure to maintain fair compensation with respect to market rate changes, and
- reduced competencies due to insufficient training, failure to transfer knowledge from existing employees, or insufficient expertise within current employees.

We manage this risk by:

- monitoring industry compensation and aligning salaries with those benchmarks,
- using incentive pay to align employee goals with corporate goals,
- monitoring and managing target levels of employee turnover, and
- ensuring new employees have the appropriate training and qualifications to perform their jobs.

In 2012, 43 per cent (2011 – 44 per cent) of our labour force was covered by 11 (2011 – 11) collective bargaining agreements. In 2012, two (2011 – three) agreements were renegotiated. We anticipate negotiating seven agreements in 2013. We do not anticipate any significant issues in the renewal of these agreements.

Regulatory and Political Risk

Regulatory and political risk describes the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market re-regulation, increased oversight and control, structural or design changes in markets or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business.

We manage these risks systematically through our Regulatory and Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electric system operators, and other stakeholders to resolve issues. We are active in monitoring market rules and developments, and in engaging in advocacy and policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer term.

International investments are subject to unique risks and uncertainties relating to the political, social, and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk

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

Reputation Risk

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

We manage reputation risk by:

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

Corporate Structure Risk

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

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit risk, and counterparty risk.

Income Taxes

Our operations are complex, and located in several countries. The computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by IFRS, based on all information currently available.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	5

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2012 was ten per cent. The effective income tax rate can change depending on the mix of earnings from various countries and certain deductions that do not fluctuate with earnings.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings that arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claims may not have a material adverse effect on us.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 2012. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our significant accounting policies are described in Note 2 to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, and other provisions. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our ARC and our independent auditors. The ARC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

These critical accounting estimates are described as follows:

Revenue Recognition

The majority of our revenues are derived from the sale of physical power, leasing of power facilities, and from energy trading activities.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each of these components is recognized upon output, delivery, or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each MWh produced and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above.

Energy trading activities use derivatives such as physical and financial swaps, forward sales contracts, and futures contracts and options, to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting and are presented on a net basis in the Consolidated Statements of Earnings (Loss) when hedge accounting is not applied. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the financial position date represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities.

The determination of the fair value of energy trading contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility, and liquidity, among other factors. Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or models.

Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy we use are defined below:

Level I

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

Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis and location differentials. We include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, we use observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, we rely on similar interest or currency rate inputs and other third-party information such as credit spreads.

Level III

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

We may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally developed fundamental price forecast is used in the valuation.

We also have various contracts with terms that extend beyond a liquid trading period. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

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

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2012, PP&E makes up 75 per cent of our assets, of which 99 per cent relates to the Generation Segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E, or the cash generating unit ("CGU") to which it belongs, is in excess of its recoverable amount.

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

Our businesses, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the PP&E or CGU to which it belongs. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. In estimating either fair value less costs to sell or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

As a result of our review in 2012 and other specific events, pre-tax asset impairment charges of $367 million (2011 – $17 million) were recorded related to certain facilities. Refer to the Asset Impairment Charges section of this MD&A for further details.

The impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to us, at which time the costs incurred subsequently are included in PP&E or Investments. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to net earnings.

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2012, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $564 million (2011 – $532 million), of which $41 million (2011 – $40 million) relates to mining equipment and is included in fuel and purchased power.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU, including goodwill, exceeds the unit's fair value, any excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill arose on the acquisitions of Canadian Hydro, Merchant Energy Group of the Americas, Inc., and Vision Quest Windelectric Inc. As at Dec. 31, 2012, this goodwill had a total carrying amount of $447 million (2011 – $447 million). Under the equity method of accounting, the goodwill arising on the acquisition of CE Gen is included in the determination of the amount of the investment in CE Gen and is tested for impairment as part of the net investment.

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

Determining the fair value of the CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins, and fuel and operating costs. Had assumptions been made that resulted in fair values of the CGUs declining by ten per cent from current levels, there would not have been any impairment of goodwill.

Leases

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

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Deferred income tax assets of $50 million (2011 – $169 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2012. These assets primarily relate to net operating and capital loss carryforwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $430 million (2011 – $484 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2012. These liabilities are comprised primarily of taxes on unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Employee Future Benefits

We provide selected pension and post-employment benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liability for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. For the year ended Dec. 31, 2012, the plan assets had a positive return of $23 million, compared to $11 million in 2011. The 2012 actuarial valuation used a six per cent rate of return on plan assets.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for PP&E in the period in which they are incurred if there is a legal or constructive obligation to reclaim the plant and/or site and if a reasonable estimate of a fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2012, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $262 million (2011 – $301 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.0 billion, which will be incurred between 2013 and 2072. The majority of these costs will be incurred between 2020 and 2050. The average discount used to calculate the carrying value of the decommissioning and restoration provisions was seven per cent.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	2
Undiscounted decommissioning and restoration provision	6	1

Other Provisions

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

Future Accounting Changes

Consolidated Financial Statements

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

Joint Arrangements

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

Disclosure of Interests in Other Entities

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

Investments in Associates and Joint Ventures and Separate Financial Statements

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

Amendments to IFRS 10, IFRS 11, and IFRS 12

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

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

Fair Value Measurement

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

Presentation of Financial Statements

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

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits* to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service and net interest costs are presented in net earnings and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI. The net interest cost introduced in these amendments removes the concept of expected return on plan assets that was previously recognized in net earnings. The amendments eliminate the option to defer the recognition of actuarial gains and losses, known as the 'corridor method'. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for TransAlta on Jan. 1, 2013 and must be applied retrospectively by TransAlta from Jan. 1, 2010. On adoption, we expect to reclassify an approximate $12 million after-tax charge from AOCI to Retained Earnings (Deficit), which represents the increase in prior periods' pension expense as a result of the application of the net interest cost requirements. No impacts are expected from the elimination of the corridor method as we have, since adoption of IFRS, recognized actuarial gains and losses in the period in which they occurred in OCI.

Financial Instruments

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

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

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

We do not expect that any material impacts will result from these standards, however, we continue to assess the impact of adopting these amendments on the consolidated financial statements.

Stripping Costs in the Production Phase of a Surface Mine

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

Offsetting Financial Assets and Liabilities

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

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

Annual Improvements 2009-2011

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

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

In October 2012, the IASB issued *Investment Entities (Amendments to IFRS 10 and 11 and IAS 27)*. The amendments provide an exception to the consolidation requirements in IFRS 12 and require investment entities to measure particular subsidiaries at fair value through profit or loss, rather than consolidate them. An investment entity is an entity whose business purpose is to invest funds solely for returns from capital appreciation, investment income, or both. The amendments are effective from Jan. 1, 2014, with early adoption permitted, and are not expected to have a material financial impact upon the consolidated financial position or results of operations.

Additional IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled "gross margin" and "operating income (loss)" in our Consolidated Statements of Earnings (Loss) for the year ended Dec. 31, 2012, 2011, and 2010. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Each business unit assumes responsibility for its operating results measured to gross margin and operating income. Operating income and gross margin provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Reconciliation to Net Earnings Attributable to Common Shareholders

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

Year ended Dec. 31	2012	2011	2010
Revenues	**2,262**	2,663	2,673
Fuel and purchased power	**809**	947	1,185
Gross margin	**1,453**	1,716	1,488
Operations, maintenance, and administration	**493**	545	510
Depreciation and amortization	**509**	482	464
Asset impairment charges	**324**	17	28
Inventory writedown	**44**	–	–
Restructuring charges	**13**	–	–
Taxes, other than income taxes	**28**	27	27
Operating income	**42**	645	459
Finance lease income	**16**	8	8
Equity income (loss)	**(15)**	14	7
Sundance Units 1 and 2 arbitration	**(254)**	–	–
Gain on sale of assets	**3**	16	–
Other income	**1**	2	–
Foreign exchange gain (loss)	**(9)**	(3)	8
Gain on sale of (reserve on) collateral	**15**	(18)	–
Net interest expense	**(242)**	(215)	(178)
Earnings (loss) before income taxes	**(443)**	449	304
Income tax expense	**103**	106	24
Net earnings (loss)	**(546)**	343	280
Non-controlling interests	**37**	38	24
Net earnings (loss) attributable to TransAlta shareholders	**(583)**	305	256
Preferred share dividends	**31**	15	1
Net earnings (loss) attributable to common shareholders	**(614)**	290	255

Earnings on a Comparable Basis

Presenting earnings on a comparable basis, comparable gross margin, comparable operating income, and EBITDA from period to period provides management and investors with supplemental information to evaluate earnings trends in comparison with results from prior periods. In calculating these items, we exclude the impact related to certain hedges that are either de-designated or deemed ineffective for accounting purposes, as management believes that these transactions are not representative of our business operations. As these gains (losses) have already been recognized in earnings in current or prior periods, future reported earnings will be lower; however, the expected cash flows from these contracts will not change. In calculating comparable earnings measures we have also excluded, as applicable, the inventory writedown, as the recognition of the writedown is related to the hedges that were de-designated or deemed ineffective during prior periods.

We have also excluded the impact of the asset impairment charges related to Centralia Thermal, which was determined based on the future cash flows expected to be derived from the plant's operations, the related writeoff of deferred income tax assets, the impacts of the Sundance Units 1 and 2 arbitration, and impairment charges recorded on assets in the renewables fleet.

Other one-time adjustments to earnings, such as the income tax expense related to changes in corporate income tax rates, the impact to revenue associated with Sundance Units 1 and 2, the income tax recovery related to the resolution of certain outstanding tax matters, the gain on sale of assets, the writeoff of Project Pioneer costs, the gain on sale of (reserve on) collateral, restructuring charges, the writeoff of wind development costs, and the writedown of certain capital spares, have also been excluded as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

Comparable operating income, EBITDA, and Comparable Return on Capital Employed ("ROCE")[1] also include the earnings from the finance lease facilities that we operate. The finance lease income is used as a proxy for the operating income, EBITDA, and ROCE of these facilities.

Net earnings on a comparable basis are reconciled to net earnings (loss) attributable to common shareholders below:

Year ended Dec. 31	2012	2011	2010
Net earnings (loss) attributable to common shareholders	(614)	290	255
Impacts associated with certain de-designated and ineffective hedges, net of tax	47	(81)	(28)
Asset impairment charges, net of tax	329	13	16
Restructuring charges, net of tax	10	–	–
Sundance Units 1 and 2 arbitration, net of tax	189	–	–
Income tax expense related to writeoff of deferred income tax assets	169	–	–
Income tax expense related to changes in corporate income tax rates	8	–	–
Income tax recovery related to the resolution of certain outstanding tax matters	(9)	–	(30)
Gain on sale of assets, net of tax	(2)	(12)	–
Writeoff of Project Pioneer costs, net of tax	2	–	–
(Gain on sale of) reserve on collateral, net of tax	(11)	13	–
Writeoff of wind development costs, net of tax	–	4	–
Writedown of capital spares, net of tax	–	3	–
Net earnings on a comparable basis	118	230	213
Weighted average number of common shares outstanding in the year	235	222	219
Net earnings on a comparable basis per share	0.50	1.04	0.97

Comparable Gross Margin

Comparable gross margin is calculated as follows:

Year ended Dec. 31	2012	2011	2010
Gross margin	1,453	1,716	1,488
Impacts associated with certain de-designated and ineffective hedges	72	(127)	(43)
Impacts to revenue associated with Sundance Units 1 and 2[2]	(20)	(40)	–
Inventory writedown	(25)	–	–
Comparable gross margin	1,480	1,549	1,445

Comparable Operating Income

A reconciliation of comparable operating income is as follows:

Year ended Dec. 31	2012	2011	2010
Operating income	42	645	459
Impacts associated with certain de-designated and ineffective hedges	72	(127)	(43)
Asset impairment charges	324	17	28
Restructuring charges	13	–	–
Finance lease income	16	8	8
Writeoff of Project Pioneer costs	3	–	–
Writeoff of wind development costs	–	6	–
Writedown of capital spares	–	4	–
Comparable operating income	470	553	452

1 This comparable item is not defined under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

2 The results have been adjusted retroactively for the impact of Sundance Units 1 and 2. Comparative figures have also been adjusted in this table only to provide period over period comparability.

Comparable EBITDA

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

A reconciliation of comparable EBITDA to operating income is as follows:

Year ended Dec. 31	2012	2011	2010
Operating income	42	645	459
Asset impairment charges	324	17	28
Finance lease income	16	8	8
Restructuring charges	13	–	–
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	564	532	511
Impacts associated with certain de-designated and ineffective hedges	72	(127)	(43)
Impacts to revenue associated with Sundance Units 1 and 2	(20)	(40)	–
Writeoff of Project Pioneer costs	3	–	–
Writeoff of wind development costs	–	6	–
Writedown of capital spares	–	4	–
Comparable EBITDA	**1,014**	1,045	963

Funds from Operations and Funds from Operations per Share

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

Year ended Dec. 31	2012	2011	2010
Cash flow from operating activities	520	690	852
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	204	–	–
Change in non-cash operating working capital balances	52	119	47
Funds from operations	776	809	805
Weighted average number of common shares outstanding in the year	235	222	219
Funds from operations per share	**3.30**	3.64	3.68

Free Cash Flow

Free cash flow represents the amount of cash generated by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments of debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash flow with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects.

Sustaining capital and productivity expenditures for the year ended Dec. 31, 2012 represent total additions to PP&E and intangibles per the Consolidated Statements of Cash Flows less $246 million that we have invested in projects and growth. In 2011, we invested $126 million ($124 million net of joint venture contributions).

1 *To calculate comparable EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in fuel and purchased power on the Consolidated Statements of Earnings.*

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

Year ended Dec. 31	**2012**	2011	2010
Cash flow from operating activities	**520**	690	852
Add (deduct):			
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**204**	–	–
Changes in non-cash operating working capital	**52**	119	47
Sustaining capital and productivity expenditures	**(496)**	(357)	(355)
Dividends paid on common shares[1]	**(104)**	(191)	(216)
Dividends paid on preferred shares	**(32)**	(15)	–
Distributions paid to subsidiaries' non-controlling interests	**(59)**	(61)	(62)
Free cash flow	**85**	185	172

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

Comparable ROCE

Comparable ROCE measures the efficiency and profitability of capital investments and is calculated by taking comparable earnings before net interest expense, non-controlling interests, and income taxes, and dividing by the average invested capital excluding AOCI. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods.

The calculation of comparable ROCE is presented below:

Year ended Dec. 31	**2012**	2011	2010
Net earnings (loss) attributable to common shareholders before income taxes per the Consolidated Statements of Earnings	**(443)**	449	304
Net interest expense	**242**	215	178
Non-controlling interest	**(37)**	(38)	(24)
Non-comparable items			
Impacts associated with certain de-designated and ineffective hedges	**72**	(127)	(43)
Asset impairment charges	**324**	17	28
Restructuring charges	**13**	–	–
Sundance Units 1 and 2 arbitration	**254**	–	–
Gain on sale of assets	**(3)**	(16)	–
Writeoff of Project Pioneer costs	**3**	–	–
(Gain on sale of) reserve on collateral	**(15)**	18	–
Writeoff of wind development costs	**–**	6	–
Writedown of capital spares	**–**	4	–
Comparable earnings before net interest expense, non-controlling interests, and income taxes	**410**	528	443
Average invested capital excluding AOCI	**7,708**	7,568	7,362
Comparable ROCE	**5.3**	7.0	6.0

1 *Net of dividends reinvested under the Plan.*

Selected Quarterly Information

	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Revenue	**656**	**407**	**538**	**661**
Net earnings (loss) attributable to common shareholders	**89**	**(797)**	**56**	**38**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.40**	**(3.51)**	**0.24**	**0.15**
Comparable earnings (loss) per share	**0.20**	**(0.10)**	**0.18**	**0.21**

	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Revenue	818	515	629	701
Net earnings attributable to common shareholders	204	12	50	24
Net earnings per share attributable to common shareholders, basic and diluted	0.92	0.05	0.22	0.11
Comparable earnings per share	0.34	0.29	0.27	0.13

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

Controls and Procedures

As required by Rule 13a-15 under the *Securities Exchange Act of 1934* ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2012, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Management's Report

To the Shareholders of TransAlta Corporation

The consolidated financial statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures, and established policies provide reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors ("the Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board carries out its responsibilities principally through its Audit and Risk Committee ("the Committee"). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors, and external auditors to discuss internal controls, auditing matters, and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.

Dawn Farrell
President and Chief Executive Officer

Brett Gellner
Chief Financial Officer

February 26, 2013

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the *United States Securities Exchange Act of 1934*).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta Corporation.

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO framework is a suitable framework for its evaluation of TransAlta Corporation's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta Corporation's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta Corporation's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

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

TransAlta Corporation proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint ventures and equity accounts for the CE Generation, LLC ("CE Gen") and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint ventures. Once the financial information is obtained from the joint ventures it falls within the scope of TransAlta Corporation's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of the joint ventures. The 2012 consolidated financial statements of TransAlta Corporation included $918 million and $883 million of total and net assets, respectively, as of December 31, 2012, and $208 million and $49 million of revenues and net earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at December 31, 2012, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta Corporation for the year ended December 31, 2012, has also issued a report on internal control over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn Farrell
President and Chief Executive Officer

Brett Gellner
Chief Financial Officer

February 26, 2013

Independent Auditors' Report on Internal Controls under Standards of the Public Company Accounting Oversight Board (United States)

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

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

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

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

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

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position of TransAlta Corporation as at December 31, 2012 and 2011 and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2012 and our report dated February 26, 2013, expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 26, 2013

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated statements of financial position as at December 31, 2012 and 2011, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2012, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2012 and 2011, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 26, 2013

Consolidated Statements of Earnings (Loss)

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

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

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

1 Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – nil, 2010 – nil).
2 Net of income tax expense of 2 for the year ended Dec. 31, 2012 (2011 – 5 recovery, 2010 – 6 expense).
3 Net of income tax of nil for the year ended Dec. 31, 2012 (2011 – nil, 2010 – nil).
4 Net of income tax expense of 3 for the year ended Dec. 31, 2012 (2011 – 7 recovery, 2010 – 87 expense).
5 Net of income tax recovery of 2 for the year ended Dec. 31, 2012 (2011 – nil, 2010 – 3 recovery).
6 Net of income tax expense of 20 for the year ended Dec. 31, 2012 (2011 – 94 expense, 2010 – 65 expense).
7 Net of income tax recovery of 10 for the year ended Dec. 31, 2012 (2011 – 9 recovery, 2010 – 7 recovery).

See accompanying notes.

Consolidated Statements of Financial Position

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

Contingencies *(Notes 36 and 39)*

Commitments *(Notes 17 and 38)*

See accompanying notes.

Gordon D Giffin   William D. Anderson

On behalf of the Board:

Gordon D. Giffin
Director

William D. Anderson
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

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

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

See accompanying notes.

Consolidated Statements of Cash Flows

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

See accompanying notes.

notes to consolidated financial statements

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

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or "the Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992 after TransAlta Utilities Corporation became a subsidiary.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation Segment owns and operates hydro, wind, geothermal, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("U.S."), and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support.

II. Energy Trading

The Energy Trading Segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

Energy Trading manages available generating capacity as well as the fuel and transmission needs of the Generation Segment by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of all of these activities are included in the Generation Segment.

III. Corporate

The Corporate Segment provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support to the Generation and Energy Trading Segments.

B. Basis of Preparation

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

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

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

C. Basis of Consolidation

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

2. Accounting Policies

A. Revenue Recognition

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

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

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

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

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

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

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

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

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

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

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

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

II. Hedges

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

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If the above hedge criteria are not met or the Corporation does not apply hedge accounting, the derivative is accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. Hedge effectiveness for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivatives' cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when it is not probable that the forecasted transaction will occur within the time period specified in the hedge documentation.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

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

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

D. Cash and Cash Equivalents

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

E. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

F. Inventory

I. Fuel

The Corporation's inventory balance is comprised of coal and natural gas used as fuel, which is measured at the lower of cost and net realizable value. Cost is determined using the weighted average cost method.

The cost of internally produced coal inventory is determined using absorption costing, which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower electricity production as maintenance is performed. Due to the limited number of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Trading

Commodity inventories held in the Energy Trading Segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

G. Property, Plant, and Equipment

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

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

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

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

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

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

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

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

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

H. Intangible Assets

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

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

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

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

Software	2-7 years
Power contracts	1-30 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

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

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

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

J. Goodwill

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

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs to which the goodwill relates is compared to the carrying amount of the CGUs. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

K. Project Development Costs

Project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the costs incurred subsequently are included in other assets. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

Compensation costs associated with awards under the Performance Share Ownership Plan ("PSOP") are accrued based on the fair value of each award, the service period completed, and the number of equivalent common shares eligible employees and directors have earned each period-end, which is based upon the percentile ranking of the total shareholder return of the Corporation's common shares in comparison to the total shareholder returns of companies comprising the comparative group.

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

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, these amounts are recognized as revenue in the period of recovery.

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

Q. Assets Held for Sale

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

R. Leases

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

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

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

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

S. Borrowing Costs

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

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

T. Non-Controlling Interests

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

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

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

U. Joint Ventures

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

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

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

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

V. Government Grants

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

W. Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of consolidated financial statements requires management to make judgments, estimates, and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses, and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation, and regulations.

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

I. Impairment of PP&E and Goodwill

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

II. Leases

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

III. Income Taxes

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

IV. Financial Instruments and Derivatives

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

V. Project Development Costs

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

VI. Provisions for Decommissioning and Restoration Activities

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

VII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

VIII. Employee Future Benefits

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

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

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

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

IX. Other Provisions

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

3. Accounting Changes

A. Current Year Accounting Changes

Change in Estimates – Useful Lives

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

B. Prior Year Accounting Changes

I. IFRS

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

II. Change in Estimates – Residual Values

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

C. Comparative Figures

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

D. Future Accounting Changes

I. Consolidated Financial Statements

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

II. Joint Arrangements

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

III. Disclosure of Interests in Other Entities

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

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

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

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

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

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

VI. Fair Value Measurement

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

VII. Presentation of Financial Statements

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

VIII. Employee Benefits

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

IX. Financial Instruments

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

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

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

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

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

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

XI. Offsetting Financial Assets and Liabilities

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

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

XII. Annual Improvements 2009-2011

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

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

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

4. Restructuring Charges

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

5. Acquisitions and Disposals

A. Acquisitions

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

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

B. Disposals

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

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. The sale was effective Jan. 1, 2011 and closed in April 2011, and resulted in the recognition of a pre-tax gain of $3 million in 2011.

6. Gain on Sale of (Reserve on) Collateral

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

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

7. Sundance Units 1 and 2 Arbitration

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

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

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

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

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

8. Expenses by Nature

Expenses classified by nature are as follows:

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

9. Leases

A. The Corporation as Lessor

I. Finance Leases

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

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

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

II. Operating Leases

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

B. The Corporation as Lessee

I. Operating Leases

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

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

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

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

10. Investments

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

The change in investments is as follows:

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

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

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

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

11. Asset Impairment Charges

A. Sundance Units 1 and 2

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

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

The losses and reversal are included in the Generation Segment.

B. Centralia Thermal

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

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

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

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

C. Renewables

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

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

D. Gas

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

E. Reversals

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

12. Net Interest Expense

The components of net interest expense are as follows:

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

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

13. Income Taxes

A. Consolidated Statements of Earnings (Loss)

I. Rate Reconciliations

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

II. Components of Income Tax Expense

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

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

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

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

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

B. Consolidated Statements of Changes in Equity

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

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

C. Consolidated Statements of Financial Position

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

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

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

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

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

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

D. Contingencies

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

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

14. Non-Controlling Interests

A. Consolidated Statements of Earnings (Loss)

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

B. Consolidated Statements of Financial Position

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

The change in non-controlling interests is as follows:

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

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

C. Consolidated Statements of Cash Flows

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

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

15. Accounts Receivable

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

The change in allowance for doubtful accounts is as follows:

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

16. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

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

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

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

1 *Includes current portion.*

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

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

1 *Includes current portion.*

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level Determinations and Classifications

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

a. Level I

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

b. Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes, in Level II, over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. *Level III*

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

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

TransAlta also has various contracts with terms that extend beyond a liquid trading period. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation Segments in relation to trading activities and certain contracting activities.

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

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

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

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

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

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

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

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt and the net investment in foreign operations, and similar non-hedge transactions.

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

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

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2010	–	(37)	–	–	1	–	–	(36)	–
Changes attributable to:									
Market price changes on existing contracts	–	25	–	–	–	–	–	25	–
New contracts	–	(34)	–	–	(1)	–	–	(35)	–
Contracts settled	–	(4)	–	–	–	–	–	(4)	–
Net risk management liabilities at Dec. 31, 2011	–	(50)	–	–	–	–	–	(50)	–

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

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

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

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

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

1 *Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, collateral paid, finance lease receivable, long-term receivable, accounts payable and accrued liabilities, collateral received, and dividends payable).*

2 *Includes current portion.*

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using valuation techniques or models. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes during the year is as follows:

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

17. Risk Management Activities

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

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

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

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

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

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

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

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

ii. Effect of Net Investment Hedges

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

Year ended Dec. 31, 2012			
Financial instruments in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) reclassified from OCI**	**Pre-tax (gain) reclassified from OCI**
Long-term debt	**19**	Foreign exchange	**–**
Foreign currency contracts	**(4)**	Foreign exchange	**–**
OCI impact	**15**	**OCI impact**	**–**

Year ended Dec. 31, 2011			
Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) reclassified from OCI	Pre-tax (gain) reclassified from OCI
Long-term debt	(23)	Foreign exchange	–
Foreign currency contracts	(15)	Foreign exchange	–
OCI impact	(38)	OCI impact	–

Year ended Dec. 31, 2010			
Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) reclassified from OCI	Pre-tax (gain) reclassified from OCI
Long-term debt	68	Foreign exchange	(3)
Foreign currency contracts	(29)	Foreign exchange	–
OCI impact	39	OCI impact	(3)

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

b. Cash Flow Hedges

i. Energy Trading Risk Management

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

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

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

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

ii. Foreign Currency Rate Risk Management

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

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

iii. Interest Rate Risk Management

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

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

iv. Effect of Cash Flow Hedges

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

Year ended Dec. 31, 2012

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

Year ended Dec. 31, 2011

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

Year ended Dec. 31, 2010

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

Over the next 12 months, the Corporation estimates that $13 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

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

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

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

ii. Effects of Fair Value Hedges

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

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

II. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management

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

b. Other Non-Hedge Derivatives

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

c. Total Return Swaps

The Corporation has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

d. *Effect of Non-Hedges*

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

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

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments.

I. Market Risk

a. *Commodity Price Risk*

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

The Corporation has a Commodity Exposure Management Policy (the "Policy") that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. The Policy defines and specifies the controls and management responsibilities associated with commodity activities, as well as the nature and frequency of required reporting of such activities.

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Trading Segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board of Directors approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2012 associated with the Corporation's proprietary energy trading activities was $2 million (2011 – $5 million, 2010 – $5 million).

ii. Commodity Price Risk – Generation

The Generation Segment utilizes various commodity contracts to manage the commodity price risk associated with its electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios, and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2012 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $5 million (2011 – $5 million, 2010 – $52 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2012 associated with these transactions was $9 million (2011 – $9 million, 2010 – $6 million).

b. *Interest Rate Risk*

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI, for the years ended Dec. 31, 2012, 2011, and 2010, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2012**		2011		2010	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
50 basis point change	**4**	**–**	4	(8)	4	–

1 *This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.*

c. *Currency Rate Risk*

The Corporation has exposure to various currencies, such as the Euro, the U.S. dollar, and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI, for the years ended Dec. 31, 2012, 2011, and 2010, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average five cent (2011 – six cent, 2010 – six cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2012**		2011		2010	
Currency	**Net earnings decrease**[1]	**OCI gain**[1,2]	Net earnings decrease[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
USD	**(2)**	**11**	(4)	11	(4)	9
AUD	**–**	**–**	–	–	1	–
EUR	**–**	**1**	–	3	–	–
Total	**(2)**	**12**	(4)	14	(3)	9

1 *These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.*
2 *The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.*

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Thermal PPAs as receivables are substantially all secured by letters of credit.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at Dec. 31, 2012:

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

The Corporation's maximum exposure to credit risk at Dec. 31, 2012, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables (see Note 36) and including the fair value of open trading, net of any collateral held, at Dec. 31, 2012 was $25 million (2011 – $38 million).

At Dec. 31, 2012, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at year-end. The Corporation has evaluated the risk of default related to this counterparty to be minimal.

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in Note 15.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong financial position and stable investment grade credit ratings.

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

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Exposure Management Committee, senior management, and the Board of Directors; and maintaining investment grade credit ratings.

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

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

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

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2012, the Corporation provided $19 million (2011 – $45 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At Dec. 31, 2012, the Corporation received $2 million (2011 – $16 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2012, the Corporation had posted collateral of $85 million (2011 – $62 million) in the form of letters of credit on derivative instruments primarily in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $77 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2012.

18. Restricted Cash

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

19. Inventory

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

The components of inventory are as follows:

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

The change in inventory is as follows:

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

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

No inventory is pledged as security for liabilities.

20. Income Taxes Receivable

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million. The appeal decision from the Federal Court was received on Jan. 20, 2012, and the ruling was in TransAlta's favour. The Crown had 60 days from the date of judgment to appeal the decision. No appeal was filed by the Crown. TransAlta has received $9 million in 2012, and expects to receive the remaining $2 million during the first quarter of 2013.

21. Property, Plant, and Equipment

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

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

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

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

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

22. Goodwill

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

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

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

Goodwill – Renewables

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

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

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

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

23. Intangible Assets

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

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

24. Other Assets

The components of other assets are as follows:

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

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts for projects no longer probable of occurring are charged to expense. In 2011, the Corporation wrote off $6 million of project development costs associated with the Saint-Valentin wind project.

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

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

25. Decommissioning and Other Provisions

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

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

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

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

A. Decommissioning and Restoration

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

B. Restructuring Provisions (see Note 4)

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

C. Other Provisions

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

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

26. Long-Term Debt

A. Amounts Outstanding

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

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*
2 *Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities. Includes U.S.$300 million at Dec. 31, 2012 (2011 – U.S.$300 million).*
3 *U.S. face value at Dec. 31, 2012 – U.S.$2.0 billion (2011 – U.S.$1.9 billion).*
4 *Includes U.S.$20 million at Dec. 31, 2012 (2011 – U.S.$20 million).*

A portion of the fixed rate components of the Corporation's debentures and senior notes have been hedged using fixed to floating interest rate swaps (see Note 17) and are recorded at fair value. The balance of long-term debt is not hedged and is recorded at amortized cost.

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's business. The facility is a four-year revolving credit facility that was last renewed in April 2012 and matures in 2016. The U.S.$300 million committed facility is a five-year facility that matures in 2013. Interest rates on the credit facilities vary depending on the option selected; Canadian prime, bankers' acceptances, U.S. LIBOR, or U.S. base rate, in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities, all of which mature in 2014. The Corporation anticipates renewing these facilities based on reasonable commercial terms, prior to their maturities.

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

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

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

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

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

TransAlta's debt contains terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2012, the Corporation was in compliance with all debt covenants.

B. Principal Repayments

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

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

C. Guarantees

Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2012 were $336 million (2011 – $328 million) with no (2011 – nil) amounts exercised by third parties under these arrangements.

27. Deferred Credits and Other Long-Term Liabilities

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

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

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

28. Common Shares

A. Issued and Outstanding

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

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

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

On Sept. 13, 2012, TransAlta completed a public offering of 19,250,000 common shares at a price of $14.30 per common share. TransAlta granted the underwriters an over-allotment option to purchase up to an additional 2,887,500 common shares at the same price. On Sept. 20, 2012, the underwriters exercised in part their over-allotment option and purchased an additional 1,992,000 common shares at $14.30 per common share for total gross proceeds of $304 million.

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The Shareholder Rights Plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and was last approved on April 29, 2010. As such, the Shareholder Rights Plan will be put before the Corporation's shareholders at the Corporation's Annual and Special Meeting of Shareholders on April 23, 2013 for a vote to be renewed, continued, ratified, and approved.

When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a Permitted Bid, where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

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

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

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

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

D. Earnings Per Share

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

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

E. Dividends

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

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

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

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Jan. 29, 2010	April 1, 2010	0.29	63	60	3
April 1, 2010	July 1, 2010	0.29	64	49	15
July 22, 2010	Oct. 1, 2010	0.29	63	46	17
Oct. 28, 2010	Jan. 1, 2011	0.29	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	48	17
Total		1.45	319		

29. Preferred Shares

A. Issued and Outstanding

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

Year ended Dec. 31, 2012

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

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

Year ended Dec. 31, 2011

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

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

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

The Series E preferred shareholders will have the right at their option to convert their shares into Series F Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2017 and on Sept. 30 of every fifth year thereafter. The holders of Series F preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 3.65 per cent.

On Nov. 30, 2011, TransAlta completed a public offering of 11 million Series C Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $275 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.15 per share as approved by the Board of Directors, payable quarterly, yielding 4.60 per cent per annum, for the initial period ending June 30, 2017. The dividend rate will reset on June 30, 2017 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.10 per cent. The preferred shares are redeemable at the option of TransAlta on or after June 30, 2017 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends.

The Series C preferred shareholders will have the right at their option to convert their shares into Series D Cumulative Redeemable Rate Reset First Preferred Shares on June 30, 2017 and on June 30 of every fifth year thereafter. The holders of Series D preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 3.10 per cent.

B. Dividends

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

Series A Cumulative Redeemable Rate Reset First Preferred Shares

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

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

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

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

Series C Cumulative Redeemable Rate Reset First Preferred Shares

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

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

Series E Cumulative Redeemable Rate Reset First Preferred Shares

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

30. Accumulated Other Comprehensive Income (Loss)

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

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

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

31. Share-Based Payment Plans

At Dec. 31, 2012, the Corporation had two types of share-based payment plans and an employee share purchase plan.

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

A. Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. U.S. Plan

This plan mirrors the rules of the Canadian plan and is offered to all full-time and part-time employees in the U.S.

III. Australian Phantom Plan

This plan is offered to all full-time and part-time employees in Australia below the level of manager. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

IV. Total Plan Information

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

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

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

Year ended Dec. 31	**2012**		2011		2010	
	Number of share options *(millions)*	**Weighted average exercise price** *($ per share)*	Number of share options *(millions)*	Weighted average exercise price *($ per share)*	Number of share options *(millions)*	Weighted average exercise price *($ per share)*
Outstanding, beginning of year	**1.7**	**25.10**	2.2	24.94	1.5	26.36
Granted	**-**	**-**	-	-	0.9	22.27
Exercised	**-**	**-**	-	-	(0.1)	16.20
Forfeited	**(0.2)**	**22.81**	(0.5)	25.35	(0.1)	26.61
Outstanding, end of year	**1.5**	**25.35**	1.7	25.10	2.2	24.94

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

No stock options were granted in 2012 or 2011. On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal instalments over four years starting Feb. 1, 2011 and expire after 10 years. The estimated weighted average fair value of these options granted was determined using the Black-Scholes option-pricing model and the following weighted average assumptions, resulting in a weighted average fair value of $3.63 per option:

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

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

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

B. Performance Share Ownership Plan

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to award to employees and directors up to an aggregate of 4.0 million common shares. During 2010, the authorized amount was increased to 6.5 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, cannot exceed 13.0 million common shares. Participants in the PSOP receive grants that, after three years, make them eligible to receive a set number of common shares, including the value of reinvested dividends over the period, or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. The ultimate awarding of PSOP in any year is at the discretion of TransAlta's Human Resource Committee ("HRC"). Once a participant's PSOP eligibility for an award has been established, 50 per cent of the shares may be released to the participant when the Board of Directors use share settlements on the awards, while the remaining 50 per cent will be held in trust for one additional year for employees below vice-president level, and for two additional years for employees at the vice-president level and above. If the awards are paid out in cash, they are paid immediately. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the Corporation's common shares amongst the companies comprising the comparator group. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued using the closing share price.

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

In 2012, pre-tax PSOP compensation expense was $3 million (2011 – $9 million, 2010 – $7 million), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss). In 2012, 55,418 common shares (2011 – 50,560, 2010 – 166,169 common shares) were issued at $15.12 per share (2011 – $21.15 per share, 2010 – $23.48 per share).

C. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2012, amounts receivable from employees under the plan totalled $4 million (Dec. 31, 2011 – $1 million).

32. Employee Future Benefits

A. Description

The Corporation has registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. The Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned.

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

The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $64 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuation of the Canadian and U.S. plans was as at Dec. 31, 2010 and Jan. 1, 2012, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2012.

B. Costs Recognized

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

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

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

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

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

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

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

The history of experience adjustments is as follows:

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

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

C. Status of Plans

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

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

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

D. Plan Assets

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

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

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

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

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

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

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

E. Defined Benefit Obligation

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

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

F. Contributions

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

	Registered	Supplemental	Other	Total
Expected employer contributions	9	5	2	16

G. Assumptions

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

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

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

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

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

The expected rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan.

H. Sensitivity Analysis

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

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

33. Joint Ventures

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

Jointly controlled assets	Ownership *(per cent)*	Description
Sheerness	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Fort Saskatchewan	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake	50	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power	50	Gas-fired plant in Australia operated by TransAlta
Genesee Unit 3	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	50	Coal-fired plant operated by TransAlta
Soderglen	50	Wind generation facilities in Alberta operated by TransAlta
Pingston	50	Hydro facility in British Columbia operated by TransAlta
Project Pioneer	25	Carbon capture and storage project (to be discontinued as announced in April 2012)

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

34. Changes in Non-Cash Operating Working Capital

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

35. Capital

TransAlta's capital is comprised of the following:

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

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

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

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

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

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

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

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

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. TransAlta monitors key credit ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and seeks to manage the Corporation's capital in line with the following targets:

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

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

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

These ratios are outlined below:

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

1 *Last 12 months.*

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

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

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

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

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

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

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

Periodically, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

During 2012, the Corporation issued 31.1 million common shares for total gross proceeds of $456 million. The Corporation also issued 9 million Series E Preferred Shares for total gross proceeds of $225 million.

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

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

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

36. Prior Period Regulatory Decision

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$47 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator, and the California Department of Water Resources during the 2000-2001 period. In addition, the California parties have sought additional refunds which to date have been rejected by FERC. TransAlta does not believe the California parties will be successful in obtaining additional refunds and is pursuing offsets from outstanding receivables to the refunds awarded by FERC. TransAlta established a U.S.$47 million provision to cover any potential refunds and continues to seek relief from these obligations. Final rulings are not expected in the near future.

37. Related-Party Transactions

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

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

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

Transactions with Key Management Personnel

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

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

38. Commitments

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

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

A. Natural Gas, Transportation, and Other Purchase Contracts

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

B. Transmission and Power Purchase Agreements

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

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

C. Coal Supply and Mining Agreements

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

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

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for repairs and maintenance that may be required on turbines at various wind generating facilities.

E. Growth, Major, and Development Project Commitments

Growth

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

Major

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

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

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

F. TransAlta Energy Bill Commitments

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

G. Other

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

39. Contingencies

TransAlta is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta.

40. Segment Disclosures

A. Description of Reportable Segments

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

Each segment assumes responsibility for its operating results to operating income (loss). Generation expenses include Energy Trading's intersegment charge for energy marketing. Energy Trading's operating expenses are presented net of these intersegment charges.

The accounting policies of the segments are the same as those described in Note 2. Intersegment transactions are accounted for on a cost-recovery basis that approximates market rates.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**2,259**	**3**	**–**	**2,262**
Fuel and purchased power	**809**	**–**	**–**	**809**
Gross margin	**1,450**	**3**	**–**	**1,453**
Operations, maintenance, and administration	**384**	**28**	**81**	**493**
Depreciation and amortization	**489**	**–**	**20**	**509**
Asset impairment charges	**324**	**–**	**–**	**324**
Inventory writedown	**44**	**–**	**–**	**44**
Restructuring charges	**5**	**–**	**8**	**13**
Taxes, other than income taxes	**27**	**–**	**1**	**28**
Intersegment cost allocation	**13**	**(13)**	**–**	**–**
Operating income (loss)	**164**	**(12)**	**(110)**	**42**
Finance lease income	**16**	**–**	**–**	**16**
Equity loss	**(15)**	**–**	**–**	**(15)**
Sundance Units 1 and 2 arbitration	**(254)**	**–**	**–**	**(254)**
Gain on sale of assets	**3**	**–**	**–**	**3**
Gain on sale of collateral	**–**	**15**	**–**	**15**
Other income				**1**
Foreign exchange loss				**(9)**
Net interest expense				**(242)**
Loss before income taxes				**(443)**

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

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

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

II. Selected Consolidated Statements of Financial Position Information

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

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

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

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

III. Selected Consolidated Statements of Cash Flows Information

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

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

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

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

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

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

C. Geographic Information

I. Revenues

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

II. Non-Current Assets

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

eleven-year financial and statistical summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	**2012**	2011	2010
Financial Summary			
Statement of Earnings			
Revenues	**2,262**	2,663	2,673
Operating income	**42**	645	487
Net earnings (loss) attributable to common shareholders	**(614)**	290	255
Statement of Financial Position			
Total assets	**9,451**	9,729	9,635
Current portion of long-term debt, net of cash and cash equivalents	**580**	267	202
Long-term debt	**3,610**	3,721	3,823
Other non-controlling interests	**330**	358	431
Preferred securities	**–**	–	–
Equity attributable to shareholders	**3,010**	3,269	3,120
Total invested capital	**7,530**	7,615	7,576
Cash Flows			
Cash flow from operating activities	**520**	690	838
Cash flow used in investing activities	**(1,048)**	(608)	(765)
Common Share Information *(per share)*			
Net earnings (loss)	**(2.61)**	1.31	1.16
Comparable earnings[3]	**0.50**	1.04	0.97
Dividends paid on common shares	**1.16**	1.16	1.16
Book value *(at year-end)*	**8.75**	12.08	12.85
Market price:			
High	**21.37**	23.24	23.98
Low	**14.11**	19.45	19.61
Close *(Toronto Stock Exchange at Dec. 31)*	**15.12**	21.02	21.15
Ratios *(percentage except where noted)*			
Debt to invested capital	**55.7**	52.5	53.1
Debt to invested capital excluding non-recourse debt	**53.3**	50.0	50.7
Return on equity attributable to common shareholders	**(23.7)**	10.6	9.6
Comparable return on equity attributable to common shareholders[3]	**4.6**	8.4	8.0
Return on capital employed	**(3.1)**	8.3	6.6
Comparable return on capital employed[3]	**5.3**	7.0	6.0
Price to comparable earnings ratio	**30.2**	20.2	21.8
Earnings coverage *(times)*	**(1.2)**	2.7	2.2
Dividend payout ratio based on net earnings	**(44.1)**	66.9	125.1
Dividend payout ratio based on comparable earnings[3]	**229.7**	84.3	149.8
Dividend payout ratio based on funds from operations[3,4]	**34.9**	24.0	39.6
Comparable EBITDA *(in millions of Canadian dollars)*[3]	**1,014**	1,045	955
Dividend coverage *(times)*	**6.7**	3.5	4.0
Dividend yield	**7.7**	5.5	5.5
Adjusted cash flow to debt[4]	**18.9**	20.1	19.6
Adjusted cash flow to interest coverage *(times)*[4]	**4.4**	4.4	4.6
Weighted average common shares for the year *(in millions)*	**118**	230	219
Common shares outstanding at Dec. 31 *(in millions)*	**255**	224	220
Statistical Summary			
Number of employees	**2,084**	2,235	2,389
Generating Capacity *(net MW)*[5]			
Coal	**4,351**	4,325	4,688
Gas	**1,532**	1,532	1,613
Renewables	**1,973**	1,974	1,950
Finance lease	**390**	390	390
Equity investments	**35**	35	35
Total generating capacity	**8,281**	8,256	8,676
Total generation production *(GWh)*[6]	**38,750**	41,012	48,614

Financial data presented is based on IFRS. Financial data for 2009 and prior is based on Canadian GAAP. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

1 *2002 Energy Trading real-time contract revenues are restated to be presented on a gross basis.*
2 *Includes discontinued operations.*
3 *These ratios were calculated using non-IFRS measures. Periods for which the non-IFRS measure was not previously disclosed have not been calculated.*
4 *Adjusted for the impacts associated with Sundance Units 1 and 2 arbitration.*
5 *Represents TransAlta's ownership.*
6 *Includes discontinued operations.*

Ratio Formulas

Debt to invested capital = long-term debt including current portion – cash and cash equivalents / long-term debt including current portion + non-controlling interests + equity attributable to shareholders – cash and cash equivalents

Return on equity attributable to common shareholders = net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / average equity attributable to common shareholders excluding Accumulated Other Comprehensive Income (AOCI)

Earnings coverage = net earnings attributable to common shareholders + income taxes + net interest expense / interest on debt – interest income

2009	2008	2007	2006	2005	2004	2003	2002
2,770	3,110	2,775	2,677	2,664	2,838	2,509	1,815[1]
378	533	541	157	421	478	554	224[2]
181	235	309	45	199	170	234	190
9,762	7,815	7,157	7,460	7,741	8,133	8,420	7,420
(51)	194	600	296	(66)	(103)	(35)	146
4,411	2,564	1,837	2,221	2,605	3,058	3,162	2,707
478	469	496	535	559	616	478	263
–	–	–	175	175	175	451	452
2,929	2,510	2,299	2,428	2,543	2,473	2,460	2,040
7,767	5,737	5,232	5,655	5,756	6,061	6,516	5,608
580	1,038	847	490	619	613	757	438
(1,598)	(581)	(410)	(261)	(242)	(65)	(535)	(36)
0.90	1.18	1.53	0.22	1.01	0.88	1.26	1.12
0.90	1.46	1.31	1.16	0.88	0.70	0.69	0.99
1.16	1.08	1.00	1.00	1.00	1.00	1.00	1.00
13.41	12.70	11.39	11.99	12.80	12.74	12.90	12.01
25.30	37.50	34.00	26.91	26.66	18.75	19.55	23.95
18.11	21.00	23.79	20.22	17.67	15.25	15.36	16.69
23.48	24.30	33.35	26.64	25.41	18.05	18.53	17.11
56.1	48.1	46.8	44.5	43.9	47.4	47.9	50.9
52.6	45.6	44.0	41.0	39.9	42.5	42.9	–
6.9	9.4	13.1	1.8	7.0	6.5	10.3	3.5
6.9	11.6	10.5	9.2	6.8	5.1	5.6	8.2
5.7	7.7	9.8	2.4	7.1	7.5	9.1	4.0
5.8	9.6	9.7	9.0	7.4	–	–	–
26.1	20.6	21.8	121.1	26.7	21.7	14.7	41.7
1.9	2.8	3.3	0.5	2.3	1.9	2.0	1.9
129.8	91.5	65.6	447.7	113.0	120.0	79.0	241.8
129.8	74.1	76.4	86.0	113.3	150.4	143.7	100.6
–	–	–	–	–	–	–	–
888	1,006	980	–	–	–	–	–
2.6	4.8	4.2	2.4	3.1	3.2	4.1	2.6
4.9	4.4	3.0	3.8	3.9	5.5	5.4	5.8
20.5	31.7	30.7	26.2	23.0	18.5	17.9	16.1
4.9	7.2	6.6	5.5	4.7	4.1	3.3	3.8
201	199	202	201	197	193	185	170
218	198	201	202	199	194	191	170
2,343	2,200	2,201	2,687	2,657	2,505	2,563	2,573
4,967	4,942	4,942	4,887	4,885	4,778	4,777	4,966
1,843	1,913	1,960	1,953	1,933	2,444	2,499	1,333
1,965	1,218	1,122	1,122	1,117	1,115	1,046	845
–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–
8,775	8,073	8,024	7,962	7,935	8,337	8,322	7,144
45,736	48,891	50,395	48,213	51,810	54,560	53,134	46,877

Return on capital employed = earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense / average annual invested capital excluding AOCI

Dividend yield = dividend per common share / current year's close price

Dividend payout ratio = common share dividends / net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis or funds from operations

Price to comparable earnings ratio = current year's close price / comparable earnings per share

Adjusted cash flow to interest coverage = cash flow from operating activities before changes in working capital + interest on debt – interest income – capitalized interest / interest on debt – interest income

Dividend coverage = cash flow from operating activities / cash dividends paid on common shares

Adjusted cash flow to debt = cash flow from operating activities before changes in working capital / two-year average of total debt – average cash and cash equivalents

Comparable EBITDA = operating income + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

shareholder information

Annual Meeting

The Annual and Special Meeting of Shareholders will be held at 1:00 p.m. MDT on Tuesday, April 23, 2013, at the Metropolitan Conference Centre, 333 Fourth Avenue S.W., Calgary, Alberta.

Transfer Agent

CIBC Mellon Trust Company[1]
c/o Canadian Stock Transfer Company Inc.
P.O. Box 700 Station "B"
Montreal, Quebec H3B 3K3

Phone
North America:
1.800.387.0825 toll-free
Toronto/outside North America:
416.682.3860

E-mail
inquiries@canstockta.com

Fax
514.985.8843

Website
www.canstockta.com

Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares:
TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares:
TSX: TA.PR.D, TA.PR.F, TA.PR.H

1 On November 1, 2010, CIBC Mellon Trust Company sold its issuer services business to Canadian Stock Transfer Company Inc. ("CST"). CST and American Stock Transfer & Trust Company, LLC (AST) form the North American division of the Link Group, an international network of providers of transfer agent and employee plan services. With offices in Toronto, Montreal, Calgary, Halifax and Vancouver, CST provides global solutions through local access points.

Special Services for Registered Shareholders

Service	Description
Premium Dividend™ Dividend Reinvestment and Optional Share Purchase Plan[1]	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs or, as provided under the Plan obtain a cash return equivalent to 102 per cent of your dividend under the Premium Dividend™ Component of the Plan
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.

1 Also available to non-registered shareholders.

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split[2]
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares[3] 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.

2 The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988 share split.

3 TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. In determining the level of the dividend, the Board assesses the dividend payout as a percentage of earnings and as a percentage of cash flow from operations over a period of time. Dividends are at the discretion of the Board. In determining the dividend, the Board considers the Corporation's financial performance, its results of operations, cash flow, and needs with respect to financing ongoing operations and growth balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

Common Share Dividends Declared

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2012	March 1, 2012	Feb. 28, 2012	$0.29
July 1, 2012	June 1, 2012	May 30, 2012	$0.29
Oct. 1, 2012	Sept. 1, 2012	Aug. 29, 2012	$0.29
Jan. 1, 2013	Nov. 30, 2012	Nov. 28, 2012	$0.29
April 1, 2013	March 1, 2013	Feb. 27 2013	$0.29

Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Dec. 10, 2010 to, but excluding, March 31, 2016.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Nov. 29, 2011 to, but excluding, June 30, 2017.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.25 per share from the date of issue Aug. 10, 2012 to, but excluding, September 30, 2017.

Preferred Share Dividend Declared

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2012	March 1, 2012	Feb. 28, 2012	$0.2875
June 30, 2012	June 1, 2012	May 30, 2012	$0.2875
Sept. 30, 2012	Sept. 1, 2012	Aug. 29, 2012	$0.2875
Dec. 31, 2012	Nov. 30, 2012	Nov. 28, 2012	$0.2875
March 31, 2013	March 1, 2013	Feb. 27, 2013	$0.2875

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2012	March 1, 2012	Feb. 28, 2012	$0.3844[1]
June 30, 2012	June 1, 2012	May 30, 2012	$0.2875
Sept. 30, 2012	Sept. 1, 2012	Aug 29, 2012	$0.2875
Dec. 31, 2012	Nov. 30, 2012	Nov. 28, 2012	$0.2875
March 31, 2013	March 1, 2013	Feb. 27, 2013	$0.2875

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
Dec. 31, 2012	Nov. 30, 2012	Nov. 28, 2012	$0.4897[2]
March 31, 2013	March 1, 2013	Feb. 27, 2013	$0.3125

Dividends are paid on the last day of the month in March, June, September, and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

1 The first quarterly dividend payable is based on a longer period, starting from the issue date of Nov. 29, 2011 to March 31, 2012.

2 The first quarterly dividend payable is based on a longer period, starting from the issue date of Aug. 10, 2012 to Dec. 31, 2012.

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Vice-President & Corporate Secretary of the Corporation.

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:

Investor Relations
TransAlta Corporation
110 - 12th Avenue SW
Box 1900, Station "M"
Calgary, Alberta
Canada T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

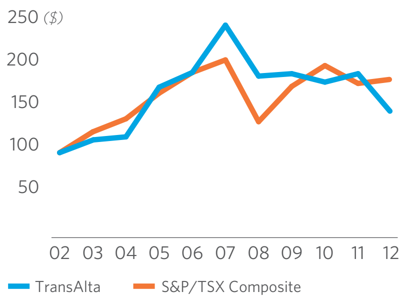
E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

shareholder highlights

Total Shareholder Return vs. S&P/TSX Composite Index



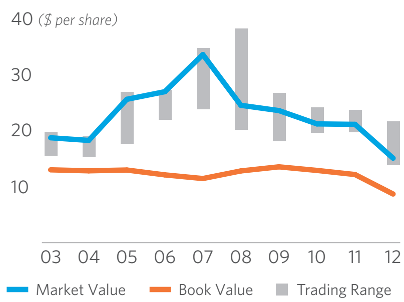
Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*	02	03	04	05	06	07	08	09	10	11	12
TransAlta	100	115	119	177	193	251	189	193	183	193	148
S&P/TSX Composite	100	124	140	170	195	209	136	178	203	181	186

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2002 would be worth today, assuming the reinvestment of all dividends.

Source: Thomson Financial

Ten-year Trading Range and Market Value vs. Book Value



Ten-year Trading Range and Market Value vs. Book Value

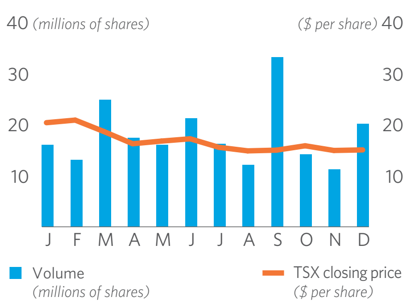
Year ended Dec. 31

($ per share)	03	04	05	06	07	08	09	10	11	12
Market Value	18.53	18.05	25.41	26.64	33.35	24.30	23.48	21.15	21.02	15.12
Book Value	12.90	12.74	12.80	11.99	11.39	12.70	13.41	12.85	12.08	8.76

Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).

Source: Thomson Financial and TransAlta (MD&A)

Monthly Volume and Market Price

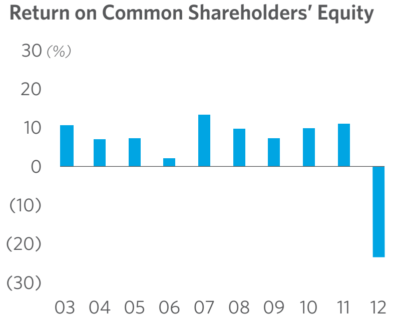


Monthly Volume and Market Prices

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume *(millions)*	16	13	25	17	16	21	16	12	33	14	11	20
TSX closing price	20.36	20.89	18.70	16.38	16.85	17.25	15.65	14.89	15.05	15.92	14.95	15.12

Source: Thomson Financial

Return on Common Shareholders' Equity



Return on Common Shareholders' Equity

(%)	03	04	05	06	07	08	09	10	11	12
ROE	10.3	6.5	7.0	1.8	13.1	9.4	6.9	9.6	10.6	(23.6)

Amounts prior to 2009 have not been restated for IFRS.

Source: TransAlta (MD&A)

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair, Committee Chair, President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Ethics Help-Line

The Audit and Risk Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number, fax line and email address for employees, contractors, shareholders, and other stakeholders to call with respect to accounting irregularities, ethical violations, or any other matters they wish to bring to the attention of the Board.

The Ethics Help-Line number is **1.888.806.6646**
Fax: **403.267.7985**
E-mail: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to
corporate_secretary@transalta.com

TransAlta Corporate Officers

Dawn Farrell
President and Chief Executive Officer

Paul Taylor
President, U.S. Operations

Ken Stickland
Chief Business Development Officer

John Kousinioris
Chief Legal and Compliance Officer

Brett Gellner
Chief Financial Officer

Dawn de Lima
Chief Human Resources and Communications Officer

Rob Schaefer
Executive Vice-President, Corporate Development

Cynthia Johnston
Executive Vice-President, Corporate Services

Hugo Shaw
Executive Vice-President, Operations

Robert (Bob) Emmott
Chief Engineer

David J. Koch
Vice-President, Controller

Maryse St.-Laurent
Vice-President and Corporate Secretary

Todd Stack
Vice-President and Treasurer

glossary

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.

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.

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

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

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.

CO_2 Emissions Intensity: Amount of carbon dioxide emitted per MWh produced.

Coal Gasification: The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen, or a variety of other chemical products.

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.

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

Expected Capability: Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

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.

Gigajoule (GJ): A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW): 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.

Heat Rate: A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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.

Merchant Assets: Assets that have contracts with terms less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short- and medium-term contracts.

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

North American Electric Reliability Corporation (NERC): The Northern American Electric Reliability Council. An association for regional councils, which provides coordination and planning. A non-profit organization formed by the electric utility industry to ensure a reliable, adequate power supply in North America. NERC plays an important role in establishing the standards, rules and forms of cooperation that contribute to system reliability.

Penstock: A component of a hydropower plant; a pipe that delivers water to the turbine.

Power Purchase Arrangements (PPA): A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Renewable Power: Power generated from renewable terrestrial mechanisms including wind, geothermal and solar.

Reserve Margin: An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Spark Spread: A measure of gross margin per MW (sales price less cost of natural gas).

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.

Target Zero: TransAlta's initiative designed to drive health, safety, and environmental performance to zero lost-time, medical aid, and environmental incidents.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround: Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage: The shutdown of a generating unit due to an unanticipated breakdown.

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.

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