# TransAlta Management's Discussion and Analysis

*December 31, 2012*

# 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

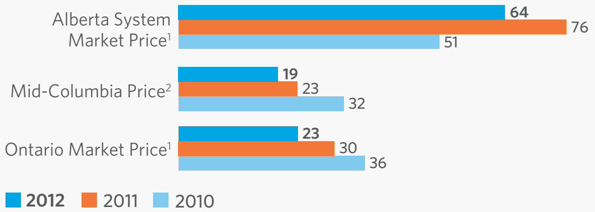
The economic environment showed signs of weakness during 2012 and in 2013 we expect slow to moderate growth in Alberta and Australia, and low growth in other markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

## 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.

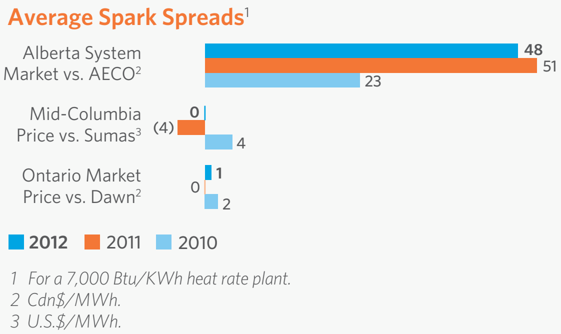
Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, and the other business environment dynamics discussed above. We monitor these trends in prices, and schedule maintenance, where possible, during times of lower prices.

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.

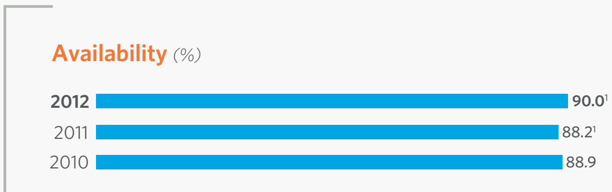
## People

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.

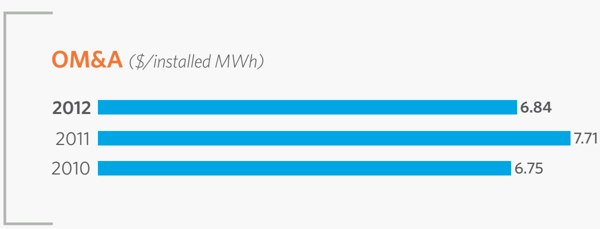
We strive to optimize the availability of our plants throughout the year to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, as well as by reduced production as a result of derates. Our goal is to minimize these 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



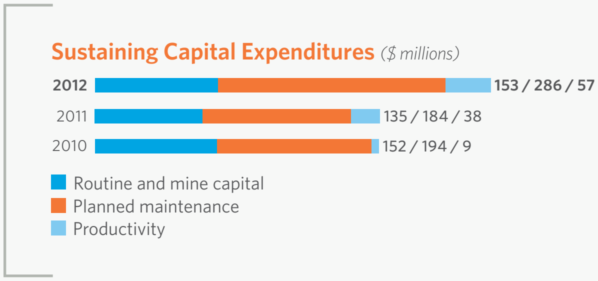

Our OM&A costs reflect the operating cost of our facilities. These costs can fluctuate due to the timing and nature of planned maintenance activities. The remainder of OM&A costs reflects the cost of day-to-day operations. Our target is to offset the impact of inflation in our recurring operating costs 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.