TransAlta™

TransAlta Corporation

Management's Discussion and Analysis

December 31, 2013

Plant Summary

As of January 31, 2014	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1,2]	Fuel	Revenue source	Contract expiry date
Western Canada 39 Facilities	Sundance, AB[3]	2,141	100%	2,141	Coal	Alberta PPA[4]/Merchant[5]	2017-2020
	Keephills, AB	790	100%	790	Coal	Alberta PPA/Merchant[6]	2020
	Genesee 3, AB	466	50%	233	Coal	Merchant	–
	Keephills 3, AB	463	50%	232	Coal	Merchant	–
	Sheerness, AB	780	25%	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100%	356	Gas	LTC[7]/Merchant	2023
	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	Merchant	–
	Horseshoe, AB	14	100%	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100%	13	Hydro	Alberta PPA	2020
	Taylor, AB	13	81%	10	Hydro	Merchant	–
	Interlakes, AB	5	100%	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	81%	2	Hydro	Merchant	–
	Three Sisters, AB	3	100%	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	81%	2	Hydro	Merchant	–
	St. Mary, AB	2	81%	2	Hydro	Merchant	–
	Upper Mamquam, BC	25	81%	20	Hydro	LTC	2025
	Pingston, BC	45	40%	18	Hydro	LTC	2023
	Bone Creek, BC	19	81%	15	Hydro	LTC	2031
	Akolkolex, BC	10	81%	8	Hydro	LTC	2015
	Summerview 1, AB	70	81%	57	Wind	Merchant	–
	Summerview 2, AB	66	81%	53	Wind	Merchant	–
	Ardenville, AB	69	81%	56	Wind	Merchant	–
	Blue Trail, AB	66	81%	53	Wind	Merchant	–
	Castle River, AB[8]	44	81%	35	Wind	Merchant	–
	McBride Lake, AB	75	40%	30	Wind	LTC	2023
	Soderglen, AB	71	40%	28	Wind	Merchant	–
	Cowley Ridge, AB	21	100%	21	Wind	Merchant	–
	Cowley North, AB	20	81%	16	Wind	Merchant	–
	Sinnott, AB	7	81%	5	Wind	Merchant	–
	Macleod Flats, AB	3	81%	2	Wind	Merchant	–
Total Western Canada		**6,546**		**5,219**			
Eastern Canada 16 Facilities	Sarnia, ON	506	100%	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50%	54	Gas	LTC	2018
	Ottawa, ON	74	50%	37	Gas	LTC	2017-2033
	Windsor, ON	68	50%	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100%	7	Hydro	Merchant	–
	Misema, ON	3	81%	2	Hydro	LTC	2027
	Galetta, ON	2	81%	2	Hydro	LTC	2030
	Appleton, ON	1	81%	1	Hydro	LTC	2030
	Moose Rapids, ON	1	81%	1	Hydro	LTC	2030
	Wolfe Island, ON	198	81%	160	Wind	LTC	2029
	Melancthon, ON[9]	200	81%	161	Wind	LTC	2026-2028
	Le Nordais, QC	99	100%	99	Wind	LTC	2033
	Kent Hills, NB[9]	150	67%	100	Wind	LTC	2033-2035
	New Richmond, QC	68	81%	55	Wind	Québec PPA	2033
Total Eastern Canada		**1,484**		**1,219**			
United States 18 Facilities	Centralia, WA	1,340	100%	1,340	Coal	LTC/Merchant	2025
	Centralia Gas, WA[10]	248	100%	248	Gas	Merchant	–
	Power Resources Inc., TX	212	50%	106	Gas	Merchant	–
	Saranac, NY	240	37.5%	90	Gas	Merchant	–
	Yuma, AZ	50	50%	25	Gas	LTC	2024
	Skookumchuck, WA	1	100%	1	Hydro	LTC	2020
	Wailuku, HI	10	50%	5	Hydro	LTC	2023
	Wyoming Wind, WY	144	81%	116	Wind	LTC	2028
	Imperial Valley, CA[11]	340	50%	170	Geothermal	LTC	2016-2039
Total U.S.		**2,585**		**2,101**			
Australia 6 Facilities	Parkeston, WA	110	50%	55	Gas	LTC	2016
	Southern Cross, WA[12]	245	100%	245	Gas/Diesel	LTC	2023
	Solomon Power Station, WA	125	100%	125	Gas/Diesel	LTC	2028
Total Australia		**480**		**425**			
Total		**11,095**		**8,964**			

1 *Megawatts are rounded to the nearest whole number; columns may not add due to rounding.*
2 *Accounts for TransAlta's 80.7% ownership of TransAlta Renewables.*
3 *Includes a 15 MW uprate on Sundance unit 3; the resulting increased capacity will not be realized until the generator stator is replaced.*
4 *PPA refers to Power Purchase Agreement*
5 *Merchant capacity refers to uprates on unit 4 (53 MW), unit 5 (53 MW), and unit 6 (44 MW).*
6 *Merchant capacity refers to uprates on unit 1 (12 MW) and unit 2 (12 MW).*
7 *LTC refers to Long-Term Contract.*
8 *Includes seven individual turbines at other locations.*
9 *Comprised of two facilities.*
10 *The plant is currently not in operation. The Corporation is currently assessing the generation needs of the region and the financial feasibility of bringing the plant back into operation.*
11 *Comprised of ten facilities.*
12 *Comprised of four facilities.*

Management's Discussion and Analysis

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*This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited 2013 consolidated financial statements and our 2014 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. 20, 2014. 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

Strategic Highlights

Financial Flexibility and Positioning for Growth

- TAMA Transmission LP ("TAMA Transmission") successfully qualified to participate as a proponent in the Fort McMurray West 500 kilovolt Transmission Project.
- Formation of TransAlta Renewables Inc. ("TransAlta Renewables"), creating a vehicle for enhancing TransAlta's strategy for growth in contracted and operating assets.

Long-Term Stability of Cash Flows

- Long-term contract extension to supply power to the BHP Billiton Nickel West operations in Western Australia.
- 50 megawatt ("MW") long-term contract with the Salt River Project signed by CalEnergy, LLC ("CalEnergy").
- 74 MW 20-year long-term power supply contract with the Ontario Power Authority ("OPA") for our Ottawa facility.
- 86 MW long-term contract with the City of Riverside signed by CalEnergy.
- Approval of long-term contract with Puget Sound Energy ("PSE") at Centralia Thermal.

Growth

- Announced plans to build and own (TransAlta ownership 43 per cent) a $178 million natural gas pipeline to our Solomon power station.
- Acquired 144 MW wind farm in Wyoming.
- Began commercial operations of our 68 MW long-term contracted New Richmond wind farm.

Operational Financial Results

- Consolidated: Comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA") for 2013 increased $8 million to $1,023 million. The improvements in the wind, hydro, gas, trading, and corporate segments were partially offset by a decline in comparable EBITDA from our Canadian and U.S. coal operations. Lower realized prices and higher coal costs at Canadian Coal facilities and lower pricing at Centralia Thermal contributed to the bulk of the decline in the coal business in 2013.
- Canadian Coal: In 2013, comparable EBITDA was $309 million compared to $373 million in 2012 and $273 million in 2011. The main impact to the business in 2013 was lower realized prices, higher penalties, and higher coal costs. We also took over the Highvale Mine in 2012 and needed to expand the mine to be able to deliver coal to all six Sundance units and all three Keephillls units. Planned major maintenance for this business sector has returned to normal levels after a large capital program in 2012 was completed.
- U.S. Coal: Comparable EBITDA decreased to $66 million in 2013 compared to $148 million in 2012 and $211 million in 2011. The decline in comparable EBITDA is due to weak merchant pricing and expiry of contracts through the 2011 to 2013 period. Lower fuel and purchased power cost in 2013 reflect re-negotiated rail costs, and capital was reduced significantly due to the long period of economic curtailment of these units under low prices.
- Gas: Comparable EBITDA increased by $15 million to $327 million primarily due to a full year of income from the Solomon power station that was acquired in August 2012, partially offset by higher operations, maintenance, and administration ("OM&A") costs resulting from higher routine maintenance. Capital expenditures in this business were $58 million, up $9 million compared to 2012, and down $11 million compared to 2011. These are relatively normal run rates for capital for this business.
- Wind: Comparable EBITDA for wind improved by $29 million in 2013 to $180 million, primarily due to higher prices in the Alberta market and commencement of operations at the New Richmond facility in Québec.
- Hydro: Comparable EBITDA increased by $20 million to $147 million, primarily due to favourable pricing in the Alberta market.
- Equity Investments: The geothermal business, which is recorded within equity investments, lost $10 million in 2013 compared to a loss of $15 million in 2012. The reduction of the loss is primarily due to favourable prices in 2013 relative to 2012.
- Energy Trading Segment: Our Energy Trading business showed an improvement in comparable EBITDA of $74 million in 2013 to $61 million. Tighter risk controls and additional asset optimization capability contributed to the turnaround in this business.
- Corporate Segment: OM&A improved by $16 million due to savings achieved through the restructuring in 2012.
- Overall availability, including finance leases and equity investments, was 85.5 per cent compared to 88.4 per cent in 2012. Adjusting for economic dispatching at Centralia Thermal, availability was 87.8 per cent compared to 90.0 per cent in 2012. The decrease is mainly due to higher unplanned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities, primarily driven by the Keephills Unit 1 force majeure outage, partially offset by lower planned outages at the Alberta coal facilities.
- Overall production increased 3,732 gigawatt hours ("GWh") to 42,482 GWh compared to 2012.

Consolidated Highlights

- Funds from operations ("FFO") decreased $59 million to $729 million compared to 2012, primarily due to higher cash interest and cash taxes as well as differences in timing of cash proceeds associated with power hedges.
- Comparable earnings were $81 million ($0.31 per share), down from $117 million ($0.50 per share) in 2012. The decrease in comparable earnings is primarily due to an increase in depreciation and amortization, income taxes, and net interest, partially offset by an increase in comparable EBITDA.
- Reported net loss attributable to common shareholders was $71 million ($0.27 net loss per share), up from net loss attributable to common shareholders of $615 million ($2.62 net loss per share) in 2012. The change is driven by an increase in comparable EBITDA of $8 million and the following non-comparable amounts, net of tax:
  - Decrease in asset impairment charges of $342 million
  - Decrease in impact of Sundance Units 1 and 2 return to service of $170 million
  - Decrease in impact of writeoff of deferred income tax assets of $141 million
  - Increase in impact of the California claim of $42 million
  - Increase in loss on assumption of pension obligations of $22 million due to the assumption of mining operations at the Highvale Mine and related pension obligations for mine employees
  - Increase in loss on de-designated hedges of $20 million
  - Decrease in restructuring provision of $12 million
  - Decrease in gain on sale of collateral of $11 million
- We have accrued for a potential settlement with San Diego Gas & Electric Company, the California Attorney General, and other government agencies with a pre-tax impact of U.S.$52 million.

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

Year ended Dec. 31	**2013**	2012	2011
Availability *(%)*[1]	**85.5**	88.4	85.4
Adjusted availability *(%)*[1,2]	**87.8**	90.0	88.2
Production *(GWh)*[1]	**42,482**	38,750	41,012
Revenues	**2,292**	2,210	2,618
Comparable EBITDA[3]	**1,023**	1,015	1,044
Net earnings (loss) attributable to common shareholders	**(71)**	(615)	290
Comparable net earnings attributable to common shareholders[3]	**81**	117	232
Funds from operations[3]	**729**	788	812
Cash flow from operating activities	**765**	520	690
Free cash flow[3]	**295**	258	417
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.27)**	(2.62)	1.31
Comparable earnings per share[3]	**0.31**	0.50	1.05
Funds from operations per share[3]	**2.76**	3.35	3.66
Free cash flow per share[3]	**1.12**	1.10	1.88
Dividends paid per common share	**1.16**	1.16	1.16

As at Dec. 31	**2013**	2012
Total assets	**9,783**	9,503
Total long-term liabilities	**5,508**	4,769

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 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.*

Comparable EBITDA is as follows:

Year ended Dec. 31	2013	2012	2011
Generation Segment			
Canadian Coal	**309**	373	273
U.S. Coal	**66**	148	211
Gas	**327**	312	275
Wind	**180**	151	163
Hydro	**147**	127	105
Total Generation Segment	**1,029**	1,111	1,027
Energy Trading Segment	**61**	(13)	101
Corporate Segment	**(67)**	(83)	(84)
Total comparable EBITDA	**1,023**	1,015	1,044

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 use a broad range of generation fuels including coal, natural gas, hydro, wind, and geothermal. During 2013, commercial operations began at our New Richmond wind farm and Sundance Units 1 and 2 were returned to service. We added an additional 628 MW of power to our generation portfolio as a result of these projects, increasing our gross generating capacity[1] to 9,046 MW[2] (8,453 MW net ownership interest). Please refer to the Significant Events section of this MD&A for more information.

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, among other things, 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.

Alberta has seen annual average demand growth of about three per cent over the past three years. Investment in oil sands development is a key driver of electricity demand growth in the province, and several large projects are under way that should bring new demand over the next several years. In the Pacific Northwest and Ontario, demand growth was relatively flat in 2013.

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 2013, reserve margins in Alberta increased as a result of Sundance Units 1 and 2 returning to service and reserve margins were relatively flat in the Pacific Northwest. In Ontario, reserve margins decreased primarily due to the retirement of coal generation capacity, which was partially offset by the effect of nuclear generating plants returning to service at the end of 2012.

Renewable generation growth has been strong in all regions for the past several years. In 2013, neither Alberta nor the Pacific Northwest increased wind capacity; however, both regions completed small biomass projects. Ontario continues to develop wind and solar capacity through its Feed-in Tariff program and increased renewable capacity by over 1,000 MW in 2013.

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.

2 All Generation assets excluding equity investments.

Transmission

Transmission refers to the bulk delivery system of power and energy between generating units and consumers. 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 access to markets until key bulk transmission upgrades and additions are completed.

Alberta

Transmission development in Alberta has not kept pace with growing loads and new generation connections. In 2009, the Government of Alberta declared several transmission projects as being critical, including three major transmission lines that will be completed between late 2013 and early 2015. A fourth major transmission line, consisting of two lines, is the subject of a competitive procurement process, in which TAMA Transmission, a partnership between TransAlta and MidAmerican Transmission, is participating. The Alberta Electric System Operator ("AESO") announced its selection of a short-list of companies for the first of the two lines, identifying that TAMA Transmission will participate in the next stage of its competitive process for the project. The AESO is expected to start the Request for Proposals ("RFP") process on the second line in 2015. Although the critical transmission projects should address constraints along major paths, a number of regional transmission lines are currently constrained or are forecast to become constrained in the near future as a result of new connections. In January 2014, the AESO published a new long-term transmission plan and has proposed a number of new transmission facilities to address these regional constraints. Until these projects can be completed, there will continue to be transmission constraints in some regions of the province, particularly southern Alberta, central-eastern Alberta, and Fort McMurray.

Ontario

Ontario has procured significant quantities of generation, in particular renewable generation, but procurement has been limited to prevent significant congestion on Ontario's transmission system. Several transmission projects in both southwestern and northeastern Ontario have been developed to increase transmission capability and facilitate the procurement of additional generation. The Independent Electricity System Operator's forecast of constrained generation for the time period from 2013 to 2015 includes minor impacts to generation in southwestern Ontario and significant impacts to generation in northern Ontario. Rapid load growth in the area north of Dryden as well as the potential to develop the mineral-rich area known as the Ring of Fire could require significant transmission expansion. This transmission expansion may be subject to a competitive process.

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 to some extent through change-in-law provisions in our PPAs. 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. 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 ("CCS") project ("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 should provide ongoing value in the assessment of other carbon control strategies. We also are actively and broadly disseminating the knowledge from Project Pioneer to others who may benefit from it.

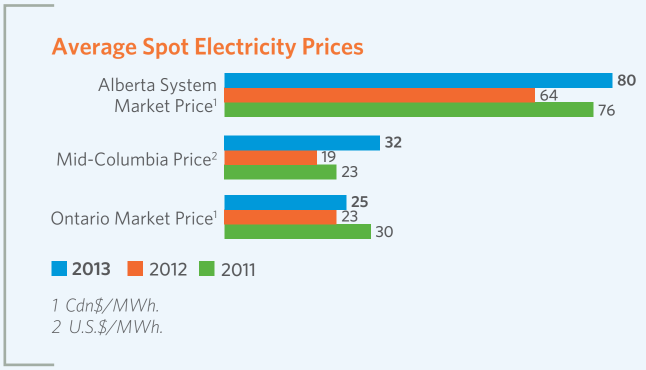
Economic Environment

In 2014, we expect slow to moderate growth in all 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, approximately 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. The average prices of these contracts for 2013 were approximately $60 per megawatt hour ("MWh") in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

Electricity Prices



Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability, 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.

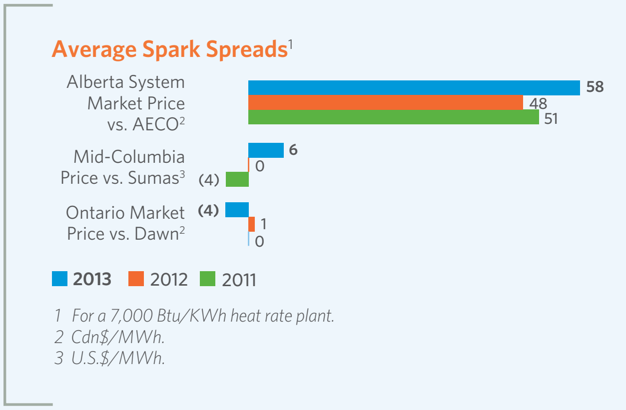
Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, and the other business environment dynamics discussed above. We monitor these trends in prices, and schedule maintenance, where possible, during times of lower prices.

For the year ended Dec. 31, 2013, average spot prices in Alberta increased compared to 2012, primarily due to tighter supply and demand conditions. In the Pacific Northwest, average spot prices increased due to higher natural gas prices and lower hydro generation. Average spot prices in Ontario for the year ended Dec. 31, 2013 increased compared to 2012 due to higher natural gas prices, which was partially offset by an increase in supply as a result of nuclear generating plants returning to service.

In 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation and fewer planned maintenance outages across the market. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle higher than in 2013 due to marginally higher natural gas prices and an outlook for lower hydro generation compared to 2013.

In 2012, average spot prices in all three markets decreased compared to 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.

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 operational results.

For the year ended Dec. 31, 2013, average spark spreads increased in Alberta compared to 2012 due to higher power prices driven by tighter supply and demand conditions. In the Pacific Northwest, average spark spreads increased due to higher power prices driven by lower hydro generation. Average spark spreads in Ontario decreased for the year ended Dec. 31, 2013 compared to 2012 as power prices did not rise as rapidly as natural gas prices, largely due to nuclear generating plants returning to service and increased renewables generation.

In 2012, average spark spreads in Alberta decreased compared to 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.

Strategy

Our goals are to deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share, while striving for a low to moderate risk profile, balancing capital allocation, and maintaining financial strength. Our comparable cash flow growth is driven by optimizing and diversifying our existing assets and further expanding our overall portfolio and operations in Canada, the U.S., and Australia. We are focusing on these geographic areas as our expertise, scale, and diversified fuel mix allows us to create expansion opportunities in our core markets. Our strategy to achieve these goals has the following key elements:

Growth Strategy

Our growth strategy is to continue to diversify our asset base in three core markets with a focus on renewables and natural gas-fired generation. Furthermore, we are focused on ensuring we replace our coal assets that are scheduled to retire in Alberta and the Pacific Northwest.

During 2013, we executed on our strategy through the commencement of commercial operations at our 68 MW New Richmond wind farm and the acquisition of a 144 MW wind farm in Wyoming through one of our wholly owned subsidiaries. In early 2014 we announced the construction of a new natural gas pipeline in Australia. Please refer to the Significant Events section of this MD&A for more information.

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 2013, we continued to see some demand growth in our Alberta market; however, demand in the Pacific Northwest and Ontario remained relatively flat. While we are not immune to lower power prices, the impact of these lower prices is mitigated through our contracting strategy. Currently, approximately 88 per cent of 2014 and approximately 80 per cent of 2015 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 2014 is to increase productivity and achieve overall fleet availability of 88 to 90 per cent. Over the last three years, our average adjusted availability has been 88.7 per cent, which is slightly below our corporate target.

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 2014. We continue to maintain $2.1 billion in committed credit facilities, and as of Dec. 31, 2013, $0.9 billion was available to us. Our investment grade credit rating, available credit facilities, FFO, manageable debt maturity profile, and access to the capital markets 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 2013, we took advantage of favourable capital markets by completing the initial public offering of TransAlta Renewables in August, as well as an offering of $400 million of Canadian medium-term senior notes. Looking forward, we expect continued capital market support for projects that meet our return requirements and risk profile.

Our senior unsecured debt is rated as investment grade, BBB- (stable), Baa3 (stable), and BBB (stable) with Standard and Poor's ("S&P"), Moody's Investors Services, and DBRS, respectively. Our preferred shares are rated P-3 and Pfd-3 with S&P and DBRS, respectively.

Participation in the Dividend Reinvestment and Share Purchase ("DRASP") plan is approximately 30 to 35 per cent.

Disciplined Capital Allocation

We are committed to optimizing the balance between returning capital to shareholders, investing in the base business and growth opportunities, and maintaining a strong financial postion.

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. During 2013, commercial operations began at our 68 MW New Richmond wind farm, and in early 2014 we announced the construction of a new natural gas pipeline in Australia. We also completed the acquisition of a 144 MW wind farm in Wyoming through one of our wholly owned subsidiaries.

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.

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

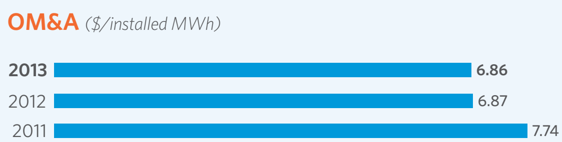
1 Adjusted for economic dispatching at Centralia Thermal.

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 from 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 88.7 per cent, which was slightly below our long-term target of 89 to 90 per cent. If availability is also adjusted for the force majeure outage at Keephills Unit 1, the average adjusted availability is 89.7 per cent, which is within our long-term target. Our availability in 2013, after adjusting for economic dispatching at Centralia Thermal, was 87.8 per cent (2012 – 90.0 per cent).

Availability for the year ended Dec. 31, 2013 decreased compared to 2012, primarily due to higher unplanned outages at the Alberta coal PPA facilities, which was largely driven by the Keephills Unit 1 force majeure outage, partially offset by lower planned outages at the Alberta coal PPA facilities.

In 2012, availability increased compared to 2011, primarily due to lower planned and unplanned outages at Centralia Thermal and lower unplanned outages at the Alberta coal PPA facilities, partially offset by higher planned outages at the Alberta coal PPA facilities.

Operating Costs



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, 2013, OM&A costs per installed MWh were consistent with 2012.

In 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 reducing costs.

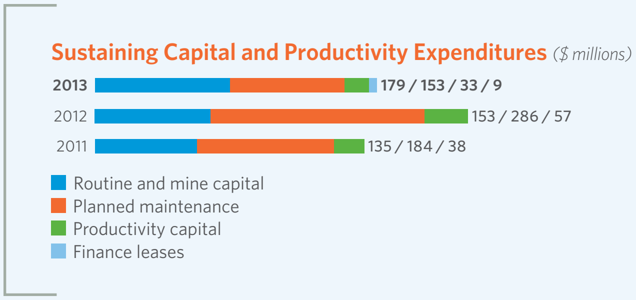
Cash Flow

We focus our base business on delivering strong cash flows. In addition, our goal is to steadily grow comparable EBITDA and cash flows over the long term through the addition of new assets, recognizing that the amount of growth may fluctuate year over year with the amount of our cash flows from our base business.

Year ended Dec. 31	2013	2012	2011
Comparable EBITDA	**1,023**	1,015	1,044
Comparable Earnings Per Share ("EPS")	**0.31**	0.50	1.05
FFO	**729**	788	812
FFO per share	**2.76**	3.35	3.66
Free cash flow	**295**	258	417
Free cash flow per share	**1.12**	1.10	1.88

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 expenditures are comprised of four components: (i) routine and mine capital, (ii) planned maintenance, (iii) productivity capital, and (iv) finance lease.



In 2013, we spent $122 million less on sustaining capital and productivity expenditures compared to 2012, which was made up of $11 million more on routine capital, an increase of $15 million on mine capital, $133 million less on planned maintenance, a decrease of $24 million on productivity, and $9 million more on finance leases. The increase in routine capital was primarily due to the generating rewind at the Keephills facility. Mine capital increased as a result of the purchase of pre-stripping trucks during the year. Planned maintenance decreased, primarily due to fewer planned outages during the year. Productivity expenditures decreased as a result of a reduction in corporate improvement initiatives. The finance leases were for mining equipment that was in use, or committed to, by Prairie Mines and Royalty Ltd. ("PMRL") for mining operations at our Highvale Mine.

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.

Safety

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

Year ended Dec. 31	2013	2012	2011
IFR	**0.93**	0.89	0.89

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.

Year ended Dec. 31	2013	2012	2011
Adjusted cash flow to interest coverage *(times)*[1,2]	**4.0**	4.4	4.4
Adjusted cash flow to debt *(%)*[1,3]	**16.9**	19.0	20.1
Debt to comparable EBITDA *(times)*[4]	**4.2**	4.1	3.8

1 Adjusted for the impacts associated with the California claim in 2013 and the Sundance Units 1 and 2 arbitration in 2012.

2 Adjusted cash flow to interest coverage is calculated as cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest income.

3 Adjusted cash flow to debt is calculated as cash flow from operating activities before changes in working capital divided by average total debt less average cash and cash equivalents.

4 Debt to comparable EBITDA is calculated as long-term debt including current portion less cash and cash equivalents divided by comparable EBITDA.

Adjusted cash flow to interest coverage decreased in 2013 compared to 2012, primarily due to higher interest on debt. Adjusted cash flow to interest coverage in 2012 was comparable to 2011. Our goal is to maintain this ratio in a range of four to five times.

Adjusted cash flow to debt decreased in 2013 compared to 2012, due to higher average debt levels in 2013. Adjusted cash flow to debt decreased in 2012 compared to 2011 due to higher average debt levels in 2012. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

We have elected to present debt to comparable EBITDA in place of the debt to invested capital ratio. We believe that the EBITDA-based metric is more relevant to the users of the financial statements as it is a more current, cash-based metric, rather than the invested capital metric, which uses historical balances. We also believe that the debt to comparable EBITDA ratio is a more meaningful metric that is consistent with the metrics the rating agencies that cover TransAlta use.

Debt to comparable EBITDA as at Dec. 31, 2013 was comparable to 2012. Debt to comparable EBITDA increased as at Dec. 31, 2012 compared to 2011 due to higher average debt levels and lower comparable EBITDA in 2012. Our goal is to maintain this ratio in a range of four to five times.

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 2013, we took several steps to strengthen our financial position and reduce debt, using the approximate $221 million in gross proceeds from the initial public offering of TransAlta Renewables to pay down debt, and utilizing the proceeds from dividends reinvested under the DRASP plan as a continued source of equity. Participation in the DRASP plan is currently at approximately 35 per cent.

We seek to maintain financial flexibility by using multiple sources of capital to finance capital allocation plans effectively, while maintaining a sufficient level of available liquidity to support contracting and trading activities. Further, financial flexibility allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are favourable 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 generate Total Shareholder Returns ("TSR")[1] through a combination of cash flow growth and dividend yield.

The table below shows our historical performance on this measure:

Year ended Dec. 31	**2013**	2012	2011
TSR (%)	**(3.2)**	(22.5)	4.9

We continue to focus on delivering shareholder returns. Improvements in the business will come from investments in productivity, with a focus on improving the Alberta coal business. We continue to be disciplined in our capital allocation process and are actively seeking growth opportunities in the U.S., Western Australia, and Canada, as demonstrated by the acquisition of the Solomon power station in 2012, the commencement of commercial operations at New Richmond, the Wyoming wind farm acquisition in the U.S., and the announcement of the Australian natural gas pipeline project in 2014. We are focused on delivering cash flow to fund the dividends and growth and maintain investment grade credit ratings.

1 *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. For this MD&A, we have further split what is reported as our Generation business segment into the various fuel types to provide additional information to our readers. 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.

Significant Events

Our consolidated financial results include the following significant events:

2013

California Claim

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered us to refund approximately U.S.$47 million for sales we made in the organized markets of the California Power Exchange, the California Independent System Operator, and the California Department of Water Resources during the 2000 – 2001 period. In addition, the California parties have sought additional refunds that to date have been rejected by FERC. We have established a U.S.$47 million provision to cover any potential refunds. Final rulings are not expected in the near future.

For the year ended Dec. 31, 2013, we accrued for a potential settlement of all outstanding disputes with the California parties, which resulted in a pre-tax charge to earnings of approximately U.S.$52 million.

Eastern Canada Ice Storm

In late December 2013, extreme weather conditions impacted our operations in parts of Ontario and Atlantic Canada, causing icing on turbine blades and consequently requiring us to shut down some of the wind turbines. The impact ranged from 7 to 12 days of downtime at each of the affected facilities, a total of 25.6 GWh of lost production, and approximately $3 million in total lost revenues. Operations at all impacted sites have returned to normal.

Acquisition by TransAlta Renewables

On Dec. 20, 2013, we completed the acquisition, through one of our wholly owned subsidiaries, of a 144 MW wind farm in Wyoming for approximately U.S.$102 million from an affiliate of NextEra Energy Resources, LLC. The wind farm is fully operational and contracted under a long-term PPA until 2028 with an investment grade counterparty. An economic interest in the wind farm was acquired by TransAlta Renewables from the Corporation in consideration for a payment equal to the original purchase price of the acquisition. We have extended a U.S.$102 million loan to TransAlta Renewables to fund the acquisition. Terms of the loan require TransAlta Renewables to repay a minimum of U.S.$45 million of the loan over the first 36 months with free cash flow from operations, and the balance on maturity on Dec. 31, 2018, through a long-term debt refinancing that is expected to be completed in conjunction with other financing needs of TransAlta Renewables.

The acquisition is expected to be accretive to cash flow per share for both the Corporation and TransAlta Renewables.

Senior Notes Offering

On Nov. 25, 2013, we completed an offering of $400 million medium-term senior notes that carry a coupon rate of 5.0 per cent, payable semi-annually, at an issue price equal to 99.516 per cent of the principal amount of the notes. The net proceeds from the offering were used to repay indebtedness, finance our long-term investment plan and growth projects, and for general corporate purposes.

Western Australia Contract Extension

On Oct. 30, 2013, we announced a long-term contract extension to supply power to the BHP Billiton Nickel West operations in Western Australia from our Southern Cross Energy facilities ("Southern Cross"). The extension is effective immediately and replaces the previous contract, which was set to expire at the beginning of 2014.

Operating since 1996, Southern Cross has a total installed capacity of 245 MW from the Kambalda, Mt. Keith, Leinster, and Kalgoorlie power stations.

Salt River Project

On Sept. 17, 2013, we announced that CalEnergy, a joint venture with MidAmerican Energy Holdings Company ("MidAmerican"), executed a 50 MW long-term contract for renewable geothermal power with Salt River Project, an Arizona utility, which runs from 2016 to 2039.

Ontario Power Authority

On Aug. 30, 2013, we announced the execution of a new agreement for a 20-year power supply term with the OPA, for our Ottawa gas facility, which is effective January 2014.

Under the new deal the plant will become dispatchable. This will assist in reducing the incidents of surplus baseload generation in the market, while maintaining the ability of the system to reliably produce energy when it is needed.

This new contract will benefit our shareholders by providing long-term stable earnings from this facility and will benefit ratepayers of Ontario by securing attractively priced capacity from this existing facility, reducing the need for new capacity to be built in the future and allowing hospitals in the area to continue to be served with the steam they need for heat and other energy processes, in an environmentally friendly manner.

TransAlta Renewables

On May 28, 2013, we formed a new subsidiary, TransAlta Renewables, to provide investors with the opportunity to invest directly in a highly contracted portfolio of power generation facilities. We retain control over TransAlta Renewables, and therefore we consolidate TransAlta Renewables. As a result, any loans outstanding or transactions between the Corporation and TransAlta Renewables are eliminated on consolidation in our financial statements.

Transfer of Generating Assets

On Aug. 9, 2013, we transferred 28 indirectly owned wind and hydroelectric generating assets to TransAlta Renewables through the sale of all the issued and outstanding shares of two subsidiaries: Canadian Hydro Developers, Inc. ("CHD") and Western Sustainable Power Inc. As consideration for the transfer, we received: i) 66.7 million common shares of TransAlta Renewables valued at $10 per share for total share consideration of $667 million; ii) a Closing Note receivable in the amount of $187 million; iii) a Short Term Note receivable in the amount of $250 million; iv) an Acquisition Note receivable in the amount of $30 million; and v) an Amortizing Loan receivable in the amount of $200 million.

Initial Public Offering of Common Shares

On July 31, 2013, TransAlta Renewables filed a final prospectus to qualify the distribution of 20.0 million of its common shares, to be issued pursuant to the terms of an underwriting agreement at a price of $10.00 per common share (the "Offering"). TransAlta Renewables granted to the underwriters an option (the "Over-Allotment Option"), exercisable in whole or in part for a period of 30 days following Closing, to purchase, at the Offering price, up to an additional 3.0 million common shares (representing 15 per cent of the common shares offered under the prospectus).

On Aug. 29, 2013, TransAlta Renewables completed the Offering and issued 20.0 million common shares for gross proceeds of $200 million. The net proceeds of the Offering were used by TransAlta Renewables to repay the $187 million Closing Note issued to the Corporation. On Aug. 29, 2013, the underwriters exercised their Over-Allotment Option in part to purchase an additional 2.1 million common shares at the Offering price of $10.00 per common share for gross proceeds of $21 million. TransAlta Renewables used the net proceeds received from the partial exercise of the Over-Allotment Option to repay a portion of the amount outstanding under the Acquisition Note issued to TransAlta. The remaining principal amount of $9 million outstanding under the Acquisition Note after such payment was converted into 0.9 million common shares of TransAlta Renewables on the basis of one common share for each $10.00 owing to the Corporation under the Acquisition Note. After completion of the transactions, we own 92.6 million common shares of TransAlta Renewables, representing an 80.7 per cent ownership interest. In total, we received $207 million in cash consideration net of commissions and expenses.

Effective Aug. 9, 2013, the net earnings and total comprehensive income (loss) attributable to the 19.3 per cent divested interest are reflected in net earnings (loss) attributable to non-controlling interests and total comprehensive income (loss) attributable to non-controlling interests, respectively, on the Consolidated Statements of Earnings (Loss) and on the Consolidated Statements of Comprehensive Income (Loss), respectively. The excess of consideration received over the net book value of our divested interest was $4 million and was recorded in retained earnings (deficit). As at Dec. 31, 2013, the net assets attributable to the 19.3 per cent divested interest are reflected in equity attributable to non-controlling interests in the Consolidated Statements of Financial Position.

Update on Hydro Facilities Due to Southern Alberta Flooding

Following extremely high rainfall and flooding during the second quarter in southern Alberta, we continue to safely and efficiently resolve operational challenges related to our hydro systems. Three of the hydro facilities we operate in Alberta in the Bow River Basin continue to be impacted by the flooding events and are currently being repaired. We have assessed any financial impact and continue to believe that we have sufficient insurance coverage for this damage, subject to a $5 million deductible.

City of Riverside

On June 18, 2013, we announced that CalEnergy had executed an 86 MW long-term contract for renewable geothermal power with the City of Riverside which runs from 2016 to 2039. CalEnergy will purchase the power from CE Generation LLC's ("CE Gen") portfolio of geothermal generating facilities in California's Imperial Valley.

Sundance Units 1 and 2 Return to Service

In December 2010, Units 1 and 2 of our Sundance facility were shut down due to conditions observed in the boilers at both units. On July 20, 2012, an arbitration panel concluded that Unit 1 and Unit 2 were not economically destroyed under the terms of the PPA and we were required to restore the units to service. For the year ended Dec. 31, 2012, the pre-tax income statement impact of the ruling that has been recorded under the caption "Sundance Units 1 and 2 return to service" in the Consolidated Statements of Earnings (Loss) was $254 million.

The cost to repair Sundance Units 1 and 2 was approximately $215 million. The total estimated spend increased by $25 million due to additional scope of work for balance of plant systems and equipment as well as higher labour costs due to an increase in labour rates. This work was performed concurrently with the boiler repairs to prevent the need for a later outage for this work. During 2013, $25 million of components were retired as a result of the work completed on the units to return them to service. Sundance Unit 1 returned to service on Sept. 2, 2013 and Unit 2 returned to service on Oct. 4, 2013. We have issued notices to the buyers regarding the cessation of the force majeure period for the two units.

Premium Dividend™ Program

On May 8, 2013, we announced that as a result of the current low share price environment, we would suspend the Premium Dividend™ component of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "Plan") following the payment of the quarterly dividend on July 1, 2013. Our Dividend Reinvestment and Optional Common Share Purchase Plan, components of the Plan remain effective in accordance with their current terms.

Keephills Unit 1

On March 5, 2013, an outage occurred at Unit 1 of our Keephills facility due to a stator winding failure found in the generator. Upon completion of the initial repair work, further condition testing and analysis identified greater winding degradation requiring a full rewind of the generator stator. In response to the event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. In the event of a force majeure, we are entitled to continue to receive our PPA capacity payment and are protected under the terms of the PPA from having to pay availability penalties. As a result, we do not expect the outage to have a material financial impact on the Corporation. The Unit was returned to service on Oct. 6, 2013. Arbitration on the matter began during the third quarter.

New Richmond

On March 13, 2013, our 68 MW New Richmond wind farm began commercial operations. The total cost of the project was approximately $212 million. During 2013, we received a $13 million reimbursement for costs of the terminal station.

SunHills Mining Limited Partnership

Effective Jan. 17, 2013, we assumed, through our wholly owned SunHills Mining Limited Partnership ("SunHills"), operations and management control of the Highvale Mine from PMRL. PMRL employees working at the Highvale Mine were offered employment by SunHills, which agreed to assume responsibility for certain pension plan and pension funding obligations, that we previously funded through the payments made under the PMRL mining contracts. As a result, a pre-tax loss of $29 million was recognized during the first quarter, along with the corresponding liabilities.

We also entered into finance leases for mining equipment that was in use, or committed to, by PMRL for mining operations. As a result, $33 million in mining equipment has been capitalized to PP&E and the related finance lease obligations recognized during 2013. At the end of the lease terms, we are eligible to purchase the assets for a nominal amount.

Change in Estimates – Useful Lives

During 2013, management completed a review of the estimated useful lives of our hydro assets, having regard for, among other things, our economic life cycle maintenance program and the existing condition of the assets. As a result, depreciation was reduced by $5 million for the year ended Dec. 31, 2013 and is expected to be reduced by $5 million annually thereafter.

Centralia Coal Inventory Writedown

During the year ended Dec. 31, 2013, we recognized a pre-tax writedown of $22 million related to the coal inventory at our Centralia plant to write the inventory down to its net realizable value.

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 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 an 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 a 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 Metals Group Ltd. ("Fortescue") of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility will be commissioned during 2014. 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. was 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 a 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 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 June 25, 2013, regulatory approval was confirmed by the WUTC and as of July 5, 2013, the contract was in effect in accordance with the WUTC's terms and conditions.

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.

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 12 MW, bringing the maximum capability of these units to 395 MW each. The total costs of the projects were approximately $51 million.

Project Pioneer

On April 26, 2012, Project Pioneer's industry partners announced they would not proceed with the joint 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 was not material for our 2012 results.

Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase 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 of Directors 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 operation 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.

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, and 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.

Subsequent Events

CE Gen, Blackrock Development Project, and Wailuku Holding Company, LLC

On Feb. 20, 2014, we announced an agreement to sell our 50 per cent ownership of CE Gen, the Blackrock development project ("Blackrock"), and Wailuku Holding Company, LLC ("Wailuku") to MidAmerican Renewables for proceeds of U.S.$193.5 million. MidAmerican Renewables holds the other 50 per cent interest in CE Gen, Blackrock, and Wailuku.

Dividend

On Feb. 20, 2014, we announced the resizing of our dividend to a quarterly dividend of $0.18 per common share (or $0.72 per common share on an annualized basis) to align with our growth and financial objectives.

Sundance Unit 6 Agreement

On Feb. 19, 2014, we reached an agreement with the PPA Buyer related to the dispute on Sundance Unit 6. We do not expect any material impact to the financial statements as a result of the agreement.

Keephills Unit 2

On Jan. 31, 2014, an outage commenced at Unit 2 of our Keephills facility to perform a rewind of the generator stator as a result of the generator event in 2013 at Keephills Unit 1. We gave notice of a HILP event and claimed force majeure relief under the PPA.

Fort McMurray Transmission Project

On Jan. 17, 2014, we announced that our strategic partnership with MidAmerican Transmission, TAMA Transmission, which was formed on May 9, 2013, successfully qualified to participate as a proponent in the Fort McMurray West 500 kilovolt Transmission Project. The AESO announced its selection of a short-list of companies, identifying that TAMA Transmission will participate in the next stage of its competitive process for the project.

Australia Natural Gas Pipeline

On Jan. 15, 2014, we announced that, through a wholly owned subsidiary, an unincorporated joint venture named Fortescue River Gas Pipeline was formed, of which we have a 43 per cent interest. The first project of the new joint venture will be to build, own, and operate a $178 million natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station.

Discussion of Segmented Results

We have three business segments: Generation, Energy Trading, and Corporate.

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. Starting in 2013, electricity sales generated by our Commercial and Industrial group are assumed to be sourced from TransAlta's production and have been included in the Generation Segment on a net basis.**

For more information on the strategic partnerships that we have entered into with MidAmerican and MidAmerican Transmission, please refer to the Significant Events section of this MD&A. MidAmerican also owns a 50 per cent interest in CE Gen and Wailuku. We are also involved in various joint arrangements with Canadian Power Holdings Inc. ("Canadian Power"), Capital Power, ENMAX Corporation ("ENMAX"), Nexen Inc. ("Nexen"), and Brookfield Asset Management Inc. ("Brookfield"). Canadian Power owns the minority interest in TA Cogen. The Capital Power joint arrangement 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 interests in the CE Gen, Wailuku, TAMA Transmission, and CalEnergy 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 international geographical regions. Although these assets no longer contribute to the operating income for accounting purposes, it is management's view that these facilities still form part of our operational results. Refer to the Equity Investments 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.

Coal: TransAlta owns and operates coal-fired facilities and related mining operations in Canada and the U.S. Coal revenues and overall profitability are derived from the availability and production of electricity.

Canadian Coal

During 2013, we completed the restoration of Sundance Units 1 and 2. For further information please refer to the Significant Events section of this MD&A.

Year ended Dec. 31	2013	2012	2011
Production *(GWh)*	**21,568**	20,265	21,475
Installed capacity *(MW)*	**3,576**	3,012	2,985
Revenues	**916**	913	760
Fuel and purchased power	**451**	383	324
Comparable gross margin[1]	**465**	530	436
Operations, maintenance, and administration	**201**	195	202
Taxes, other than income taxes	**11**	10	9
Intersegment cost allocation	**4**	3	–
Gain on sale of property, plant, and equipment	**(2)**	(10)	(8)
Mine depreciation	**(58)**	(41)	(40)
Comparable EBITDA[1]	**309**	373	273
Depreciation and amortization	**292**	268	220
Other[2]	**–**	(20)	(40)
Comparable operating income[1]	**17**	125	93
Sustaining expenditures:			
Routine capital	**69**	59	33
Mining equipment and land purchases	**65**	38	20
Finance leases	**9**	–	–
Planned major maintenance[3]	**94**	219	68
Total sustaining expenditures	**237**	316	121

2013

Production for the year ended Dec. 31, 2013 increased 1,303 GWh compared to 2012 due to Sundance Units 1 and 2 returning to service, lower planned outages at the Alberta coal PPA facilities, lower market curtailments, and higher PPA customer demand, partially offset by higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage.

For the year ended Dec. 31, 2013, comparable EBITDA decreased by $64 million compared to 2012 due to lower realized prices, higher penalties, higher coal costs, and higher unplanned outages at the Alberta coal PPA facilities, partially offset by lower planned outages at the Alberta coal PPA facilities and lower market curtailments. Coal costs increased as a result of an increased asset base from the mine transition and the normal advancement of the mine.

Depreciation and amortization for the year ended Dec. 31, 2013 increased by $24 million compared to 2012 due to an increased asset base and an increase in mine depreciation, partially offset by a decrease in asset retirements and the effect of the change of the economic useful lives of certain plants during 2012.

For the year ended Dec. 31, 2013, the decrease in sustaining capital expenditures compared to 2012 is mainly due to the lower number of planned outages, offset by higher mining equipment purchases.

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.*

2 *Impacts to revenue associated with Sundance Units 1 and 2 to provide period over period comparability.*

3 *Consists of three planned outages in 2013, six planned outages in 2012, and four planned outages in 2011.*

2012

Production for the year ended Dec. 31, 2012 decreased 1,210 GWh compared to 2011 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 and lower unplanned outages at the Alberta coal PPA facilities.

For the year ended Dec. 31, 2012, comparable EBITDA increased by $100 million compared to 2011 due to favourable pricing, net of unrealized mark-to-market movements and provisions, the commencement of commercial operations at Keephills Unit 3, and lower unplanned outages at the Alberta coal PPA facilities, partially offset by higher planned outages at the Alberta coal PPA facilities and unfavourable coal pricing.

Depreciation and amortization for the year ended Dec. 31, 2012 increased by $48 million compared to 2011 due to an increased asset base, largely due to the commencement of commercial operations at Keephills Unit 3, and an increase in asset retirements, partially offset by a change in the economic lives of certain plants. Please refer to the Significant Events section of this MD&A for more information.

For the year ended Dec. 31, 2012, the increase in sustaining capital expenditures compared to 2011 was due to a high number of planned outages at Keephills Units 1 and 2 and Sundance Units 3 and 5.

U.S. Coal

Year ended Dec. 31	**2013**	2012	2011
Production *(GWh)*	**6,711**	3,736	5,135
Installed capacity *(MW)*	**1,340**	1,340	1,340
Revenues	**346**	368	534
Fuel and purchased power	**205**	150	262
Comparable gross margin	**141**	218	272
Operations, maintenance, and administration	**43**	39	47
Inventory writedown	**22**	19	–
Taxes, other than income taxes	**4**	6	6
Intersegment cost allocation	**6**	7	8
Gain on sale of property, plant, and equipment	**–**	(1)	–
Comparable EBITDA	**66**	148	211
Depreciation and amortization	**56**	66	80
Comparable operating income	**10**	82	131
Sustaining expenditures:			
Routine capital	**6**	10	18
Planned major maintenance	**10**	22	45
Total sustaining expenditures	**16**	32	63

2013

Production for the year ended Dec. 31, 2013 increased 2,975 GWh compared to 2012 due to lower economic dispatching at Centralia Thermal, driven by improving market conditions, partially offset by higher planned outages at Centralia Thermal.

For the year ended Dec. 31, 2013, comparable EBITDA decreased by $82 million compared to 2012 due to contracts expiring and lower spot prices, partially offset by favourable coal pricing.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $10 million compared to 2012 due to the impact of a lower asset base as a result of asset impairments.

For the year ended Dec. 31, 2013, the decrease in sustaining capital expenditures compared to 2012 is mainly due to the lower expenditures on planned outages.

2012

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

Production for the year ended Dec. 31, 2012 decreased 1,399 GWh compared to 2011 due to higher economic dispatching at Centralia Thermal, partially offset by lower planned and unplanned outages at Centralia Thermal.

For the year ended Dec. 31, 2012, comparable EBITDA decreased $63 million compared to 2011 due to lower pricing, including margins on purchased power, partially offset by reductions in OM&A due to lower routine maintenance and lower compensation costs as a result of productivity initiatives and a continued focus on costs.

Depreciation and amortization for the year ended Dec. 31, 2012 decreased $14 million compared to 2011 due to a lower asset base as a result of asset impairments.

For the year ended Dec. 31, 2012, the decrease in sustaining capital expenditures compared to 2011 was due to the lower expenditures on planned outages.

Gas: TransAlta owns and operates natural gas-fired facilities in Canada and Australia. Gas revenues and overall profitability are derived from the availability and production of electricity and steam.

Year ended Dec. 31	**2013**	2012	2011
Production *(GWh)*[1]	**7,854**	8,230	7,936
Installed capacity *(MW)*[1]	**1,567**	1,567	1,567
Revenues	**636**	607	647
Fuel and purchased power	**252**	226	288
Comparable gross margin	**384**	381	359
Operations, maintenance, and administration	**100**	86	91
Taxes, other than income taxes	**3**	4	4
Finance lease income	**(47)**	(19)	(11)
Intersegment cost allocation	**2**	1	-
Gain on sale of property, plant, and equipment	**-**	(3)	-
Insurance recovery	**(1)**	-	-
Comparable EBITDA	**327**	312	275
Depreciation and amortization	**107**	109	109
Other	**1**	3	3
Comparable operating income	**219**	200	163
Sustaining expenditures:			
Routine capital	**17**	13	12
Planned major maintenance	**41**	36	57
Total sustaining expenditures	**58**	49	69

2013

Production for the year ended Dec. 31, 2013 decreased 376 GWh compared to 2012 due to higher contract and market curtailments at our Ottawa and Sarnia facilities, partially offset by lower unplanned outages at our Sarnia facility.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $15 million compared to 2012 due to a full year of income from the Solomon power station that was acquired in August 2012, partially offset by higher OM&A costs resulting from higher routine maintenance.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $2 million compared to 2012 due to a decrease in asset retirements and favourable changes in foreign exchange rates.

1 *Includes production and net ownership capacity for Fort Saskatchewan, a natural gas-fired facility that has been accounted for as a finance lease.*

2012

Production for the year ended Dec. 31, 2012 increased 294 GWh compared to 2011 due to favourable market conditions at our facilities.

For the year ended Dec. 31, 2012, comparable EBITDA increased by $37 million compared to 2011 due to favourable contracted gas input costs, an increase in finance lease income from the start of our PPA at our Solomon power station in October 2012, and a decrease in OM&A due to productivity initiatives and a continued focus on costs.

Depreciation and amortization for the year ended Dec. 31, 2012 was comparable to 2011.

Renewables: **TransAlta owns and operates hydro and wind facilities in Canada and the U.S. Renewable revenues and overall profitability are derived from the availability of water and wind resources and the production of electricity, as well as ancillary services such as system support.**

Wind

During 2013, we began commercial operations at New Richmond, a 68 MW wind farm in Québec. We also completed the acquisition of a 144 MW wind farm in Wyoming through one of our wholly owned subsidiaries. For further information please refer to the Significant Events section of this MD&A.

Year ended Dec. 31	**2013**	2012	2011
Production *(GWh)*	**2,709**	2,583	2,802
Installed capacity *(MW)*	**1,077**	1,061	1,061
Revenues	**237**	207	231
Fuel and purchased power	**13**	12	14
Comparable gross margin	**224**	195	217
Operations, maintenance, and administration	**38**	38	48
Taxes, other than income taxes	**5**	5	6
Intersegment cost allocation	**1**	1	–
Comparable EBITDA	**180**	151	163
Depreciation and amortization	**79**	72	72
Comparable operating income	**101**	79	91
Sustaining expenditures:			
Routine capital	**3**	2	8
Planned major maintenance	**6**	2	(1)
Total sustaining expenditures	**9**	4	7

2013

Production for the year ended Dec. 31, 2013 increased 126 GWh compared to 2012 due to the commencement of commercial operations at New Richmond.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $29 million compared to 2012 due to the commencement of commercial operations at New Richmond and higher Alberta merchant prices.

Depreciation and amortization for the year ended Dec. 31, 2013 increased by $7 million compared to 2012 due to the commencement of operations at New Richmond.

2012

Production for the year ended Dec. 31, 2012 decreased 219 GWh compared to 2011 due to lower wind volumes and the sale of the Grande Prairie biomass facility in 2011.

For the year ended Dec. 31, 2012, comparable EBITDA decreased by $12 million compared to 2011 due to unfavourable prices, lower wind volumes, and the sale of the Grande Prairie biomass facility in 2011, partially offset by lower OM&A due to the sale of the Grande Prairie biomass facility in 2011 and lower compensation costs as a result of productivity initiatives and a continued focus on costs.

Depreciation and amortization for the year ended Dec. 31, 2012 was comparable to 2011.

Hydro

Year ended Dec. 31	**2013**	2012	2011
Production *(GWh)*	**2,085**	2,356	2,044
Installed capacity *(MW)*	**893**	913	913
Revenues	**181**	164	142
Fuel and purchased power	**5**	7	7
Comparable gross margin	**176**	157	135
Operations, maintenance, and administration	**31**	27	30
Taxes, other than income taxes	**3**	2	2
Intersegment cost allocation	**1**	1	–
Insurance recovery	**(6)**	–	–
Gain on sale of property, plant, and equipment	**–**	–	(2)
Comparable EBITDA	**147**	127	105
Depreciation and amortization	**25**	29	23
Comparable operating income	**122**	98	82
Sustaining expenditures:			
Routine capital	**9**	7	17
Planned major maintenance	**5**	7	15
Total sustaining expenditures	**14**	14	32

2013

Production for the year ended Dec. 31, 2013 decreased 271 GWh compared to 2012 due to lower water resources.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $20 million compared to 2012 due to favourable prices, partially offset by lower water resources.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $4 million compared to 2012 due to a change in the useful lives of the hydro assets during 2013.

2012

Production for the year ended Dec. 31, 2012 increased 312 GWh compared to 2011 due to higher water resources.

For the year ended Dec. 31, 2012, comparable EBITDA increased $22 million compared to 2011 due to higher water resource volumes, partially offset by unfavourable prices.

Depreciation and amortization for the year ended Dec. 31, 2012 increased by $6 million compared to 2011 due to an increased asset base and an increase in asset retirements.

Asset Impairment Charges and Reversals

Renewables

During 2013, we recognized a total pre-tax impairment charge of $4 million related to three contracted hydro assets within the renewables fleet. The assets were impaired primarily due to an increase in future capital and operating expenses that resulted from the completion of condition assessments. The annual impairment assessments are based on estimates of fair value less costs to sell derived from long range forecasts. The impairment losses are included in the Generation Segment.

Alberta Merchant

As part of the annual impairment review and assessment process in 2013, it was determined that our Alberta plants with significant merchant capacity should be considered one cash-generating unit (the "Alberta Merchant CGU"). Previously, each plant was assessed for impairment individually. The reasons for this change include consideration of the Final Regulations published by the Canadian federal government in September 2012 governing GHG emissions and the 50-year total life for Canadian coal-fired power plants; and the refinement of our risk management approach and practices regarding our Alberta wholesale market price exposure. The Final Regulations confirmed additional operating time and increased flexibility for our Alberta coal plants and led, in part, to a broadening of our view on the management of our Alberta wholesale market price exposure. While no impairment losses were recognized in 2013 for the Alberta Merchant CGU, total pre-tax impairment losses of $23 million that were recognized previously on renewables plants that now form part of the Alberta Merchant CGU were reversed. The Alberta Merchant CGU's recoverable amount was based on an estimate of fair value less costs to sell using a discounted cash flow methodology, based on our long range forecasts and prices evidenced in the marketplace.

The pre-tax reversal is recognized in the Generation Segment.

Centralia Thermal

The Bill and a Memorandum of Agreement ("MoA") that was signed on Dec. 23, 2011 provided a framework for the orderly transition from coal-fired energy produced at Centralia Thermal and the shutdown of the units in 2020 and 2025. On July 25, 2012, we announced that we entered into a long-term power agreement to provide electricity from the Centralia Thermal plant to PSE from December 2014 until the facility is fully retired in 2025. As a result of these agreements, we recognized a pre-tax impairment charge of $347 million included in the Generation Segment during the year ended Dec. 31, 2012. The impairment assessment was based on whether the carrying amount of the Centralia Thermal plant was recoverable based on an estimate of fair value less costs to sell.

In 2013 and 2012, $28 million and $169 million, respectively, of deferred income tax assets were written off related to the tax benefits of losses associated with our U.S. operations. We wrote these assets off as it was no longer considered probable that sufficient taxable income would be available from our existing U.S. operations to utilize the underlying tax losses. An increase in future U.S. income will allow us to write up our deferred income tax assets in future periods.

Reversals

Impairment charges can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants improve.

Equity Investments

Our investments in joint ventures are accounted for using the equity method and consist of our investments in CE Gen, Wailuku, TAMA Transmission, and CalEnergy.

Our interests in the CE Gen and Wailuku joint ventures are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 852 MW of gross generating capacity (396 MW net ownership interest). The table below summarizes key operational information adjusted to reflect our interest in these investments:

Year ended Dec. 31	**2013**	2012	2011
Availability *(%)*	**91.2**	94.2	94.9
Production *(GWh)*:			
Gas	**385**	380	308
Renewables	**1,170**	1,200	1,312
Total production	**1,555**	1,580	1,620

2013

For the year ended Dec. 31, 2013, availability decreased compared to 2012 due to higher planned and unplanned outages.

For the year ended Dec. 31, 2013, production decreased by 25 GWh compared to 2012 due to higher planned and unplanned outages, partially offset by an increase in customer demand.

Equity loss for the year ended Dec. 31, 2013 was $10 million compared to $15 million for 2012. The reduction of the loss is primarily due to favourable pricing and favourable changes in foreign exchange rates, partially offset by higher planned and unplanned outages.

2012

For the year ended Dec. 31, 2012, availability decreased compared to 2011 due to higher unplanned outages.

For the year ended Dec. 31, 2012, production decreased by 40 GWh compared to 2011 due to higher unplanned outages and lower customer demand.

For the year ended Dec. 31, 2012, equity losses from CE Gen and Wailuku 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.

Since 2001, a significant portion of the output from the CE Gen plants has been subject to 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.

On Sept. 17, 2013, we announced that CalEnergy, a joint venture with MidAmerican, executed a 50 MW long-term contract for renewable geothermal power with Salt River Project, an Arizona utility, which runs from 2016 to 2039.

On June 18, 2013, we also announced that CalEnergy had executed an 86 MW long-term contract for renewable geothermal power with the City of Riverside that runs from 2016 to 2039. CalEnergy will purchase the power from CE Gen's portfolio of geothermal generating facilities in California's Imperial Valley.

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 use 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 the Generation Segment.

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

Year ended Dec. 31	2013	2012	2011
Revenues	**79**	3	137
Fuel and purchased power	**-**	-	-
Comparable gross margin	**79**	3	137
Operations, maintenance, and administration	**32**	29	44
Intersegment cost allocation	**(14)**	(13)	(8)
Comparable EBITDA	**61**	(13)	101
Depreciation and amortization	**1**	-	1
Comparable operating income (loss)	**60**	(13)	100

2013

For the year ended Dec. 31, 2013, Energy Trading comparable EBITDA increased by $74 million compared to 2012 due to strong trading performance across all markets and prudent management of risk. The increase is attributable to successful trading strategies involving regional power demand and price differentials across all markets.

2012

For the year ended Dec. 31, 2012, Energy Trading comparable EBITDA decreased by $114 million compared to 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, partially offset by a decrease in OM&A due to decreased compensation costs as a result of lower earnings.

For the year ended Dec. 31, 2012, the intersegment cost allocation increased compared to 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, procurement, 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	2013	2012	2011
Operations, maintenance, and administration	66	82	84
Taxes, other than income taxes	1	1	–
Comparable EBITDA	(67)	(83)	(84)
Depreciation and amortization	23	20	21
Comparable operating loss	(90)	(103)	(105)
Sustaining expenditures:			
Routine capital	22	24	27
Total sustaining expenditures	22	24	27

2013
For the year ended Dec. 31, 2013, OM&A expense decreased by $16 million compared to 2012 primarily due to lower compensation costs as a result of restructuring in the fourth quarter of 2012 and a continued focus on managing costs, partially offset by a decrease as a result of the way in which certain overhead cost allocations are made within the organization. These changes in methodologies primarily arose as a result of our 2012 realignment of resources and more clear focus between base operations and growth.

2012
For the year ended Dec. 31, 2012, OM&A costs were comparable to 2011.

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2013	2012	2011
Interest on debt	240	227	228
Interest income	–	(2)	–
Capitalized interest	(2)	(4)	(31)
Ineffectiveness on hedges	–	4	(1)
Interest expense	238	225	196
Accretion of provisions	18	17	19
Net interest expense	256	242	215

For the year ended Dec. 31, 2013, net interest expense increased compared to 2012, primarily due to higher debt levels, unfavourable changes in foreign exchange rates, and higher interest rates, partially offset by lower ineffectiveness on hedges.

In 2012, net interest expense increased compared to 2011, primarily due to lower capitalized interest.

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 enacted.

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

Year ended Dec. 31	2013	2012	2011
Earnings (loss) before income taxes	**(12)**	(445)	449
Income attributable to non-controlling interests	**(29)**	(37)	(38)
Equity (income) loss	**10**	15	(14)
Impacts associated with certain de-designated and ineffective hedges	**103**	72	(127)
Asset impairment charges (reversals)	**(18)**	324	17
Restructuring provision	**(3)**	13	–
Gain on sale of assets	**(12)**	(3)	(16)
Sundance Units 1 and 2 return to service	**25**	254	–
(Gain on sale of) reserve on collateral	**–**	(15)	18
Loss on assumption of pension obligations	**29**	–	–
Insurance recovery	**(1)**	–	–
California claim	**56**	–	–
Other non-comparable items	**7**	3	10
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**155**	181	299
Income tax expense (recovery)	**(8)**	102	106
Income tax (expense) recovery related to impacts associated with certain de-designated and ineffective hedges	**36**	25	(46)
Income tax (expense) recovery related to asset impairment charges	**(5)**	(5)	4
Income tax (expense) recovery related to restructuring provision	**(1)**	3	–
Income tax expense related to gain on sale of assets	**(2)**	(1)	(4)
Income tax recovery related to Sundance Units 1 and 2 return to service	**6**	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	**(28)**	(169)	–
Income tax recovery related to the resolution of certain outstanding tax matters	**–**	9	–
Income tax (expense) recovery related to changes in corporate income tax rates	**5**	(8)	–
Income tax recovery related to loss on assumption of pension obligations	**7**	–	–
Income tax recovery related to California claim	**14**	–	–
Reclassification of Part VI.1 tax	**–**	–	(2)
Income tax recovery related to other non-comparable items	**2**	1	3
Income tax expense excluding non-comparable items	**26**	18	66
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items *(%)*	**17**	10	22

For the year ended Dec. 31, 2013, the income tax expense excluding non-comparable items increased compared to 2012 due to the positive resolution of certain tax contingency matters in the prior period and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

In 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.

For the year ended Dec. 31, 2013, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items increased compared to 2012 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 due to the positive resolution of certain tax contingency matters in the prior period.

In 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.

Non-Controlling Interests

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural gas-fired facilities and one coal-fired generating facility with a total gross generating capacity of 705 MW. Canadian Power owns the minority interest in TA Cogen. Natural Forces Technologies, Inc. owns a 17 per cent interest in our Kent Hills facility, which operates 150 MW of wind assets. Public shareholders own a 19.3 per cent interest in TransAlta Renewables, which operates 1,232 MW of renewable assets. Since we own a controlling interest in TA Cogen, Kent Hills, and TransAlta Renewables, 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, Kent Hills, and TransAlta Renewables that we do not own. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen, Kent Hills, and TransAlta Renewables is shown in the financing section as distributions paid to subsidiaries' non-controlling interests.

Earnings attributable to non-controlling interests for the year ended Dec. 31, 2013 decreased $8 million compared to 2012, due to lower earnings at TA Cogen.

In 2012, earnings attributable to non-controlling interests were comparable to 2011.

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 years ended Dec. 31, 2013, 2012, and 2011. 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.

Presenting earnings on a comparable basis, comparable gross margin, comparable operating income, and comparable 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 the 2012 coal inventory writedown, as the recognition of the writedown is related to the hedges that were de-designated or deemed ineffective during prior periods.

Other adjustments to earnings, such as those included in the earnings on a comparable basis calculation, 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.

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.

Comparable operating income and EBITDA 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 and EBITDA of these facilities.

Year ended Dec. 31	2013			2012 (restated)*		
	Reported	Comparable adjustments	Comparable total	Reported	Comparable adjustments	Comparable total
Revenues	2,292	103[1]	2,395	2,210	52[11]	2,262
Fuel and purchased power	926	–	926	753	25[12]	778
Gross margin	1,366	103	1,469	1,457	27	1,484
Operations, maintenance, and administration	516	(5)[2]	511	499	(3)[13]	496
Inventory writedown	22	–	22	44	(25)[12]	19
Taxes, other than income taxes	27	–	27	28	–	28
Finance lease income	(46)	(1)[3]	(47)	(16)	(3)[3]	(19)
Insurance recovery	–	(7)[4]	(7)	–	–	–
Gain on sale of property, plant, and equipment	–	(2)[5]	(2)	–	(14)[5]	(14)
Mine depreciation	–	(58)[6]	(58)	–	(41)[6]	(41)
Earnings before interest, taxes, depreciation, and amortization	847	176	1,023	902	113	1,015
Depreciation and amortization	525	58[7]	583	509	55[14]	564
Asset impairment charges	(18)	18[8]	–	324	(324)[8]	–
Restructuring provision	(3)	3[8]	–	13	(13)[8]	–
Other	–	1[3]	1	–	(17)[15]	(17)
Operating income	343	96	439	56	412	468
Equity loss	(10)	–	(10)	(15)	–	(15)
California claim	(56)	56[8]	–	–	–	–
Sundance Units 1 and 2 return to service	(25)	25[8]	–	(254)	254[8]	–
Gain on sale of assets	12	(12)[8]	–	3	(3)[8]	–
Other income	–	–	–	1	–	1
Foreign exchange gain (loss)	1	–	1	(9)	–	(9)
Loss on assumption of pension obligations	(29)	29[8]	–	–	–	–
Gain on sale of collateral	–	–	–	15	(15)[8]	–
Insurance recovery	8	(8)[9]	–	–	–	–
Earnings (loss) before interest and taxes	244	186	430	(203)	648	445
Net interest expense	256	–	256	242	–	242
Income tax expense (recovery)	(8)	34[10]	26	102	(84)[10]	18
Net earnings (loss)	(4)	152	148	(547)	732	185
Non-controlling interests	29	–	29	37	–	37
Net earnings (loss) attributable to TransAlta shareholders	(33)	152	119	(584)	732	148
Preferred share dividends	38	–	38	31	–	31
Net earnings (loss) attributable to common shareholders	(71)	152	81	(615)	732	117
Weighted average number of common shares outstanding in the period	264		264	235		235
Net earnings (loss) per share attributable to common shareholders	(0.27)	–	0.31	(2.62)	–	0.50

* *Please refer to Note 3 of our audited consolidated financial statements for additional information regarding the restatements.*
1 *Impacts associated with certain de-designated and ineffective hedges.*
2 *Flood-related maintenance costs.*
3 *Decrease in finance lease receivable.*
4 *Comparable portion of insurance recovery received.*
5 *Gain on sale of PP&E that is included in depreciation and amortization for presentation purposes.*
6 *Mine depreciation that is included in fuel and purchased power for presentation purposes.*
7 *Total adjustments for gain on sale of PP&E, mine depreciation, and flood-related maintenance costs.*
8 *Non-comparable item.*
9 *Reclassification to include in EBITDA.*
10 *Net tax effect of all non-comparable items.*
11 *Includes impacts associated with certain de-designated and ineffective hedges and impacts to revenue associated with Sundance Units 1 and 2 to provide period over period comparability.*
12 *Non-comparable portion of inventory writedown.*
13 *Writeoff of Project Pioneer costs.*
14 *Total net adjustments for gain on sale of PP&E and mine depreciation.*
15 *Total net adjustments for impacts to revenue associated with Sundance Units 1 and 2 and decrease in finance lease receivable.*

Year ended Dec. 31	2011 *(Restated)**		
	Reported	Comparable adjustments	Comparable total
Revenues	2,618	(167)[1]	2,451
Fuel and purchased power	895	–	895
Gross margin	1,723	(167)	1,556
Operations, maintenance, and administration	552	(6)[2]	546
Taxes, other than income taxes	27	–	27
Finance lease income	(8)	(3)[3]	(11)
Gain on sale of property, plant, and equipment	–	(10)[4]	(10)
Mine depreciation	–	(40)[5]	(40)
Earnings before interest, taxes, depreciation, and amortization	1,152	(108)	1,044
Depreciation and amortization	482	46[6]	528
Asset impairment charges	17	(17)[7]	–
Other	–	(37)[8]	(37)
Operating income	653	(100)	553
Equity income	14	–	14
Gain on sale of assets	16	(16)[7]	–
Other income	2	–	2
Foreign exchange loss	(3)	–	(3)
Reserve on collateral	(18)	18[7]	–
Earnings before interest and taxes	664	(98)	566
Net interest expense	215	–	215
Income tax expense	106	(40)[9]	66
Net earnings	343	(58)	285
Non-controlling interests	38	–	38
Net earnings attributable to TransAlta shareholders	305	(58)	247
Preferred share dividends	15	–	15
Net earnings attributable to common shareholders	290	(58)	232
Weighted average number of common shares outstanding in the period	222		222
Net earnings per share attributable to common shareholders	1.31		1.05

** Please refer to Note 3 of our audited consolidated financial statements for additional information regarding the restatements.*

1 *Includes impacts associated with certain de-designated and ineffective hedges and impacts to revenue associated with Sundance Units 1 and 2 to provide period over period comparability.*
2 *Writedown of wind development costs.*
3 *Decrease in finance lease receivable.*
4 *Gain on sale of PP&E that is included in depreciation and amortization for presentation purposes.*
5 *Mine depreciation that is included in fuel and purchased power for presentation purposes.*
6 *Total net adjustments for gain on sale of PP&E, mine depreciation, and writedown of capital spares.*
7 *Non-comparable item.*
8 *Total net adjustments for revenues associated with Sundance Units 1 and 2 and decrease in finance lease receivable.*
9 *Net tax effect of all non-comparable items.*

Funds from Operations, Free Cash Flow, Funds from Operations per Share, and Free Cash Flow per Share

Presenting these items 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. Starting in 2013, we have adjusted the calculation of free cash flow to be calculated as FFO less sustaining capital expenditures, dividends paid on preferred shares, and distributions paid to subsidiaries' non-controlling interests. FFO per share and free cash flow per share are calculated using the weighted average number of common shares outstanding during the period:

Year ended Dec. 31	**2013**	2012	2011
Cash flow from operating activities	**765**	520	690
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	204	-
Impacts to working capital associated with California claim	**27**	-	-
Payment of restructuring costs	**5**	5	-
Flood-related maintenance costs	**5**	-	-
Decrease in finance lease receivable	**1**	3	3
Change in non-cash operating working capital balances	**(74)**	56	119
FFO	**729**	788	812
Deduct:			
Sustaining capital expenditures	**(341)**	(439)	(319)
Dividends paid on preferred shares	**(38)**	(32)	(15)
Distributions paid to subsidiaries' non-controlling interests	**(55)**	(59)	(61)
Free cash flow	**295**	258	417
Weighted average number of common shares outstanding in the period	**264**	235	222
FFO per share	**2.76**	3.35	3.66
Free cash flow per share	**1.12**	1.10	1.88

A reconciliation of comparable EBITDA to FFO is as follows:

Year ended Dec. 31	**2013**	2012	2011
Comparable EBITDA	**1,023**	1,015	1,044
Unrealized (gain) loss from risk management activities	**(27)**	27	(48)
Impacts to revenue associated with Sundance Units 1 and 2 to provide period over period comparability	**-**	20	40
Cash interest expense	**(238)**	(225)	(196)
Provisions	**11**	11	22
Cash income tax expense	**(39)**	(13)	(26)
Realized foreign exchange loss	**-**	(4)	-
Decommissioning and restoration costs settled	**(24)**	(34)	(33)
Restructuring provision	**3**	(13)	-
Sundance Units 1 and 2 return to service	**-**	(211)	-
Gain on sale of (reserve on) collateral	**-**	15	-
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	204	-
Payment of restructuring costs	**5**	5	-
Flood-related maintenance costs	**5**	-	-
Other non-cash items	**10**	(9)	9
FFO	**729**	788	812

Financial Position

The following chart outlines significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2012 to Dec. 31, 2013:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	15	Timing of receipts and payments
Accounts receivable	(124)	Timing of customer receipts
Inventory	(16)	Writedown of coal inventory partially offset by higher average coal costs
Investments	20	Additions to equity investments
Finance lease receivable (current and long-term)	21	Favourable changes in foreign exchange rates
Property, plant, and equipment, net	149	Purchase of wind farm in Wyoming and additions partially offset by asset retirements and depreciation
Goodwill	13	Purchase of Wyoming wind farm
Intangible assets	39	Purchase of wind farm in Wyoming partially offset by amortization
Deferred income tax assets	28	Net deferred income tax recovery
Risk management assets (current and long-term)	118	Price movements and changes in underlying positions and settlements
Accounts payable and accrued liabilities	(48)	Timing of payments and lower capital accruals
Dividends payable	10	Increased dividends due to increase in total shares outstanding
Long-term debt (including current portion)	105	Issuance of senior notes, partially offset by use of net proceeds received on sale of the non-controlling interest in TransAlta Renewables to pay down borrowings on our credit facility
Finance lease obligation (including current portion)	25	Finance lease for mining equipment at the Highvale Mine
Decommissioning and other provisions (current and long-term)	20	Increase in decommissioning and other provisions
Deferred credits and other long-term liabilities	39	California claim and reimbursement received for New Richmond, partially offset by decrease in defined benefit accrual
Deferred income tax liabilities	(14)	Net deferred income tax recovery
Risk management liabilities (current and long-term)	74	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	(112)	Share dividends partially offset by issuance of common shares and net earnings for the period
Non-controlling interests	187	Sale of the non-controlling interest in TransAlta Renewables, partially offset by non-controlling interests' portion of net earnings net of distributions to non-controlling interests

Financial Instruments

Financial instruments are used to manage our exposure to interest rates, commodity prices, and 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, changes in fair value will generally not affect earnings until the financial instrument is settled.

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

Some 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. 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.

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 in net earnings mark-to-market gains and losses 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.

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.

In a fair value hedge, changes in the fair value of the hedging instrument (an interest rate swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings. The carrying amount of long-term debt subject to the hedge is adjusted for losses or gains associated with the hedged risk, with the corresponding amounts recognized in net earnings. As a result, only the net ineffectiveness is recognized in net earnings.

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, primarily related to capital expenditures.

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 related to interest expense resulting from anticipated issuances of long-term debt.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in other comprehensive income ("OCI"). These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

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 in net earnings 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. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We attempt to manage our foreign exchange translation 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.

Non-Hedges

Financial instruments not designated as hedges are used to reduce commodity price, foreign exchange, and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings in the period in which the change occurs.

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, 2013, Level III instruments had a net asset carrying value of $66 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, 2012.

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 TSR 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, with 50 per cent of the common shares released to the participant and the remaining 50 per cent 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, 2013, accounts receivable from employees under the plan totalled $3 million (2012 – $4 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. Except for the newly acquired SunHills plans, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The most recent actuarial valuation for accounting purposes of the registered and supplemental pension plans was conducted as at Dec. 31, 2013 for the Canadian pension plan and Jan. 1, 2013 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 most recent actuarial valuation of these plans was conducted at Dec. 31, 2013 for the Canadian plan and Jan. 1, 2013 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 $63 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, 2013 and 2012:

Year ended Dec. 31	**2013**	2012	**Explanation of change**
Cash and cash equivalents, beginning of year	**27**	49	
Provided by (used in):			
Operating activities	**765**	520	Favourable changes in working capital of $307 million, net of a $27 million impact associated with the California claim in 2013 and a $204 million impact associated with the Sundance Units 1 and 2 arbitration in 2012, partially offset by lower cash earnings of $62 million
Investing activities	**(703)**	(1,048)	Decrease in acquisition of finance lease of $312 million, a decrease in additions to PP&E and intangibles of $149 million, an increase in realized gains on financial instruments of $26 million, and an increase in proceeds on sale of PP&E of $11 million, partially offset by the acquisition of the Wyoming wind farm for $109 million, an increase in equity investments of $17 million, a net negative impact of $12 million related to changes in collateral received from or paid to counterparties, and a decrease in investing non-cash working capital balances of $27 million
Financing activities	**(47)**	504	Decrease in proceeds on issuance of common shares of $293 million, a decrease in borrowings under credit facilities of $271 million partially due to the use of net proceeds received from the sale of the non-controlling interest in TransAlta Renewables to pay down borrowings on our credit facility, a decrease in proceeds on issuance of preferred shares of $217 million, an increase in common share cash dividends of $12 million, partially offset by an increase in proceeds on sale of non-controlling interest in subsidiary of $207 million, an increase in realized gains on financial instruments of $46 million, a decrease in long-term debt payments of $14 million, and an increase in proceeds on the issuance of long-term debt of $10 million
Translation of foreign currency cash	**-**	2	
Cash and cash equivalents, end of year	**42**	27	

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 $29 million and unfavourable changes in working capital of $141 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	

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 $4.3 billion as at Dec. 31, 2013 compared to $4.2 billion as at Dec. 31, 2012. Total long-term debt increased from Dec. 31, 2012, primarily due to unfavourable changes in foreign exchange rates.

Credit Facilities

At Dec. 31, 2013, we had a total of $2.1 billion (2012 – $2.0 billion) of committed credit facilities, of which $0.9 billion (2012 – $0.8 billion) is not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2013, the $1.2 billion (2012 – $1.3 billion) of credit utilized under these facilities was comprised of actual drawings of $0.8 billion (2012 – $1.0 billion) and letters of credit of $0.4 billion (2012 – $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2017, with the remainder comprised of bilateral credit facilities, of which $0.3 billion matures in 2017 and $0.2 billion matures in the fourth quarter of 2015. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.9 billion available under the credit facilities, we have $42 million of available cash.

Share Capital

At Dec. 31, 2013, we had 268.2 million (2012 – 254.7 million) common shares issued and outstanding. During the year ended Dec. 31, 2013, 13.5 million (2012 – 31.1 million) common shares were issued for $186 million (2012 – $456 million), which was comprised of dividends reinvested under the terms of the Plan. During 2012, we issued 9.7 million common shares for $159 million for dividends reinvested under the terms of the Plan, 21.2 million common shares were issued through a public offering for total net proceeds of $295 million, and 0.2 million common shares were issued for proceeds of $2 million.

At Dec. 31, 2013, we had 32.0 million (2012 – 32.0 million) preferred shares issued and outstanding.

On Feb. 19, 2014, we had 270.4 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, 2013, we provided letters of credit totalling $370 million (2012 – $336 million) and cash collateral of $21 million (2012 – $19 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, 2013, the excess of current liabilities over current assets is $105 million (2012 – $436 million). The excess of current liabilities over current assets decreased $331 million compared to 2012 due to a decrease in the current portion of long-term debt and current risk management liabilities, partially offset by a decrease in accounts receivable and current risk management assets.

Capital Structure

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

	2013		2012	
As at Dec. 31	Amount	%	Amount	%
Debt, net of available cash and cash equivalents	**4,280**	**55**	4,192	56
Non-controlling interests	**517**	**7**	330	4
Equity attributable to shareholders	**2,906**	**38**	3,018	40
Total capital	**7,703**	**100**	7,540	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:

	Natural 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]	Total
2014	39	11	12	172	42	209	211	696
2015	14	12	10	123	26	689	178	1,052
2016	13	9	10	126	25	29	172	384
2017	13	3	8	41	20	854	162	1,101
2018	12	3	7	41	27	732	123	945
2019 and thereafter	103	6	52	501	174	1,807	783	3,426
Total	**194**	**44**	**99**	**1,004**	**314**	**4,320**	**1,629**	**7,604**

As part of the Bill signed into law in the State of Washington and the subsequent 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 in 2015 and 2017.
2 Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.

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") and sulphur dioxide ("SO_2") 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. 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

In the U.S., on June 25, 2013, President Obama announced his Climate Action Plan, which sets out plans for GHG emission standards to be imposed by the Environmental Protection Agency ("EPA") for new and existing power plants. Subsequently, on Sept. 20, 2013, the EPA issued draft regulations for new coal-fired plants that, if adopted, would require new coal plants to achieve GHG emissions of no more than 1,100 pounds per MWh of carbon dioxide (significantly below current average emissions for coal-fired plants) in order to be approved. These regulations are expected to be finalized by mid-2014. These proposed regulations do not currently have an impact on our operations. Standards for existing units are to be finalized by June 2015. State implementation plans are to be completed a year later. There will be few additional details as to how existing coal (and potentially natural gas) units might be treated until the EPA releases a draft rule. Furthermore, the U.S. Supreme Court has agreed to review a challenge to the EPA's right to regulate GHG emissions from stationary sources like power plants, so the future of this regulation is uncertain.

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 Bill passed in 2011.

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 2013, we estimate that 27.5 million tonnes of GHGs with an intensity of 0.801 tonnes per MWh (2012 – 27 million tonnes of GHGs with an intensity of 0.816 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. Commercial operations began at our 68 MW New Richmond wind facility during the first quarter of 2013 and on Dec. 20, 2013 we completed the acquisition of a 144 MW wind farm in Wyoming. 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 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 completed at our Keephills and Sundance plants have improved 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.

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 emissions 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 2013 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, sulphur 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 or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. 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 our business and anticipated financial performance including, for example: the timing and the completion and commissioning of projects under development, including major projects, and their attendant costs; expectations regarding AESO's plans for resolving regional constraints on Alberta's transmission system; our estimated spend on matters relating to the 2013 flood in Alberta, 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; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; expectations for the outcome of existing or potential legal and contractual claims; investigations and disputes; 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 and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations regarding the renewal of collective bargaining agreements; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; the estimated contribution of Energy Trading activities to gross margin; and expectations relating to the performance of TransAlta Renewables' assets.

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 and our ability to carry out the repairs in a cost-effective manner or timely manner; 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; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions; and the satisfactory receipt of applicable regulatory approvals for the closing of the Wyoming acquisition. 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 2014 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.

2014 Outlook

Business Environment

Demand

Alberta electricity demand is expected to grow at an average rate of 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 growth in Ontario is expected to remain weak at below one per cent.

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 roughly flat reserve margins over the next several years based on generation projects currently under construction and forecasted load growth. The Ontario reserve margin will also remain relatively flat until expected nuclear refurbishments take capacity offline around 2016. 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, 20 MW of waste heat and biomass projects were completed in 2013 and 40 MW are currently under construction. Currently, there are 300 MW of wind generation facilities under construction and approximately 1,000 MW have received regulatory approval. In total, approximately 2,300 MW of wind generation is in the AESO interconnection queue. However, not all announced generation is expected to be built and some projects cannot be developed prior to transmission expansions.

Ontario and the Pacific Northwest are also expected to add renewable capacity in the next several years. In the Pacific Northwest, the expiry of the wind production tax credit is expected to drive capacity to come online before the end of 2015. Ontario is expected to bring on in excess of 1,000 MW of renewable capacity, made up primarily of wind, solar, and biomass projects.

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 4,250 MW of cogeneration capacity and another 300 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

The existing Alberta, Ontario, and Pacific Northwest transmission systems are congested and aging, resulting in constraints on our generation operations as expected electricity flows exceed the systems' current capacity. The reinforcement of the transmission system in Alberta will alleviate congestion on major transmission paths, but there will continue to be congestion at the regional level. Upgrades to the transmission system in Ontario will alleviate congestion in some parts of the province, but generation in northern Ontario will continue to be constrained by limited transmission capacity.

Cost pressures will continue to create interest in ways to introduce competition into the development of transmission facilities. Future transmission developments in both Alberta and Ontario could become subject to competitive procurement processes and create opportunities to bid on those developments. The AESO is currently running an RFP process for the first of two transmission lines between the Edmonton and Fort McMurray regions. TAMA Transmission is participating in this RFP process and qualified to participate as a proponent in the project. The AESO announced its selection of a short-list of companies, identifying that TAMA Transmission will participate in the next stage of its competitive process for the project. The AESO is expected to start the RFP process on the second line in 2015.

Power Prices

In 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation and fewer planned maintenance outages across the market. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle higher than in 2013 due to marginally higher natural gas prices and an outlook for lower hydro generation compared to 2013.

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 such regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of this MD&A.

In addition, discussions are ongoing 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.

On Jan. 21, 2013, the Ontario government released a discussion paper for public input on reducing GHG emissions in the province, with the stated intent of developing GHG regulations for all major industrial sectors by 2015. No specific targets or regulatory approaches have yet been proposed.

In the U.S., the President's Climate Action Plan provides an indication of how GHG regulation of existing fossil-fuel based generation may unfold, although we expect the implementation process to take several years. Our 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. We expect this agreement may mitigate separate federal action from the EPA. Additionally, new federal air pollutant regulations for the power sector are anticipated, but are not expected to directly affect our coal-fired operations in Washington State.

Effective January 2013, direct deliveries of power to the California Independent System Operator were subject to Cap and Trade Regulations established by the California Air Resource Board. We continue to monitor our GHG inventory into California.

In Australia, the carbon tax implemented in July 2012 remains in place. However, on Nov. 13, 2013, the recently elected Liberal government introduced legislation to repeal the carbon tax by July 2014, and replace it with a Direct Action plan that would fund industry for actions to reduce emissions. The legislation has not yet been passed. While TransAlta's gas-fired operations are subject to the tax, all related costs are flowed to contracted customers.

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

In 2014, we expect slow to moderate growth in all 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 2013. We continue to monitor counterparty credit risk and have established risk management policies to mitigate counterparty risk. 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 2014 primarily due to the commencement of operations at our Solomon power station in Australia. Prior to the effect of any economic dispatching, overall production is expected to increase in 2014 due to lower planned and unplanned outages. Overall availability is expected to be in the range of 88 to 90 per cent in 2014.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 72 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 calendar year. As at the end of 2013, approximately 88 per cent of our 2014 capacity was contracted. The average prices of our short-term physical and financial contracts for 2014 are approximately $55 per MWh in Alberta and approximately U.S.$40 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. Coal costs for 2014, on a standard cost per tonne basis, are expected to be 10 to 12 per cent lower than 2013 due to Sundance Units 1 and 2 operating for a full year and realizing the benefits from insourcing operational accountability from PMRL at the Highvale Mine during 2013.

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 2014 is expected to increase between one to three 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 are recognized in net earnings. For more information on the inventory impairment charges recorded in 2013, 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.

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 2014 objective is for Energy Trading to contribute between $50 million and $65 million in gross margin for the year.

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 2014 is expected to be in line with 2013. 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. Under 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 2014 is expected to be approximately 17 to 22 per cent, which is lower than the statutory tax rate of 25 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital Expenditures

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

Growth and Major Project Expenditures

In 2013, we spent a total of $211 million on growth and major project expenditures, net of any joint venture contributions received. Commercial operations began at our New Richmond wind farm and Sundance Units 1 and 2 were returned to service.

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

	Total Project		2014		
	Estimated spend	Spent to date	Estimated spend	Target Completion date	Details
Project					
Australia natural gas pipeline	86	–	86	Q1 2015	270 kilometer pipeline to supply natural gas to our Solomon power station in Western Australia
Transmission	10	–	10	Q4 2014	Regulated transmission that receives a return on investment
Hydro life extension	15-20	–	15-20	Q4 2014	Generator replacement and turbine runner improvements to extend the life of selected plants
Total major projects and growth	**111-116**	**–**	**111-116**		

Transmission

For the year ended Dec. 31, 2013, a total of $2 million was spent on transmission projects. Transmission projects consist of the major maintenance and reconfiguration of Alberta's transmission networks to reinforce the transmission system and to increase the 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. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

For 2014, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Spent in 2013	Expected spend in 2014
Routine capital	Expenditures to maintain our existing generating capacity	126	110-115
Mining equipment and land purchases[1]	Expenditures related to mining equipment and land purchases	53	45-50
Finance leases	Payments related to mining equipment under finance leases	9	5-10
Planned major maintenance	Regularly scheduled major maintenance	153	175-190
Total sustaining expenditures		**341**	**335-365**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	33	10-15
Total sustaining and productivity expenditures		**374**	**345-380**

During the year, we acquired $33 million of mining equipment under finance leases and we made principal repayments of $9 million.

1 An additional $12 million for mining equipment in use is not payable until 2014.

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

Year ended Dec. 31	2013	2012	2011
Capitalized	**153**	286	184
Expensed	**–**	–	2
	153	286	186
GWh lost	**3,264**	4,186	2,872

Details of the 2014 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2014
Capitalized	120-130	55-60	175-190
Expensed	–	0-5	0-5
	120-130	55-65	175-195

	Coal	Gas and Renewables	Total
GWh lost	2,200-2,210	400-410	2,600-2,620

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 risk 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 and Chief Investment Officer and is comprised of the Vice-President and Treasurer, Executive Vice-President Trading and Marketing, Vice-President Risk Management, Vice-President Regulatory and 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 approval by the Investment Committee and the Board of Directors.

The Investment Committee is chaired by our Chief Financial and Chief Investment Officer and is comprised of the Chief Executive Officer, Chief Legal Officer, the Executive Vice-President Corporate Services, Vice-President Mergers and Acquisitions, Vice-President Risk Management, and Vice-President Construction. It reviews and approves all major capital expenditures including growth, productivity, life extensions, and major coal outages. Projects that are approved by the committee will then be put forward for approval by the Board of Directors.

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, 2013 associated with our proprietary energy trading activities was $2 million (2012 – $2 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 2013. 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. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

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 Segment and Capital and Asset Reporting group in order to be proactive in plant maintenance so that our plants 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	21

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 Electric 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 2013, we had approximately 90 per cent (2012 – 90 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 emissions costs by entering into various emission trading arrangements, and
- selectively using hedges, where available, to set prices for fuel.

In 2013, 64 per cent (2012 – 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 (2012 – 100 per cent) of our purchased coal costs were contractually fixed.

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

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$ 1.00/MWh	8
Natural gas price	$ 0.10/GJ	1
Coal price	$ 1.00/tonne	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 or for which have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties. All of the coal used in generating activities in Alberta is from reserves permitted through coal rights we have purchased. The coal used in generating activities in Centralia is secured through long-term supply contracts,
- 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 NOx, 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.

We are a founder of the Canadian Clean Power Coalition 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, 2012. We had no material counterparty losses in 2013, 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, 2013 is provided below:

Counterparty credit rating	Net exposure amount
Investment grade	349
Non-investment grade	–
No external rating, internally rated as investment grade	50
No external rating, internally rated as non-investment grade	4

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 $23 million (2012 – $25 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, 2013, we have hedged approximately 96 per cent (2012 – 94 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	1

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 while the opposite impact will be seen on 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, 2013, approximately 21 per cent (2012 – 24 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	0.25	2

Project Management Risk
As we are currently working on three 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 is 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 2013, 54 per cent (2012 – 43 per cent) of our labour force was covered by 12 (2012 – 11) collective bargaining agreements. In 2013, five (2012 – two) agreements were renegotiated. We anticipate negotiating five agreements in 2014. 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 Legal and Regulatory Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electric system operators, and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design, and we engage in market-sponsored stakeholder engagement processes. Through these and other avenues, we engage 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 transmission capacity for existing and new generation are key in our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continue to increase because new connections to the power system are consuming transmission capacity quicker than it is being added by new transmission developments.

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[1]
Tax rate	1	–

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2013 was 17 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 renewal of the insurance policies on December 31. The deductible for 2014 catastrophic losses (earthquake, flood, and wind) was increased for 2014. 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.

1 *A one per cent change in the tax rate applied to current year pre-tax earnings would not result in a material impact to net earnings. Based on current year pre-tax net earnings, a change in the tax rate of approximately nine per cent would be required to result in a $1 million impact on net earnings.*

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 our audited consolidated financial statements within this Annual Report. 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 utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

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, credit valuation, and location differentials. Energy Trading includes, in Level II, over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, 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 for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models 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. We also have various contracts with terms that extend beyond a liquid trading period. As forward market prices 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.

We have a Commodity Exposure Management Policy (the "Policy"), which governs both the commodity transactions undertaken in our proprietary trading business and those undertaken to manage commodity price exposures in our generation business. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding energy trading Level III fair value measurements are determined by our Risk Management department. Level III fair values are calculated within our Energy Trading Risk Management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the Risk Management and Finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value, or changes to key parameters.

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, 2013 is estimated to be a +/- $105 million (2012 – $26 million) impact to the carrying value of the financial instruments. 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, 2013, PP&E makes up 74 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 2013 and other specific events, net pre-tax asset impairment reversals of $18 million (2012 – charges of $367 million) were recorded related to certain facilities. Refer to the Asset Impairment Charges and Reversals 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 2013, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $585 million (2012 – $564 million), of which $58 million (2012 – $41 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. Please refer to Note 25 of our audited consolidated financial statements within this Annual Report for additional information regarding changes to CGUs in our goodwill impairment assessments.

Goodwill arose on the acquisitions of the Wyoming wind farm, CHD, Merchant Energy Group of the Americas, Inc., and Vision Quest Windelectric Inc. As at Dec. 31, 2013, this goodwill had a total carrying amount of $460 million (2012 – $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 to which goodwill relates, 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 $118 million (2012 – $90 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2013. These assets primarily relate to net operating loss carryforwards. We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $459 million (2012 – $473 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2013. 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 liabilities 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, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. 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 plan assets are comprised primarily of equity and fixed income investments. Fluctuations in the return on plan assets as a result of actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

In 2013, amendments to IFRS accounting rules regarding defined benefit pensions arose, and the expected long-term rate of return on plan assets is no longer an assumption that is used to estimate expected returns on plan assets. Instead, the discount rate is used to determine a net interest cost on the net defined benefit liability (asset), as applicable, and this net interest cost is recognized in net earnings. Despite this change in accounting requirements, the actual returns on plan assets continue to be an important measure, and impacts the determination of the net defined benefit liability recognized on our Consolidated Statements of Financial Position. For the year ended Dec. 31, 2013, the plan assets had a positive return of $44 million, compared to $24 million in 2012.

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, 2013, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $270 million (2012 – $262 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.

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	10	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.

Current Accounting Changes

Adoption of New or Amended IFRS

On Jan. 1, 2013, we adopted the following new accounting standards that were previously issued by the International Accounting Standards Board ("IASB"):

IFRS 10 *Consolidated Financial Statements*

IFRS 10 replaces the parts of International Accounting Standard ("IAS") 27 *Consolidated and Separate Financial Statements* that deal with consolidated financial statements and Standing Interpretations Committee ("SIC") Interpretation 12 *Consolidation – Special Purpose Entities*. IFRS 10 defines the principle of control, establishes control as the basis for determining when entities are to be consolidated, and provides guidance on how to apply the principle of control to identify whether an investor controls an investee. Under IFRS 10, an investor controls an investee when it has all of the following: (i) power over the investee; (ii) exposure, or rights, to variable returns from the investee; and (iii) the ability to affect those returns.

We applied IFRS 10 retrospectively by reassessing whether, on Jan. 1, 2013, we had control of all of our previously consolidated entities. As a result of adopting IFRS 10, no changes arose in the entities we controlled and consolidated.

IFRS 11 *Joint Arrangements*

IFRS 11 replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers.* IFRS 11 provides for a principles-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its involvement in joint arrangements. A joint arrangement is an arrangement in which two or more parties have joint control. Under IFRS 11, joint arrangements are classified as either a joint operation, or a joint venture, whereas under IAS 31, they were classified as a jointly controlled asset, jointly controlled operation or a jointly controlled entity. IFRS 11 requires the use of the equity method of accounting for interests in joint ventures, whereas IAS 31 permitted a choice of the equity method or proportionate consolidation for jointly controlled entities. Under IFRS 11, for joint operations, each party recognizes its respective share of the assets, liabilities, revenues, and expenses of the arrangement, generally resulting in proportionate consolidation accounting.

We applied IFRS 11 retrospectively by reassessing the type of, and accounting for, each joint arrangement in existence at Jan. 1, 2013. No significant impacts resulted.

IFRS 12 *Disclosure of Interests in Other Entities*

IFRS 12 contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint arrangements, associates, and consolidated and unconsolidated structured entities (special purpose entities). The objective of IFRS 12 is that an entity should disclose information that helps financial statement users evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial statements. Disclosures arising from the adoption of IFRS 12 can be found in Notes 14, 18, and 29 of our audited consolidated financial statements within this Annual Report.

IFRS 13 *Fair Value Measurement*

IFRS 13 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. Our adoption of IFRS 13, prospectively on Jan. 1, 2013, did not have a material financial impact upon the consolidated financial position or results of operations; however, certain new or enhanced disclosures are required and can be found in Note 19 of our audited consolidated financial statements within this Annual Report.

IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 *Presentation of Financial Statements* issued in June 2011 were intended to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they subsequently reclassified from OCI to net earnings or not. The Consolidated Statements of Comprehensive Income (Loss) have been reorganized to comply with the required groupings.

IAS 19 *Employee Benefits*

Amendments to IAS 19 *Employee Benefits* are intended to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require the recognition of changes in defined benefit obligations and in fair value of plan assets when they occur, thus eliminating the "corridor approach" previously permitted. All actuarial gains and losses must be recognized immediately through OCI and the net pension liability or asset recognized at the full amount of the plan deficit or surplus. Additional changes relate to the presentation, into three components, of changes in defined benefit obligations and plan assets: service cost and net interest cost is recognized in net earnings and remeasurements are recognized 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.

We calculate the net interest cost for our defined benefit plans by applying the discount rate at the beginning of the reporting period to the net defined benefit liability at the beginning of the reporting period. An expected return on plan assets is no longer calculated and recognized as part of pension expense. The elimination of the corridor method had no impact as we have, since the adoption of IFRS, recognized actuarial gains and losses in OCI in the period in which they occurred.

On adoption, we applied the amendments retrospectively. The impacts as at Dec. 31, 2012 and Jan. 1, 2012, respectively, were an increase in the cumulative prior periods' pre-tax pension expense of $17 million and $11 million ($12 million and $8 million after-tax, respectively), as a result of the application of the net interest cost requirements.

For the year ended Dec. 31, 2012, OM&A expense increased by $4 million (2011 – $7 million) as a result of increased pension expense and net after-tax actuarial losses on defined benefit plans as reported in OCI decreased by $3 million (2011 – $5 million).

Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine* ("IFRIC 20")

IFRIC 20 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.

We recognize a stripping activity asset for our Highvale mine when all of the following are met: (i) it is probable that the future benefit associated with improved access to the coal reserves associated with the stripping activity will be realized; (ii) the component of the coal reserve to which access has been improved can be identified; and (iii) the costs related to the stripping activity associated with that component can be measured reliably. Costs include those directly incurred to perform the stripping activity as well as an allocation of directly attributable overheads. The resulting stripping activity asset is amortized on a unit-of-production basis over the expected useful life of the identified component that it relates to. The amortization is recognized as a component of the standard cost of coal inventory.

As required by the transitional provision of IFRIC 20, we applied the Interpretation to production stripping costs incurred on or after Jan. 1, 2011, which will be the earliest comparative period presented within our annual financial statements for the year ended Dec. 31, 2013, which will result in adjustments to the 2012 earnings. The impacts on the Consolidated Statements of Financial Position as at Dec. 31, 2012 were to recognize $9 million in costs as a stripping activity asset, increase coal inventory by $2 million, both classified within inventory, increase deferred income tax liabilities by $3 million, and decrease retained deficit by $8 million. The impacts on the Consolidated Statements of Financial Position as at Jan. 1, 2012 were to recognize $9 million in costs as a stripping activity asset, decrease coal inventory by $2 million, both classified within inventory, increase deferred income tax liabilities by $2 million, and increase retained earnings by $5 million.

The impact of this change in accounting policy on the Consolidated Statements of Earnings (Loss) for the year ended Dec. 31, 2012 was a reduction of $4 million in fuel and purchased power (2011 – $7 million).

Basic and diluted net earnings per share attributable to common shareholders for 2012 decreased by $0.01 (2011 – nil) as a result of IAS 19 and IFRIC 20 impacts.

IFRS 7 *Financial Instruments: Disclosures*

Amendments to IFRS 7 include 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 resulting disclosures can be found in Note 20 of our audited consolidated financial statements within this Annual Report.

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. We have applied the amendments, as applicable, on Jan. 1, 2013. None of the amendments, which are generally technical and narrow in scope, had a material financial impact upon the consolidated financial position or results of operations.

Future Accounting Changes

New or amended applicable accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied, are as follows:

IFRS 9 *Financial Instruments*

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

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

In November 2013, the IASB issued amendments to IFRS 9 that introduce a new general hedge accounting model intended to be simpler and more closely focus on how an entity manages its risks. Additional amendments to IFRS 9 allow a reporting entity to present changes in its own credit risk associated with liabilities designated at fair value through profit or loss in OCI.

The IASB also removed the Jan. 1, 2015 mandatory effective date from IFRS 9. The IASB will decide on a new effective date when the entire IFRS 9 project is closer to completion. Entities may still early-adopt the finalized and issued provisions of IFRS 9.

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.

IAS 36 *Impairment of Assets (Recoverable Amount Disclosures)*

In May 2013, the IASB issued amendments to the disclosure requirements of IAS 36 *Impairment of Assets.* The amendments clarify that the recoverable amount of an asset or cash-generating unit is to be disclosed only in periods in which an impairment loss has been recognized or reversed. Additional disclosures regarding the level of the IFRS 13 fair value hierarchy and information about valuation techniques and key assumptions are required, in certain circumstances, when an impairment loss or reversal has been recognized and the recoverable amount is based on fair value less costs of disposal. The amended disclosure requirements apply retrospectively to annual reporting periods beginning on or after Jan. 1, 2014.

IAS 32 *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 and 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.

Selected Quarterly Information

	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Revenue	**540**	**542**	**623**	**587**
Net earnings (loss) attributable to common shareholders	**(11)**	**15**	**(9)**	**(66)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.04)**	**0.06**	**(0.03)**	**(0.25)**
Comparable earnings per share	**0.12**	**0.03**	**0.15**	**0.00**

	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Revenue	644	398	522	646
Net earnings (loss) attributable to common shareholders	88	(798)	56	39
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.39	(3.52)	0.24	0.15
Comparable earnings (loss) per share	0.20	(0.10)	0.18	0.22

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

Controls and Procedures

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 *Securities Exchange Act of 1934*, as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is 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, 2013, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.