TransAlta Corporation

Management's Discussion and Analysis

December 31, 2014

Plant Summary

As of January 31, 2015	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	100%	13	Hydro	Merchant	–
	Interlakes, AB	5	100%	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100%	3	Hydro	Merchant	–
	Three Sisters, AB	3	100%	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100%	3	Hydro	Merchant	–
	St. Mary, AB	2	100%	2	Hydro	Merchant	–
	Upper Mamquam, BC	25	100%	25	Hydro	LTC	2025
	Pingston, BC	45	50%	23	Hydro	LTC	2023
	Bone Creek, BC	19	100%	19	Hydro	LTC	2031
	Akolkolex, BC	10	100%	10	Hydro	LTC	2015
	Summerview 1, AB	70	100%	70	Wind	Merchant	–
	Summerview 2, AB	66	100%	66	Wind	Merchant	–
	Ardenville, AB	69	100%	69	Wind	Merchant	–
	Blue Trail, AB	66	100%	66	Wind	Merchant	–
	Castle River, AB[8]	44	100%	44	Wind	Merchant	–
	McBride Lake, AB	75	50%	38	Wind	LTC	2024
	Soderglen, AB	71	50%	35	Wind	Merchant	–
	Cowley Ridge, AB	16	100%	16	Wind	Merchant	–
	Cowley North, AB	20	100%	20	Wind	Merchant	–
	Sinnott, AB	7	100%	7	Wind	Merchant	–
	Macleod Flats, AB	3	100%	3	Wind	Merchant	–
Total Western Canada		**6,541**		**5,313**			
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	LTC	2029
	Misema, ON	3	100%	3	Hydro	LTC	2027
	Galetta, ON	2	100%	2	Hydro	LTC	2030
	Appleton, ON	1	100%	1	Hydro	LTC	2030
	Moose Rapids, ON	1	100%	1	Hydro	LTC	2030
	Wolfe Island, ON	198	100%	198	Wind	LTC	2029
	Melancthon, ON[9]	200	100%	200	Wind	LTC	2026-2028
	Le Nordais, QC	99	100%	99	Wind	LTC	2033
	Kent Hills, NB[9]	150	83%	125	Wind	LTC	2033-2035
	New Richmond, QC	68	100%	68	Wind	LTC	2033
Total Eastern Canada		**1,484**		**1,334**			
United States 3 Facilities	Centralia, WA	1,340	100%	1,340	Coal	LTC/Merchant	2025
	Wyoming Wind, WY	144	100%	144	Wind	LTC	2028
	Skookumchuck, WA	1	100%	1	Hydro	LTC	2020
Total United States		**1,485**		**1,485**			
Australia 7 Facilities	Parkeston, WA	110	50%	55	Gas	LTC	2016
	Southern Cross, WA[10]	245	100%	245	Gas/Diesel	LTC	2023
	Solomon Power Station	125	100%	125	Gas/Diesel	LTC	2028
	South Hedland[11]	150	100%	150	Gas/Diesel	LTC	2042
Total Australia		**630**		**575**			
Total		**10,140**		**8,707**			

1 *Megawatts are rounded to the nearest whole number; columns may not add due to rounding.*
2 *Accounts for 100% of TransAlta Renewables assets.*
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 Arrangement.*
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 *Comprised of four facilities.*
11 *Plant is under construction and expected to be fully commissioned in mid-2017.*

Management's Discussion and Analysis

Table of Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2014 consolidated financial statements and our 2015 Annual Information Form for the year ended Dec. 31, 2014. Our consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises as issued by the International Accounting Standards Boards ("IASB") and in effect at Dec. 31, 2014. 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. 18, 2015. 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****.*

Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of the financial measures discussed 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 may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. See the Comparable Funds from Operations and Comparable Free Cash Flow, and Earnings and Other Measures on a Comparable Basis sections of this MD&A for additional information.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning 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 assumptions were 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", "project", "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 future financial performance; our success in executing on our growth projects; the timing and the completion and commissioning of projects under development, including major projects such as the South Hedland Power Project, and their attendant costs; expectations regarding the Alberta Electric System Operator's ("AESO") plans for resolving regional constraints on Alberta's transmission system; spending 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, including expectations about the cost savings anticipated from the major maintenance agreement entered into with Alstom; 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 (including estimates of 2015 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), and comparable free cash flow); 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; our expectations regarding proceedings before the Alberta Utilities Commission (the "AUC") as well as those relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; 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 in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; the estimated contribution of Energy Marketing activities to gross margin; and expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets and plans for the sale of contracted assets to TransAlta Renewables.

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 or man-made disasters; the threat of domestic terrorism and cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; 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, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays in the permitting and construction of the South Hedland Power Project and the construction of the Australia Natural Gas Pipeline; failure to proceed with plans for the sale of contracted assets to TransAlta Renewables as a result of failure to agree to commercial terms with the independent directors of TransAlta Renewables, adverse market conditions or failure to obtain any required regulatory, shareholder or other third party approvals; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

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 2015 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.

Highlights

Consolidated Highlights

Year ended Dec. 31	**2014**	2013	2012
Revenues	**2,623**	2,292	2,210
Comparable EBITDA[1]	**1,036**	1,023	1,015
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Comparable net earnings attributable to common shareholders[1]	**68**	81	117
Comparable funds from operations[1]	**762**	729	788
Cash flow from operating activities	**796**	765	520
Comparable free cash flow[1]	**295**	295	258
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.52**	(0.27)	(2.62)
Comparable net earnings per share[1]	**0.25**	0.31	0.50
Comparable funds from operations per share[1]	**2.79**	2.76	3.35
Comparable free cash flow per share[1]	**1.08**	1.12	1.10
Dividends paid per common share	**0.83**	1.16	1.16

As at Dec. 31	**2014**	2013[2]
Total assets	**9,833**	9,624
Total long-term liabilities	**4,504**	5,337

Financial Highlights

- Comparable EBITDA totalled $1,036 million in 2014 compared to $1,023 million in 2013. Strong availability throughout our generation portfolio, improved operational performance at Canadian Coal, higher than planned margins delivered by our Energy Marketing Segment, and a robust hedging strategy offset the impact of much lower power prices in Alberta. Prices in Alberta averaged $49 per megawatt hour ("MWh") in 2014, compared to $80 per MWh in 2013. Our strategy of having a highly contracted portfolio limited the impact of price fluctuations.
- Comparable FFO for 2014 increased $33 million to $762 million as the FFO for 2013 excluded higher amounts of unrealized mark-to-market gains included in EBITDA.
- Comparable net earnings attributable to common shareholders was $68 million ($0.25 per share) in 2014 compared to $81 million ($0.31 per share) in 2013. The decrease in 2014 was primarily due to lower ownership interest in TransAlta Renewables following the public offerings of TransAlta Renewables common shares.
- Reported net earnings attributable to common shareholders was $141 million ($0.52 net earnings per share) in 2014, compared to a net loss of $71 million ($0.27 net loss per share) for 2013, and a net loss of $615 million ($2.62 net loss per share) in 2012. The increase in 2014 is attributable primarily to the change in value of certain de-designated and economic hedges in place at U.S. Coal, driven by decreases in future power prices at the end of the year, and the loss on assumption of pension obligations in 2013. The net earnings for 2013 also include a $56 million settlement of a claim relating to power trading activities in California in 2000 to 2001. Higher losses were recorded in 2012 due to the Sundance Units 1 and 2 return to service decision, as well as impairment at U.S. Coal.

1 These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings and cash flow trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow, and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

2 After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.

Strategic Initiative Highlights

During the year we continued to make significant progress to grow our portfolio of highly contracted assets, improve our operating performance, and strengthen our financial condition through initiatives such as:

- Permitted and commenced construction in January 2015 on a 150 megawatt ("MW") combined cycle gas power station in South Hedland, Western Australia, which we will own and operate. The project is estimated to cost approximately AUD$570 million to build. The fully contracted power station is expected to be commissioned and delivering power to customers in the first half of 2017.
- Significantly advanced construction with a joint venture partner of an AUD$178 million natural gas pipeline to our Solomon power station. We hold a 43 per cent interest in the joint venture. The project is on schedule and within budget, with expected commencement of commercial operations in the first quarter of 2015.
- Strengthened our financial position by reducing our debt by approximately $500 million, before the effects of changes in foreign exchange rates, through the sale of non-strategic investments for proceeds of $205 million, an issuance of preferred shares for $165 million, and completion of a secondary offering of common shares of TransAlta Renewables for $136 million. We have also refinanced over $400 million of credit facilities and maturing long-term debt by way of a senior notes offering, due in 2017.
- Entered into an agreement with Alstom to provide major maintenance for 10 major maintenance projects over the next three years at our Keephills and Sundance plants. The new arrangement is expected to deliver an average 15 per cent cost reduction per turnaround and shorter turnaround times for major maintenance work, resulting in estimated direct cost savings of $34 million over the full term of the agreement.
- Resized the annualized common share dividend to $0.72 from $1.18 to align with our growth and financial objectives.
- Continued execution of our hydro life extension plan, sustaining our advantage as the first hydro power producer in Alberta.

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 2014. Our ultimate goal is to achieve zero injury incidents. We achieved our best results ever for safety performance in 2014.

Year ended Dec. 31	2014	2013	2012
IFR	**0.86**	0.93	0.89

Operational Results

Year ended Dec. 31	2014	2013	2012
Availability *(%)*[1]	**89.7**	85.5	88.4
Adjusted availability *(%)*[1,2]	**90.5**	87.8	90.0
Production *(GWh)*[1]	**45,002**	42,482	38,750
Comparable EBITDA			
Generation Segment			
Canadian Coal	**386**	309	373
U.S. Coal	**62**	66	148
Gas	**309**	327	312
Wind	**177**	180	151
Hydro	**85**	147	127
Total Generation Segment	**1,019**	1,029	1,111
Energy Marketing Segment[3]	**76**	61	(13)
Corporate Segment	**(59)**	(67)	(83)
Total comparable EBITDA	**1,036**	1,023	1,015

- **Canadian Coal**: Comparable EBITDA increased by $77 million to $386 million in 2014 compared to $309 million in 2013 and $373 million in 2012. The improvement is primarily driven by increased availability, from 80.9 per cent in 2013 to 88.6 per cent in 2014 and the reduction of coal costs. After assuming operations of the Highvale mine in 2013, we have reduced our annual coal costs by over $30 million year-over-year in 2014 through greater efficiency and productivity, and a reduction in the transition costs. Our contract profile in Alberta and our hedging strategy significantly mitigated the impact of lower prices in Alberta. Sundance Units 1 and 2, which returned to service in the second half of 2013, have been performing well with availability in excess of 90 per cent.
- **U.S. Coal**: Comparable EBITDA decreased by $4 million to $62 million in 2014 as 2013 comparable EBITDA included favourable adjustments related to prior period costs and provisions. Margins otherwise increased as we further optimized real-time operations against the spot market, estimated marginal costs, and fixed-price contracts. The 2012 results included larger volumes of higher-priced hedges.
- **Gas**: Comparable EBITDA decreased by $18 million to $309 million in 2014 compared to $327 million in 2013 and $312 million in 2012, primarily due to lower Alberta prices impacting our Poplar Creek facility and the effects of the new contract in Ottawa. Compared to 2012, 2013 benefitted from a full year of income from the Solomon power station that was acquired in August 2012.
- **Wind**: Comparable EBITDA was $177 million in 2014 compared to $180 million in 2013 and $151 million in 2012. Increased production from our Wyoming wind facility acquired in December 2013 has mostly offset the effects of lower Alberta prices. In addition to higher prices, 2013 results also include incremental contribution from the New Richmond facility, which was commissioned in March 2013.
- **Hydro**: Comparable EBITDA decreased by $62 million to $85 million in 2014 compared to 2013 due to the reduced potential to use the flexibility of our portfolio during periods of lower volatility. Comparable EBITDA in 2013 was $20 million higher than 2012 due to high prices and market volatility in Alberta.
- **Energy Marketing Segment**: Comparable EBITDA in 2014 was $76 million, up $15 million from $61 million in 2013 due to our ability to capture arbitrage opportunities and optimize our energy marketing assets during extraordinarily volatile market conditions in the first and fourth quarters of 2014. The business has shifted its focus toward lower-risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.
- **Corporate Segment**: Corporate overhead costs decreased by $8 million in 2014 compared to 2013 due to a change in the way allocations are made within the organization. Reductions in corporate costs from a restructuring in 2012 have been sustained.

1 *Availability includes assets under generation operations and finance leases and excludes Hydro assets and Equity Investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.*

2 *Adjusted for economic dispatching at U.S. Coal.*

3 *The Segment changed its name from "Energy Trading" in 2014 following a shift in focus toward lower-risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.*

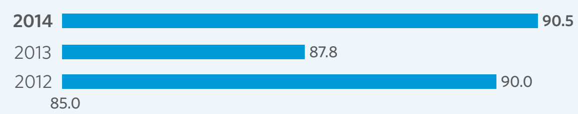
Availability and Production

Our availability in 2014, after adjusting for economic dispatching at U.S. Coal, was 90.5 per cent (2013 – 87.8 per cent; 2012 – 90.0 per cent), which is higher than our long-term target of 88 to 90 per cent. Improvement in our availability for the year ended Dec. 31, 2014 was due to lower unplanned outages at Canadian Coal.

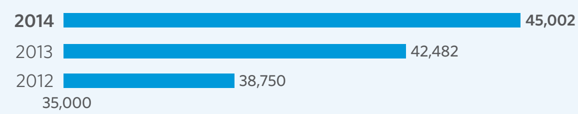
Availability in 2013 was impacted by the Keephills Unit 1 force majeure outage, which was partially offset by lower planned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities.

Production for the year ended Dec. 31, 2014 increased 2,520 gigawatt hours ("GWh") compared to 2013, primarily due to a full year of contribution from Sundance Units 1 and 2, which returned to service in the second half of 2013, as well as the return to service of Keephills Unit 1, which was unavailable for seven months in 2013.

Adjusted Availability *(%)*



Production *(GWh)*



For the year ended Dec. 31, 2013, production increased 3,732 GWh compared to 2012, primarily due to lower economic dispatching at U.S. Coal, Sundance Units 1 and 2 returning to service in the second half of 2013, lower planned outages at the Alberta coal PPA facilities, 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.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable funds from operations and comparable free cash flow provide investors with a proxy for the amount of cash generated from operating activities before changes in working capital, and provide the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FFO per share and comparable free cash flow per share are calculated using the weighted average number of common shares outstanding during the year.

Year ended Dec. 31	2014	2013	2012
Cash flow from operating activities	**796**	765	520
Change in non-cash operating working capital balances	**(73)**	(74)	56
Cash flow from operations before changes in working capital	**723**	691	576
Settlement of 2000 to 2001 California claim	**33**	27	–
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**–**	–	204
TAMA Transmission bid costs	**5**	–	–
Other non-comparable items	**1**	11	8
Comparable FFO	**762**	729	788
Deduct:			
Sustaining capital	**(342)**	(341)	(439)
Dividends paid on preferred shares	**(41)**	(38)	(32)
Distributions paid to subsidiaries' non-controlling interests	**(84)**	(55)	(59)
Comparable free cash flow	**295**	295	258
Weighted average number of common shares outstanding in the year	**273**	264	235
Comparable FFO per share	**2.79**	2.76	3.35
Comparable free cash flow per share	**1.08**	1.12	1.10

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Year ended Dec. 31	2014	2013	2012
Comparable EBITDA	**1,036**	1,023	1,015
Unrealized losses (gains) from risk management activities	**4**	(27)	27
Interest expense	**(236)**	(238)	(225)
Provisions	**-**	11	11
Current income tax expense	**(33)**	(39)	(13)
Realized foreign exchange gain (loss)	**11**	-	(4)
Decommissioning and restoration costs settled	**(16)**	(24)	(34)
Restructuring charges paid (incurred)	**-**	8	(8)
Impacts to revenue associated with Sundance Units 1 and 2	**-**	-	20
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	204
Sundance Units 1 and 2 return to service	**-**	-	(211)
Gain on sale of collateral	**-**	-	15
Flood-related maintenance costs	**-**	5	-
Other non-cash items	**(4)**	10	(9)
Comparable FFO	**762**	729	788

For the year ended Dec. 31, 2014, comparable FFO increased $33 million to $762 million compared to 2013. The increase in FFO outpaced the increase in EBITDA, as last year's EBITDA included $27 million of unrealized risk management gains. The current year's FFO also includes $11 million in realized foreign exchange gains.

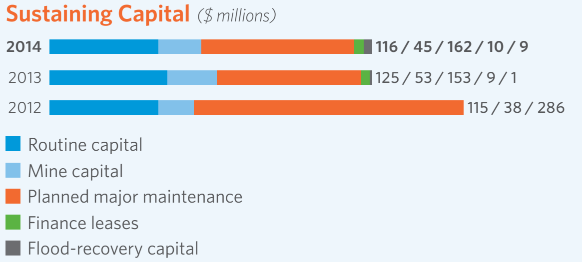
Comparable FFO for the year ended Dec. 31, 2013 decreased $59 million to $729 million compared to 2012, primarily due to higher cash interest and cash taxes as well as differences in timing of cash proceeds associated with power hedges.

Comparable free cash flow for 2014 was $295 million, which was the same as 2013, as the increase in comparable FFO was offset by distributions paid to TransAlta Renewables' public shareholders and improved performance at TransAlta Cogeneration L.P. ("TA Cogen").

For the year ended Dec. 31, 2013, comparable free cash flow increased $37 million compared to 2012, to $295 million, due to lower sustaining capital, partially offset by lower comparable FFO.

Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital that ensures our facilities operate reliably and safely over a long period of time. Our sustaining capital is comprised of: (i) routine capital, (ii) mine capital, (iii) planned major maintenance, and (iv) finance lease. Sustaining capital also includes capital required following the 2013 flood in Alberta, most of which is recoverable from third parties.



Lost production as a result of planned major maintenance is as follows:

Year ended Dec. 31	2014	2013	2012
GWh lost[1]	**1,519**	1,154	2,387

In 2014, routine capital decreased compared to 2013 as a result of fewer unplanned outages during the year. The decrease in mine capital was primarily due to fewer mine support equipment purchases as mining intensity stabilized. Planned major maintenance costs increased primarily due to having five planned outages at Sundance Unit 5, Sundance Unit 6, Keephills Unit 2, U.S. Coal, and Genesee Unit 3 in 2014 compared to four in 2013 at Sundance Unit 4, Keephills Unit 3, U.S. Coal, and Sheerness.

The increase in routine capital in 2013 compared to 2012 was primarily due to the stator replacement at Keephills Unit 1. Mine capital and finance leases increased as a result of the purchase of pre-stripping trucks and other equipment in 2013 in anticipation of production increases associated with the return to service of Sundance Units 1 and 2. Planned major maintenance decreased, as we carried an unusually large number of outages in 2012 in order to sustain greater efficiency in the following years.

Financial Position

We seek to maintain financial flexibility by using multiple sources of capital to finance our business plans, while maintaining a sufficient level of available liquidity to support contracting and trading activities. We are focused on strengthening our financial position and cash flow coverage ratios to support stable investment grade credit ratings. Strengthening our financial position allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are favourable to our financial results, and provides us with better access to capital markets through commodity and credit cycles.

During 2014, we took several steps to strengthen our financial position and reduce debt, raising over $900 million from divestitures, sale of non-controlling interests, sale of preferred shares, and debt refinancing.

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to manage our capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. During the year, we revised the way in which we calculate our ratios in order to align more closely with how we understand some credit rating agencies calculate them. The prior year figures have been restated to conform with the current year's presentation.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

Year ended Dec. 31	2014	2013	2012
Comparable FFO	**762**	729	788
Add: Interest on debt net of interest income and capitalized interest	**236**	238	221
Comparable FFO before interest	**998**	967	1,009
Interest on debt net of interest income	**239**	240	225
Add: 50 per cent of dividends paid on preferred shares	**21**	19	16
Adjusted interest	**260**	259	241
Comparable FFO before interest to adjusted interest coverage *(times)*	**3.8**	3.7	4.2

1 *Lost production excludes periods of planned major maintenance at U.S. Coal, which occur during periods of economic dispatching.*

Comparable FFO before interest to adjusted interest coverage improved slightly compared to 2013 due to higher comparable FFO and lower debt levels. In 2013, comparable FFO before interest to adjusted interest coverage decreased compared to 2012, primarily due to lower comparable FFO and higher interest on debt. Our goal is to maintain this ratio in a range of four to five times.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

Year ended Dec. 31	2014	2013	2012
Comparable FFO	**762**	729	788
Less: 50 per cent of dividends paid on preferred shares	**(21)**	(19)	(16)
Adjusted comparable FFO	**741**	710	772
Period-end long-term debt, including finance lease obligations	**4,056**	4,347	4,217
Add: 50 per cent of issued preferred shares	**471**	391	391
Less: Cash and cash equivalents (excluding restricted cash)	**(43)**	(42)	(25)
Fair value (asset) liability of hedging instruments on debt[1]	**(96)**	(16)	50
Adjusted net debt	**4,388**	4,680	4,633
Adjusted comparable FFO to adjusted net debt *(%)*	**16.9**	15.2	16.7

Adjusted comparable FFO to adjusted net debt increased in 2014 compared to 2013, due to lower debt levels in 2014 and an increase in comparable FFO. In 2013, adjusted comparable FFO to adjusted net debt decreased compared to 2012, due to higher debt levels in 2013 and a decrease in comparable FFO. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable EBITDA

Year ended Dec. 31	2014	2013	2012
Period-end long-term debt, including finance lease obligations	**4,056**	4,347	4,217
Less: cash and cash equivalents	**(43)**	(42)	(25)
Add: 50 per cent of issued preferred shares	**471**	391	391
Fair value (asset) liability of hedging instruments on debt[1]	**(96)**	(16)	50
Adjusted net debt	**4,388**	4,680	4,633
Comparable EBITDA	**1,036**	1,023	1,015
Adjusted net debt to comparable EBITDA *(times)*	**4.2**	4.6	4.6

Adjusted net debt to comparable EBITDA in 2014 improved compared to 2013, primarily due to a decrease in long-term debt. In 2013, adjusted net debt to comparable EBITDA was consistent with 2012. Our goal is to maintain this ratio in a range of three to four times.

1 *Refer to Note 14 of our 2014 Notes to the Annual Financial Statements.*

Business Environment

Overview of our Business

We are one of Canada's largest publicly traded power generators with over 100 years of operating experience. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and use a broad range of generation fuels comprised of coal, natural gas, water, and wind. Our energy marketing operations maximize margins by securing and optimizing high value products and markets for ourselves and our customers in dynamic market conditions.

The **Generation Segment** includes our power generation facilities and related mining operations in Canada, the U.S., and Australia. The full capacity of the facilities in which we have an ownership share is 9,898 MW[1]. At Dec. 31, 2014, our generating assets had 8,846 MW[1] of gross generating capacity in operation. 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. Our renewable energy facilities can also derive income from the sale of environmental attributes.

The majority of our capacity is located in Alberta and 66 per cent of it is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. Alberta PPAs expire at the end of 2017 (Sundance Units 1 and 2) and the end of 2020 (Keephills Units 1 and 2, Sundance Units 3 to 6, Sheerness, and Hydro). We also provide power generation on a contract basis to regional utility and industrial customers in Ontario, Québec, New Brunswick, British Columbia, Alberta, Washington State, Wyoming State, and Western Australia.

Some of our capacity in Alberta and the U.S. Pacific Northwest is not contracted and we sell power into merchant electricity markets. Further, our Alberta PPA coal plants pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of energy and ancillary services in excess of obligations on our Hydro Alberta PPAs. Our contractual arrangements also provide a limited degree of participation in Ontario's electricity market.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest market, which impacts production at U.S. Coal. Typically, hydro facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

The **Energy Marketing Segment** derives revenue and earnings from the marketing and trading of electricity and other energy-related commodities and derivatives. Our energy marketing operations maximize margins by securing and optimizing high value products and markets for ourselves and our customers in dynamic market conditions.

Energy Marketing sells our production through short-term and long-term contracts, ensures cost-effective and reliable fuel supply, and seeks to improve margins by optimizing our portfolio as market conditions change throughout the year. In addition to serving our assets, our marketing team actively markets energy products and services to energy producers and consumers.

Our marketing commitments are backed by our own supply and through the acquisition of third-party supply and proprietary marketing assets, such as transmission, transportation, and storage rights. In the course of managing our portfolio, we actively seek to apply our knowledge of physical power and fuel markets to capture incremental arbitrage margins. All activities are managed within our core markets following strict compliance practices and we impose tight limits on our capital at risk and maintain strict position limits to ensure that our trading strategies meet our low risk tolerances.

Our marketing activities use a variety of instruments to manage risk, earn margins, and gain market information. Our marketing strategies employ shorter-term physical and financial derivative instruments including forwards, swaps, futures, and options in various commodities in regions where we have assets and the markets that directly or indirectly interconnect with those regions. 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.

1 *We measure capacity as net maximum capacity (see Glossary of Key Terms 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 and reflects the basis of consolidation of underlying assets.*

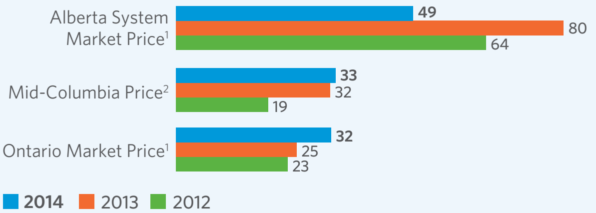
While our strategy is generally consistent between periods, positions held and resulting earnings impacts may vary due to current and forecasted external market conditions. Positions for each region are established based on the market conditions and the risk/reward ratio established for each trade at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

Direct marketing of our own generation is reported in the Generation Segment results. All activities indirectly related to our assets and all other marketing activities are reported in the Energy Marketing Segment.

Electricity Prices

Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, weather, renewable resource availability, and other business environment dynamics. We monitor these trends in prices, and schedule planned maintenance of our generation portfolio, where possible, during times of lower prices.

Average Spot Electricity Prices



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

Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity. Historically, demand for electricity in Alberta, the Pacific Northwest, and Ontario has grown at an average rate of one to three per cent per year. New supply will impact prices in the short term. We expect surplus supply in the Alberta market over the next three to five years to dampen prices.

Renewable generation growth has been strong in all regions for the past several years. 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 greenhouse gas ("GHG") legislation of some form is still expected in Canada and the U.S. While there are many new developments that will likely impact the future supply of electricity, the low cost of our baseload operations means that we expect that our plants will continue to be supported in the market.

Alberta

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. Recent weakness in oil prices is not expected to significantly reduce growth in the near term since many projects are already committed and under construction and will be increasing production despite lower market prices. Weaker oil prices may impact long-term growth prospects as many companies are reducing their capital programs.

During 2014, reserve margins[3] increased primarily as a result of coal capacity returning to service and increased capacity being commissioned. In 2014, Alberta added about 350 MW of wind capacity. Average spot prices decreased significantly compared to 2013, due to increased reserve margin. Electricity prices in 2013 were higher than 2012 due to tighter supply and demand conditions.

In Alberta we expect to see higher reserve margins in 2015 based on additional capacity that is coming online during the year. Combined cycle and cogeneration projects at large oil sands developments are expected to be key sources of new generation supply within Alberta. We believe that continued and growing demand for electricity, including demand for renewable energy, and the potential of increasing amounts of intermittent renewable generation to require additional capacity, may provide an opportunity to increase our generation capacity.

There are currently 1,434 MW of wind generation facilities in operation and projects totalling approximately 1,100 MW of capacity have received regulatory approval. In total, approximately 2,350 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.

3 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.

U.S. Pacific Northwest

As a result of economic conditions, demand growth has been weak in recent years and in 2014 demand growth was relatively flat. Electricity demand is expected to increase by approximately one per cent per year, with potentially stronger growth being partially offset by a large emphasis on energy efficiency across the region.

During 2014, reserve margins were relatively flat. The Pacific Northwest did not see large-scale wind additions in 2014. Average spot prices in 2014 were similar to 2013.

Capacity additions are expected in 2015 as developers seek to take advantage of the wind production tax credit before it expires. The wind production credit expiration is expected to drive stronger wind builds in 2015 and 2016 than was seen in 2014, which is expected to constrain price growth in the market.

Ontario

In recent years, demand growth has been weak due to economic conditions. In 2014, demand growth was relatively flat and is expected to remain weak at below one per cent.

During 2014, reserve margins were relatively flat, even though the increase in renewable capacity has increased supply in much of the year. Ontario added almost 1,500 MW of renewable capacity, including hydro and distributed solar.

Average spot prices for the year ended Dec. 31, 2014 increased compared to 2013 primarily due to extreme cold weather across the entire northeast during the first quarter, which led to higher natural gas prices and increased demand. Prices in 2013 were higher than in 2012 due to higher natural gas prices, partially offset by an increase in supply as a result of nuclear generating plants returning to service.

The reserve margin in the province is not expected to change materially until anticipated nuclear refurbishments take capacity offline around 2016. Ontario is expected to add renewable capacity in the next several years. There is currently 104 MW of wind in the commissioning stages and 479 MW of wind under construction. In addition, 1,651 MW of contracted wind is set to come online during the mid-2015 time frame, of which approximately 18 per cent has received notice to proceed approval from the Independent Electricity System Operator.

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.

Transmission costs in Alberta are forecast to double between 2011 and 2020, and transmission and distribution costs are expected to outweigh energy costs for residential consumers by 2020. This is driving large consumers towards behind-the-fence supply to avoid paying transmission costs and this may constrain growth in the Alberta market. We continue to monitor risks and opportunities associated with transmission on an ongoing basis.

Environmental Legislation and Technologies

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 and hydro, 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.

In the jurisdictions in which we operate, legislators have proposed and enacted regulations to discontinue over time the use of the technologies that our coal-fueled plants currently utilize. Our thermal facilities can also incur costs in relation to their carbon emissions, depending on the jurisdiction in which the facility is located. Our contracted facilities can generally recover those costs from the customer. Conversely, our renewable generation facilities are generally able to realize value from their environmental attributes. We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

Refer to the Climate Change and the Environment section of this MD&A for additional information on these matters.

Strategy and Capability to Deliver Results

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 over the long term, balancing capital allocation, and maintaining financial strength to allow for financial flexibility. Our comparable cash flow growth is driven by optimizing 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 our core markets with a focus on renewables and natural gas-fired generation. Our sponsored, majority-owned subsidiary, TransAlta Renewables, provides us with access to lower cost of capital for contracted asset opportunities. We believe that our significant U.S. tax attributes provide us with an advantage for acquisition opportunities in that country. Furthermore, we are focused on pursuing options for extending the life of our coal assets that are scheduled to retire in Alberta, investing in the Alberta power market, and ensuring that we replace our coal assets in the Pacific Northwest on their retirement. We maintain significant optionality within legislation to optimize cash flows across Canadian Coal units, convert coal units to gas fuel, or integrate newest carbon capture and storage technology in order to achieve these goals.

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 2014, construction began on an AUD$178 million natural gas pipeline to our Solomon power station and we entered into agreements to build and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 million. During 2013, commercial operations began at our 68 MW New Richmond wind farm and we also completed the acquisition of a 144 MW wind farm in Wyoming.

Partnerships are part of our growth strategy. We have developed a partnership, TAMA Power, with Berkshire Hathaway Energy to develop new gas-fired generation in Canada. In prior years, we have joined Capital Power Corporation in the development of Keephills Unit 3 and Genesee Unit 3, and we maintain a significant partnership with Cheung Kong Infrastructure for our subsidiary, TA Cogen.

Financial Strategy

We are focused on strengthening our financial position and maintaining our investment grade credit ratings to provide a solid foundation for our long-cycle, capital-intensive, and commodity-sensitive business. Strengthening our financial position and maintaining our investment grade credit ratings improve our competitiveness by providing greater access to capital markets, lowering our cost of capital, 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 in either Canada or the U.S. when conditions are favourable.

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 2015. We continue to maintain $2.1 billion in committed credit facilities, and as of Dec. 31, 2014, $1.6 billion was available to us.

Our financial strategy is focused on providing competitively priced capital to support growth while simultaneously strengthening our financial position in anticipation of the increased commodity exposure of the post-PPA period. In 2014, we took advantage of favourable capital markets by completing a secondary offering of TransAlta Renewables shares for gross proceeds of approximately $136 million, as well as an offering of U.S.$400 million of senior notes, due in June 2017, and an offering of preferred shares for gross proceeds of $165 million. We have also sold our investments in CE Generation LLC ("CE Gen"), Wailuku Holding Company, LLC ("Wailuku"), the Blackrock Development Project ("Blackrock"), and CalEnergy, LLC ("CalEnergy") for total net proceeds of U.S.$193.5 million to better allocate this capital within our business. Looking forward, we expect continued capital market support for projects that meet our return requirements and risk profile. We also plan to continue to execute our strategy through the sale of contracted assets to our majority-owned subsidiary, TransAlta Renewables, to access a lower cost source of equity, and by issuing additional preferred shares.

Our senior unsecured debt is rated as investment grade: BBB (stable), BBB- (stable), Baa3 (negative), and BBB- (stable); by DBRS, Standard and Poor's ("S&P"), Moody's Investors Services ("Moody's"), and Fitch Ratings ("Fitch"), respectively. Our preferred shares are rated P-3 and Pfd-3 with S&P and DBRS, respectively.[1]

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

Marketing Strategy

On an aggregated portfolio basis, depending on market conditions, we target contracting up to 90 per cent of our expected production for the upcoming year through a combination of Alberta PPAs, long-term contracts with regulated utilities or power authorities, and short- and long-term contracts with small commercial to large industrial customers, supplemented with financial contracts where necessary. This strategy helps protect our cash flow and our financial position through economic cycles. In addition, we are focused on re-contracting our Ontario and Australia facilities where some contracts are set to expire in the 2016 to 2019 period. During 2013, we re-contracted approximately 835 MW of our facilities and investments, in some cases extending the lives of the assets. Currently, approximately 88 per cent of 2015 and approximately 81 per cent of 2016 expected capacity across our fleet has been contracted.

In addition, we have started to leverage our marketing capability by offering products and services to third parties. We anticipate this activity can support sustainable gross margin growth for our Energy Marketing Segment in the coming years.

Operational Strategy

We manage our facilities to achieve stable and predictable operations that are comparatively low cost and balanced with our fleet availability target.

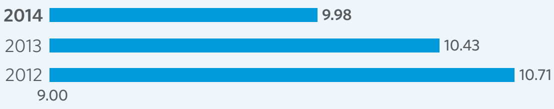
We strive to optimize the availability of our plants throughout the year to meet demand. Our operations and marketing teams work together, in compliance with regional market rules, to optimize production in response to market conditions. However, the ability to meet demand is limited by the requirement to shut down for planned maintenance and by unplanned outages, as well as by reduced production from derates. Our goal is to minimize these events through regular assessments of our equipment and an ongoing review of our maintenance plans in order to balance our maintenance costs with optimal availability targets.

Our long-term target is to increase productivity and maintain availability at 88 to 90 per cent. In 2014, our adjusted availability was 90.5 per cent, up from 87.8 in 2013 due to lower unplanned outages at Canadian Coal. Over the last three years, our average adjusted availability has been 89.4 per cent, which is in line with our corporate target.

Our operations, maintenance, and administration ("OM&A") costs reflect the cost of operating our facilities. These costs can fluctuate due to the timing and nature of planned and unplanned 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. In our Wind fleet, at some of our Gas facilities, and at the Canadian Coal plants we operate, we have established long-term service agreements with third-party suppliers to reduce these costs, as well as maintenance-related sustaining capital costs. We measure our ability to maintain productivity based on the Generation Segment's comparable OM&A costs per produced MWh.

Comparable generation OM&A costs per produced MWh have decreased by three per cent per year over the last three years due to greater efficiency following the return to service of Sundance Units 1 and 2. Further improvements were achieved as a result of reduced maintenance costs associated with lower unplanned outages and the implementation of initiatives to reduce contract labour, staff overtime work, and material usage.

Comparable Generation OM&A *($/produced MWh)*



People

Our experienced leadership team has a broad mix of skills in the electricity sector, including in relation to 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 operational excellence, 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.

Significant 2014 Events and Subsequent Events

South Hedland Power Project

On July 28, 2014, we agreed to build, own, and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 million to build, including the cost of acquiring existing equipment from Horizon Power. The development has been fully contracted under 25-year Power Purchase Agreements with Horizon Power, a state-owned utility company, and The Pilbara Infrastructure Pty Ltd., a wholly owned subsidiary of Fortescue Metals Group ("FMG"), a mining company. The project may be expanded to accommodate additional customers at later dates. The power station will supply Horizon Power's customers in the Pilbara region as well as FMG's port operations. IHI Engineering Australia has been selected as the contractor to construct the power station. Relevant work and environmental permits have been received and construction commenced in January 2015. The power station is expected to be commissioned and delivering power to customers in the first half of 2017.

Australia Natural Gas Pipeline

On Jan. 15, 2014, we formed the Fortescue River Gas Pipeline Joint Venture to build, own, and operate an AUD$178 million, 270-kilometre natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station. Usage of the pipeline has been contracted to FMG to supply gas for the Solomon gas-fired facilities under a 20-year agreement. We hold a 43 per cent interest in the joint venture through a wholly owned subsidiary. The project is on schedule and within budget. Construction is being finalized and commercial operations are expected to begin in March 2015. In addition to our portion of the pipeline cost, AUD$14 million in plant retrofitting costs were incurred to allow the Solomon power station to burn gas instead of diesel, which will provide a return over time through increased lease payments. Full commissioning of the Solomon plant is expected to align with the start of the pipeline operations.

Sundance Unit 7

During 2014, TAMA Power continued to develop plans to build an 856 MW, highly efficient gas-fired power plant, Sundance Unit 7, in an area adjacent to our Canadian Coal operations. TAMA Power has secured a contract for primary equipment and is in the final stage of negotiations for other equipment. TAMA Power is also finalizing an arrangement with an engineering, procurement, and construction contractor. On Dec. 11, 2014, the AUC announced a public hearing, to proceed in 2015, on the proposed facility. TAMA Power expects to receive approval from the AUC in the first half of 2015.

Sale of Preferred Shares

On Aug. 15, 2014, we completed a public offering of 6.6 million Series G 5.3 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $165 million. The net proceeds from the offering were used for general corporate purposes, including repaying borrowings under existing credit facilities and funding 2015 debt maturities.

Sale of CE Gen, Blackrock, CalEnergy, and Wailuku

We completed the sale of our 50 per cent interest in CE Gen, Blackrock, and CalEnergy on June 12, 2014, and the sale of our 50 per cent interest in the Wailuku facility on Nov. 25, 2014, for total gross proceeds of U.S.$205.5 million. The net proceeds were U.S.$193.5 million, after consideration of an equity contribution that we made to CE Gen in May 2014. No significant gains or losses resulted from the sales. Proceeds have been used to repay amounts outstanding on our credit facilities.

Secondary Offering of TransAlta Renewables Shares

On April 29, 2014, we completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. As a result of the offering, we received gross proceeds of approximately $136 million (net proceeds of approximately $129 million after issuance costs). The net proceeds from the offering were used to reduce indebtedness. Following completion of the offering, we own approximately 70.3 per cent of the common shares of TransAlta Renewables.

Senior Notes Offering

On June 3, 2014, we completed an offering of U.S.$400 million of senior notes, due in June 2017, that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes. The net proceeds from the offering were used for general corporate purposes, including repaying borrowings under existing credit facilities and funding 2015 debt maturities.

Issuance of Bonds

On Feb. 11, 2015, the Corporation and its partner issued bonds secured by their jointly owned Pingston facility. Our share of gross proceeds was $45 million. The bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent. Excess proceeds, net of transaction costs, are to be used for general corporate purposes.

Major Maintenance Agreement

On Nov. 14, 2014, we entered into an agreement with Alstom to provide major maintenance for our Canadian Coal facilities. The agreement relates to 10 major maintenance projects over the next three years at our Keephills and Sundance plants. It also expands Alstom's current scope of work to service critical power assets, including boilers, steam turbines, generators, and other plant equipment. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

The new arrangement is expected to deliver an average 15 per cent cost reduction per turnaround and shorter turnaround times for major maintenance work, resulting in estimated direct cost savings of $34 million over the full term of the agreement.

Restructuring of Canadian Coal

On Jan. 14, 2015, we initiated a significant cost reduction initiative at our Canadian Coal operations to run a stronger and more competitive business. The restructuring results in the elimination of positions, providing anticipated full year annual savings of approximately $12 million. Costs associated with the initiative are expected to total $10 million.

Board of Directors Appointments

During the third quarter of 2014, we announced that Mr. P. Thomas Jenkins, OC, CD and Mr. John. P. Dielwart had been appointed to our Board of Directors (the "Board"), effective Sept. 1 and Oct. 1, 2014, respectively. The appointments are the result of our ongoing process of evaluating the skills and composition of the Board, planning for succession, and aligning the skills of the Board with the strategic direction of the Corporation.

Executive Leadership Team Appointments

On March 18, 2014, we announced three senior leadership appointments that will enhance our objectives of operational excellence from the base business and growth. Brett Gellner was appointed to the role of Chief Investment Officer, responsible for leading all growth aspects of the Corporation. Donald Tremblay joined TransAlta as Chief Financial Officer, effective March 31, 2014, and on July 3, 2014, Wayne Collins joined TransAlta as Executive Vice President, Coal and Mining Operations.

California Claim

On May 30, 2014, we announced that our settlement with California utilities, the California Attorney General, and certain other parties (the "California Parties") to resolve claims related to the 2000-2001 power crisis in the State of California had been approved by the U.S. Federal Energy Regulatory Commission. The settlement provides for the payment by us of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to us from accounts receivable. The first payment of U.S.$26 million was paid in June 2014 and the second is expected to be made in 2015. During the fourth quarter of 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to earnings of approximately $56 million. An additional pre-tax charge to 2014 second quarter earnings of $5 million arose as a result of the final settlement.

Proceedings before the Alberta Utilities Commission

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the AUC alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. TransAlta has denied the MSA's allegations in their entirety. An oral hearing before the AUC took place in December 2014. The next phase of the hearing, consisting of a written argument, is currently under way and will be completed by the end of February 2015. The AUC's decision on this matter is expected within 90 days after the written argument has completed. Presently, the outcome is not determinable.

Fort McMurray Transmission Project

During 2014, our strategic partnership with MidAmerican Transmission, TAMA Transmission LP ("TAMA Transmission"), qualified to bid to design, build, and operate the Fort McMurray West 500 kilovolt transmission project. In December 2014, after completing its review of all bid submissions, the AESO notified TAMA Transmission that the contract had been awarded to a competitor.

Discussion of Segmented Comparable Results

We have three business segments: Generation, Energy Marketing, and Corporate. Comparable figures are not defined under IFRS. Refer to the Earnings and Other Measures on a Comparable Basis section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Generation

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.

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 plant availability and production of electricity. Electricity sales generated by our commercial and industrial group in Alberta are assumed to be sourced from our Canadian Coal production within the Generation Segment.**

Canadian Coal

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**88.6**	80.9	85.7
Contract production *(GWh)*	**21,748**	17,789	16,924
Merchant production *(GWh)*	**3,806**	3,779	3,341
Total production *(GWh)*	**25,554**	21,568	20,265
Gross installed capacity *(MW)*	**3,771**	3,771	3,211
Revenues	**1,023**	916	913
Fuel and purchased power	**436**	393	342
Comparable gross margin	**587**	523	571
Operations, maintenance, and administration	**199**	205	198
Taxes, other than income taxes	**12**	11	10
Gain on sale of assets	**(1)**	(2)	(10)
Net other operating income	**(9)**	–	–
Comparable EBITDA	**386**	309	373
Depreciation and amortization	**292**	292	268
Other[1]	**–**	–	(20)
Comparable operating income	**94**	17	125
Sustaining capital:			
Routine capital	**56**	69	59
Mining capital	**45**	65	38
Finance leases	**10**	9	–
Planned major maintenance	**100**	94	219
Total	**211**	237	316

1 *Impacts to revenue associated with Sundance Units 1 and 2.*

2014

Production for the year ended Dec. 31, 2014 increased 3,986 GWh compared to 2013. Production for 2013 was impacted by a seven-month outage at our Keephills Unit 1 facility and the return to service of Sundance Units 1 and 2 in September and October, respectively.

For the year ended Dec. 31, 2014, comparable gross margin increased by $64 million compared to 2013, primarily as a result of lower unplanned outages, lower unit coal costs, and contract price escalations. Lower prices in Alberta in 2014 compared to 2013 decreased incentive payments received for generation in excess of PPA targets, offsetting some of the gain in reliability. We were able to achieve the reduction in coal costs after we took over operations at the Highvale mine in 2013.

OM&A for the year ended Dec. 31, 2014 decreased despite much higher operating capacity with Sundance Units 1 and 2 returning to service. We achieved a reduction in OM&A as a result of reduced maintenance costs associated with lower unplanned outages and the implementation of initiatives to reduce contract labour, staff overtime work, and material usage.

Other operating income resulted from the settlement of a dispute with a supplier in relation to an equipment failure in prior years.

Depreciation and amortization for the year ended Dec. 31, 2014 was consistent compared to 2013. The increase in depreciation and amortization that resulted from an increased asset base, primarily related to Sundance Units 1 and 2 returning to service, was offset by fewer asset retirements during the year and the life extension of certain components.

For the year ended Dec. 31, 2014, sustaining capital returned to a more normal level and decreased $26 million compared to 2013. Sustaining capital in 2013 was higher as a result of the Keephills Unit 1 force majeure and investments to increase mining intensity.

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 compared to 2012 is mainly due to the lower number of planned outages, offset by higher mining equipment purchases.

1 *Adjusted for economic dispatching.*

U.S. Coal

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**82.8**	78.3	81.8
Adjusted availability *(%)*[1]	**87.7**	91.9	90.8
Production *(GWh)*	**6,684**	6,711	3,736
Gross installed capacity *(MW)*	**1,340**	1,340	1,340
Revenues	**368**	346	368
Fuel and purchased power	**251**	227	169
Comparable gross margin	**117**	119	199
Operations, maintenance, and administration	**52**	49	46
Taxes, other than income taxes	**3**	4	6
Gain on sale of assets	**–**	–	(1)
Comparable EBITDA	**62**	66	148
Depreciation and amortization	**54**	56	66
Comparable operating income	**8**	10	82
Sustaining capital:			
Routine capital	**2**	6	10
Planned major maintenance	**10**	10	22
Total	**12**	16	32

2014

Production was stable in 2014 compared to 2013, as higher unplanned outages at U.S. Coal were offset by lower economic dispatching as certain months during the period had higher prices which made production more economic. In periods of low market prices, such as during spring runoff, it can be more economic for us to not produce power at U.S. Coal and purchase power in the market to satisfy our contractual obligations.

Comparable EBITDA decreased $4 million in 2014, as 2013 comparable EBITDA included the favourable effects of adjustments to commercial arrangements recognized in prior periods. The effect of prior year adjustments was partially offset by increased optimization margins earned, as we were able to capitalize on high market volatility early in the year. Our marketing and operations teams took advantage of this volatility by generating more power during periods of higher prices or reducing production and supplying from cheaper sources during periods of low prices to satisfy contracted sales.

In December 2014, we started supplying 280 MW under a long-term contract with Puget Sound Energy. The contract volumes escalate to 380 MW in December 2016. Hedge accounting was applied to this contract, with changes in value recorded in other comprehensive income ("OCI"). Hedge accounting could not be applied to certain other contracts, and accordingly, the mark-to-market on these contracts impacted reported earnings. The impacts of these mark-to-market fluctuations have been removed from revenues to arrive at comparable results, which reflect the economic nature of these contracts.

For the year ended Dec. 31, 2014, sustaining capital decreased by $4 million compared to 2013 primarily due to general equipment repair and replacement.

2013

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

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 compared to 2012 is mainly 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. Comparable results, availability, production, and capacity include assets under finance leases.

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**94.0**	94.5	93.6
Production *(GWh)*	**7,390**	7,854	8,230
Gross installed capacity *(MW)*	**1,531**	1,779	1,731
Revenues	**744**	683	626
Fuel and purchased power	**326**	252	226
Comparable gross margin	**418**	431	400
Operations, maintenance, and administration	**105**	102	87
Taxes, other than income taxes	**4**	3	4
Gain on sale of assets	**-**	-	(3)
Net other operating income	**-**	(1)	-
Comparable EBITDA	**309**	327	312
Depreciation and amortization	**114**	108	112
Comparable operating income	**195**	219	200
Sustaining capital:			
Routine capital	**24**	17	13
Planned major maintenance	**39**	41	36
Total	**63**	58	49

2014

Production for the year ended Dec. 31, 2014 decreased 464 GWh compared to 2013 due to the reduced requirement to run our Ottawa facility under the terms of its new capacity-based contract. The new contract is consistent with our contracting strategy and its 20-year duration supports continued investment in the facility.

Comparable EBITDA for the year ended Dec. 31, 2014 decreased by $18 million compared to 2013, primarily due to the impact of lower Alberta prices on our merchant capacity in the province and the reduced contribution from our Ottawa facility under the terms of the new contract. These decreases in comparable EBITDA were partially offset by the benefits achieved through resale of higher priced excess gas during unplanned outages in 2014. The current year results include an $8 million unrealized loss on forward purchase and physical gas volumes in Ontario, which is offset by unrealized gains of the same amount in the Energy Marketing Segment.

For the year ended Dec. 31, 2014, sustaining capital increased by $5 million compared to 2013 mainly due to compressor repairs at Mississauga.

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 $4 million compared to 2012 due to a decrease in asset retirements and favourable changes in foreign exchange rates.

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

Wind

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**94.6**	93.8	95.6
Production *(GWh)*	**3,175**	2,709	2,583
Gross installed capacity *(MW)*	**1,291**	1,289	1,145
Revenues	**247**	237	207
Fuel and purchased power	**14**	13	12
Comparable gross margin	**233**	224	195
Operations, maintenance, and administration	**50**	39	39
Taxes, other than income taxes	**6**	5	5
Comparable EBITDA	**177**	180	151
Depreciation and amortization	**88**	79	72
Comparable operating income	**89**	101	79
Sustaining capital:			
Routine capital	**2**	3	2
Planned major maintenance	**10**	6	2
Total	**12**	9	4

2014

Production for the year ended Dec. 31, 2014 increased 466 GWh compared to 2013, primarily due to the contribution from a full year of operations at Wyoming wind and New Richmond and higher wind volumes in Eastern Canada.

For the year ended Dec. 31, 2014, comparable EBITDA decreased by $3 million compared to 2013. Lower prices in Alberta in 2014 compared to 2013 more than offset the contribution of new wind projects commissioned or acquired in 2013.

Depreciation and amortization for the year ended Dec. 31, 2014 increased by $9 million compared to 2013, primarily due to the higher asset base associated with recently added facilities.

For the year ended Dec. 31, 2014, sustaining capital increased by $3 million compared to 2013 mainly due to an increase in planned major maintenance activities as a result of an outage at Le Nordais. All units at Le Nordais are now in operation.

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.

Hydro

Year ended Dec. 31	2014	2013	2012
Production *(GWh)*	**1,885**	2,085	2,356
Gross installed capacity *(MW)*	**913**	913	913
Revenues	**131**	181	164
Fuel and purchased power	**9**	5	7
Comparable gross margin	**122**	176	157
Operations, maintenance, and administration	**40**	32	28
Taxes, other than income taxes	**3**	3	2
Net other operating income	**(6)**	(6)	–
Comparable EBITDA	**85**	147	127
Depreciation and amortization	**24**	25	29
Comparable operating income	**61**	122	98
Sustaining capital:			
Routine capital	**9**	8	7
Planned major maintenance	**3**	5	7
Total before flood-recovery capital	**12**	13	14
Flood-recovery capital	**9**	1	–
Total	**21**	14	14

2014

Production for the year ended Dec. 31, 2014 decreased 200 GWh compared to 2013 due to lower water resource in Western Canada and optimization of storage capacity to capture highest prices.

Comparable EBITDA decreased by $62 million in 2014 compared to 2013, primarily as a result of lower prices and low price volatility in Alberta, which limited our ability to take advantage of our flexibility to produce electricity during higher priced hours.

Net other operating income relates to business interruption insurance proceeds paid in respect of prior period events.

For the year ended Dec. 31, 2014, sustaining capital increased by $7 million compared to 2013, mainly due to flood-recovery capital. These expenditures were mostly recovered through insurance proceeds recognized in net earnings in 2014, as non-comparable items.

2013

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

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 resource.

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.

Equity Investments

As outlined in the Significant 2014 Events and Subsequent Events section of this MD&A, we completed the sale of our interests in CE Gen and CalEnergy in June 2014 and Wailuku in November 2014.

The equity method was used to account for the results of the CE Gen, CalEnergy, and Wailuku joint ventures for the months of January and February 2014, but ceased effective March 1, 2014 with classification of these investments as assets held for sale in compliance with IFRS requirements. There were no earnings from Equity Investments during the two-month period (2013 annual – loss of $10 million, 2012 annual – loss of $15 million).

The table below summarizes key operational information adjusted to reflect our interest in these investments:

	Two months ended Feb. 28, 2014	Year ended Dec. 31, 2013	Year ended Dec. 31, 2012
Availability *(%)*	**97.1**	91.2	94.2
Production *(GWh)*:			
Gas	**127**	385	380
Renewables	**187**	1,170	1,200
Total production	**314**	1,555	1,580

Energy Marketing

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

Year ended Dec. 31	**2014**	2013	2012
Revenues and comparable gross margin	**108**	79	3
Operations, maintenance, and administration	**32**	18	16
Comparable EBITDA	**76**	61	(13)
Depreciation and amortization	**–**	1	–
Comparable operating income (loss)	**76**	60	(13)

2014

For the year ended Dec. 31, 2014, Energy Marketing comparable EBITDA increased by $15 million compared to 2013 due to extreme weather events that caused unprecedented gas and power commodity price volatility in eastern markets during the first and fourth quarters of 2014, which positively impacted our ability to optimize our portfolio of generation, transportation, transmission, and storage assets. We also capitalized on low risk arbitrage opportunities brought about by the extreme market volatility. As noted in the Gas subsection earlier, an offsetting gain has also been recorded in this segment against Gas generation losses. The increase was partially offset by higher corporate cost allocations and higher performance-based compensation costs driven by the strong results.

2013

For the year ended Dec. 31, 2013, Energy Marketing 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.

Corporate

Our Generation and Energy Marketing 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, aboriginal relations, internal audit, and other administrative support.

The expenses incurred by the Corporate Segment are as follows:

Year ended Dec. 31	**2014**	2013	2012
Operations, maintenance, and administration and taxes other than income taxes	**(59)**	(67)	(83)
Depreciation and amortization	**26**	23	20
Comparable operating loss	**(85)**	(90)	(103)
Sustaining capital:			
Routine capital	**23**	22	24

2014

For the year ended Dec. 31, 2014, OM&A expense decreased by $8 million compared to 2013, primarily due to a change in the way in which certain overhead cost allocations are made within the organization, partially offset by higher incentive compensation.

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, a continued focus on managing costs, and lower costs 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.

Other Consolidated Results

Asset Impairment Charges and Reversals

All impairment charges and reversals are reported in the Generation Segment. Impairment charges can be reversed in future periods if the forecasted cash flows of the impacted plants improve.

2014

U.S. Coal

As at Nov. 30, 2014, we identified the decrease in projected growth in Mid-Columbia power prices as an indicator that the U.S. Coal cash-generating unit ("CGU") could be impaired. The U.S. Coal CGU's carrying amount at that date, net of associated long-term liabilities, was $372 million. We estimated the fair value less costs of disposal of the CGU, utilizing our long-range forecast, and the following key assumptions:

Mid-Columbia annual average power prices	U.S.$31.00 to 52.00 per MWh
On-highway diesel fuel on coal shipments	U.S.$3.06 to 3.37 per gallon
Discount rates	5.1 to 6.2 per cent

The valuation is subject to measurement uncertainty based on those assumptions, and on inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement ("MoA") for coal transition established with the State of Washington. The valuation period extended to the assumed decommissioning of the asset, after its projected cessation of operation in its current form in 2025.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded. Any adverse change in assumptions, in isolation, would have resulted in an impairment charge being recorded. We continue to manage risks associated with the CGU through optimization of our operating activities and capital plan.

Centralia Gas

During 2014, we sold to external counterparties and transferred to other owned facilities for productive use, assets of the Centralia gas facility, which had been fully impaired and had remained idled since 2010. As a result of the transactions, we recognized impairment reversals of $5 million, and the plant's generating capacity has been removed from total TransAlta owned capacity.

2013

Alberta Merchant

As part of the annual impairment review and assessment process in 2013, the Corporation's Alberta plants with significant merchant capacity were considered one cash-generating unit (the "Alberta Merchant CGU"). 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 became part of the Alberta Merchant CGU were reversed. Please refer to Note 6 of our audited consolidated financial statements within this Annual Report for additional information.

Renewables

We recognized a total pre-tax impairment charge of $4 million related to three contracted Hydro assets. The assets were impaired primarily due to an increase in future capital and operating expenses that resulted from the completion of condition assessments.

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2014	2013	2012
Interest on debt	**238**	240	227
Interest income	**-**	-	(2)
Capitalized interest	**(3)**	(2)	(4)
Ineffectiveness on hedges	**-**	-	4
Interest on finance lease obligations	**1**	-	-
Accretion of provisions	**18**	18	17
Net interest expense	**254**	256	242

For the year ended Dec. 31, 2014, net interest expense decreased compared to 2013, primarily due to the approximate $500 million reduction in debt during the year and lower interest rates on debt that was refinanced. Higher interest expense due to strengthening of the U.S. dollar has partially offset these decreases.

In 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.

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	2014	2013	2012
Earnings (loss) before income taxes	**239**	(12)	(445)
Income attributable to non-controlling interests	**(49)**	(29)	(37)
Equity loss	**-**	10	15
Impacts associated with certain de-designated and economic hedges	**(54)**	103	72
Asset impairment charges (reversals)	**(6)**	(18)	324
Restructuring provision (reversal)	**-**	(3)	13
Gain on sale of assets	**(2)**	(12)	(3)
Gain on sale of collateral	**-**	-	(15)
Foreign exchange loss on California claim	**4**	-	-
Flood-related maintenance costs, net of insurance recovery	**1**	7	3
TAMA Transmission bid costs	**5**	-	-
Net other operating losses	**1**	109	254
Comparable earnings attributable to TransAlta shareholders subject to tax	**139**	155	181
Comparable income tax expense adjustments:			
Income tax (expense) recovery related to impacts associated with certain de-designated and economic hedges	**(19)**	36	25
Income tax expense related to asset impairment charges and reversals	**(1)**	(5)	(5)
Income tax (expense) recovery related to restructuring provision	**-**	(1)	3
Income tax (expense) recovery related to gain on sale of assets	**1**	(2)	(1)
Income tax recovery related to divestiture of investment	**35**	-	-
Income tax expense related to (gain on sale of) reserve on collateral	**-**	-	(4)
Income tax (expense) recovery related to writedown of deferred income tax assets	**5**	(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 foreign exchange loss on California claim	**1**	-	-
Income tax recovery related to flood-related maintenance costs, net of insurance recovery	**-**	2	1
Income tax recovery related to TAMA Transmission bid costs	**1**	-	-
Income tax recovery related to net other operating losses	**-**	27	65
Total comparable income tax expense adjustments	**23**	34	(84)
Income tax expense (recovery)	**7**	(8)	102
Comparable income tax expense	**30**	26	18
Comparable effective tax rate on earnings attributable to TransAlta shareholders *(%)*	**22**	22	(46)

The comparable income tax expense increased for the year ended Dec. 31, 2014 compared to 2013 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, offset by lower comparable earnings.

In 2013, the comparable income tax expense 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.

The comparable effective tax rate on earnings attributable to TransAlta shareholders increased for the year ended Dec. 31, 2014 compared to 2013 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.

In 2013, the comparable effective tax rate on earnings attributable to TransAlta shareholders 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 the positive resolution of certain tax contingency matters in the prior period.

During the year ended Dec. 31, 2014, we reversed a previous writedown of deferred income tax assets of $5 million. The reversal was based on changes to taxable and deductible temporary differences during 2014 that impact the net U.S. deferred income tax assets and our assessment of recognition.

During the year ended Dec. 31, 2013, we recognized a writedown of deferred income tax assets of $28 million (2012 – $169 million). The deferred income tax assets related mainly to the tax benefits of losses associated with our directly owned U.S. operations. We wrote these assets off as it was no longer considered probable that sufficient future taxable income would be available from our directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations.

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. Canadian Power Holdings Inc. owns the minority interest in TA Cogen. We also own 70.3 per cent (80.6 per cent in 2013) of TransAlta Renewables. TransAlta Renewables is a publicly traded company listed on the Toronto Stock Exchange under the symbol "RNW". It has interests in 1,283 MW of renewable assets. Since we own a controlling interest in TA Cogen 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 and TransAlta Renewables that we do not own. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen 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, 2014 increased $20 million to $49 million compared to 2013, primarily due to the formation of TransAlta Renewables and increased public ownership.

In 2013, earnings attributable to non-controlling interests decreased $8 million compared to 2012, due to lower earnings at TA Cogen.

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, 2014, 2013, and 2012. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

Earnings and Other Measures on a Comparable Basis

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.

In calculating these items, we exclude certain items 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.

During 2014, prior period restatements were made to 2013 and 2012. Refer to the Current Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable earnings for the year ended Dec. 31, 2014, 2013, and 2012 are as follows. References are to reconciliations presented on the following pages.

Year ended Dec. 31			**2014**	2013	2012
Reference number	**Adjustment**	**Segment and fuel type**			
Reclassifications:					
1	Finance lease income used as a proxy for operating revenue	Generation (Gas)	**49**	46	16
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Generation (Gas)	**3**	1	3
3	Reclassification of mine depreciation from fuel and purchased power	Generation (Canadian Coal)	**56**	58	41
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Generation (Canadian Coal)	**1**	2	10
		Generation (U.S. Coal)	**-**	-	1
		Generation (Gas)	**-**	-	3
5	Impacts to revenue associated with Sundance Units 1 and 2	Generation (Canadian Coal)	**-**	-	20
Adjustments (increasing (decreasing) earnings to arrive at comparable results):					
6	Impacts to revenue associated with certain de-designated and economic hedges	Generation (U.S. Coal)	**(54)**	103	72
7	Flood-related maintenance costs, net of insurance recoveries	Generation (Hydro)	**1**	7	-
8	Writeoff of Project Pioneer costs	Generation (Canadian Coal)	**-**	-	3
9	Costs related to TAMA Transmission bid	Corporate	**5**	-	-
10	Asset impairment charges (reversals)	Generation (Canadian Coal)	**-**	-	(41)
		Generation (U.S. Coal)	**-**	-	347
		Generation (Gas)	**(6)**	1	-
		Generation (Wind)	**-**	(23)	16
		Generation (Hydro)	**-**	4	2
11	Restructuring charges	Generation (Canadian Coal)	**-**	(2)	4
		Generation (Gas)	**-**	-	1
		Corporate	**-**	(1)	8
12	California claim	Energy Marketing	**5**	56	-
13	Non-comparable portion of insurance recovery received	Generation (Hydro)	**(4)**	(1)	-
14	Sundance Units 1 and 2 return to service	Generation (Canadian Coal)	**-**	25	254
15	Loss on assumption of pension obligation	Generation (Canadian Coal)	**-**	29	-
16	Foreign exchange on California claim	Unassigned	**4**	-	-
17	Non-comparable gain on sale of assets	Generation (Equity Investments)	**(2)**	-	-
		Corporate	**-**	(12)	-
		Generation (Wind)	**-**	-	(3)
18	Gain on sale of collateral	Energy Marketing	**-**	-	(15)
19	Writedown (reversal of writedown) of deferred income tax assets	Unassigned	**(5)**	28	169
20	Net tax effect of other comparable adjustments	Unassigned	**(18)**	(62)	(85)
21	Non-comparable item attributable to non-controlling interest	Unassigned	**1**	-	-

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2014 and 2013 is as follows:

Year ended Dec. 31	**2014**				2013			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**2,623**	**52**[1,2]	**(54)**[6]	**2,621**	2,292	47[1,2]	103[6]	2,442
Fuel and purchased power	**1,092**	**(56)**[3]	**-**	**1,036**	948	(58)[3]	-	890
Gross margin	**1,531**	**108**	**(54)**	**1,585**	1,344	105	103	1,552
Operations, maintenance, and administration	**542**	**-**	**(6)**[7,9]	**536**	516	-	(5)[7]	511
Asset impairment charges	**(6)**	**-**	**6**[10]	**-**	(18)	-	18[10]	-
Restructuring provision	**-**	**-**	**-**	**-**	(3)	-	3[11]	-
Taxes, other than income taxes	**29**	**-**	**-**	**29**	27	-	-	27
Gain on sale of assets	**-**	**(1)**[4]	**-**	**(1)**	-	(2)[4]	-	(2)
Net other operating (income) losses	**(14)**	**-**	**(1)**[12,13]	**(15)**	102	-	(109)[12,13,14,15]	(7)
Earnings before interest, taxes, depreciation, and amortization	**980**	**109**	**(53)**	**1,036**	720	107	196	1,023
Depreciation and amortization	**538**	**60**[2,3,4]	**-**	**598**	525	61[2,3,4]	(2)[7]	584
Operating income	**442**	**49**	**(53)**	**438**	195	46	198	439
Finance lease income	**49**	**(49)**[1]	**-**	**-**	46	(46)[1]	-	-
Equity loss	**-**	**-**	**-**	**-**	(10)	-	-	(10)
Foreign exchange gain (loss)	**-**	**-**	**4**[16]	**4**	1	-	-	1
Gain on sale of assets	**2**	**-**	**(2)**[17]	**-**	12	-	(12)[17]	-
Other income	**-**	**-**	**-**	**-**	-	-	-	-
Earnings (loss) before interest and taxes	**493**	**-**	**(51)**	**442**	244	-	186	430
Net interest expense	**254**	**-**	**-**	**254**	256	-	-	256
Income tax expense (recovery)	**7**	**-**	**23**[19,20]	**30**	(8)	-	34[19,20]	26
Net earnings (loss)	**232**	**-**	**(74)**	**158**	(4)	-	152	148
Non-controlling interests	**50**	**-**	**(1)**[21]	**49**	29	-	-	29
Net earnings (loss) attributable to TransAlta shareholders	**182**	**-**	**(73)**	**109**	(33)	-	152	119
Preferred share dividends	**41**	**-**	**-**	**41**	38	-	-	38
Net earnings (loss) attributable to common shareholders	**141**	**-**	**(73)**	**68**	(71)	-	152	81
Weighted average number of common shares outstanding in the year	**273**			**273**	264			264
Net earnings (loss) per share attributable to common shareholders	**0.52**			**0.25**	(0.27)			0.31

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2012 is as follows:

Year ended Dec. 31	2012			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,210	(1)[1,2,5]	72[6]	2,281
Fuel and purchased power	797	(41)[3]	–	756
Gross margin	1,413	40	72	1,525
Operations, maintenance, and administration	499	–	(3)[8]	496
Asset impairment charges	324	–	(324)[10]	–
Restructuring provision	13	–	(13)[11]	–
Taxes, other than income taxes	28	–	–	28
Gain on sale of assets	–	(14)[4]	–	(14)
Net other operating (income) losses	254	–	(254)[14]	–
Earnings before interest, taxes, depreciation, and amortization	295	54	666	1,015
Depreciation and amortization	509	58[2,3,4]	–	567
Other	–	(20)[5]	–	(20)
Operating income	(214)	16	666	468
Finance lease income	16	(16)[1]	–	–
Equity loss	(15)	–	–	(15)
Foreign exchange loss	(9)	–	–	(9)
Gain on sale of assets	3	–	(3)[17]	–
Gain on sale of collateral	15	–	(15)[18]	–
Other income	1	–	–	1
Earnings before interest and taxes	(203)	–	648	445
Net interest expense	242	–	–	242
Income tax expense	102	–	(84)[19,20]	18
Net earnings	(547)	–	732	185
Non-controlling interests	37	–	–	37
Net earnings attributable to TransAlta shareholders	(584)	–	732	148
Preferred share dividends	31	–	–	31
Net earnings attributable to common shareholders	(615)	–	732	117
Weighted average number of common shares outstanding in the year	235			235
Net earnings per share attributable to common shareholders	(2.62)			0.50

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. 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 Marketing segments in relation to commodity risk management activities, commodity hedging activities, and other contracting activities and (ii) those used in the hedging of interest rate and foreign currency exposures on debt, foreign currency exposures on projects and other 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. The financial instruments we enter into 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 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 property, plant, and equipment ("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.

Following the divestiture of CE Gen, Blackrock, and CalEnergy, and the repatriation of proceeds into Canadian funds, we de-designated approximately U.S.$180 million of debt from hedging U.S. net investments. During the third quarter of 2014, we de-designated an additional U.S.$90 million of U.S.-denominated debt hedging other U.S. operations. Prospectively, these tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

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 reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2014, Level III instruments had a net asset carrying value of $217 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, 2013.

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. Liquidity risk related to commodity risk management activities is managed by maintaining sufficient reserves and monitoring our counterparties and the markets in which we transact.

Our liquidity needs are met through a variety of sources, including cash generated from operations, availability 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 interests, and interest and principal payments on debt securities.

On Dec. 17, 2014, we filed a U.S. base shelf prospectus that allows for the issuance of up to U.S.$2.0 billion aggregate principal amount (or its equivalent in other currencies) of common shares, first preferred shares, warrants, subscription receipts, or debt securities from time to time. The specific terms of any offering of securities is to be determined at the date of issue.

Debt

Long-term debt totalled $4.0 billion as at Dec. 31, 2014 compared to $4.3 billion as at Dec. 31, 2013. Long-term debt decreased from Dec. 31, 2013 primarily due to the use of proceeds from the sale of CE Gen, Blackrock, and CalEnergy, the secondary offering of TransAlta Renewables common shares, and the issuance of preferred shares to pay down our credit facility borrowings. In May we repaid a $200 million maturing debenture by issuing a U.S.$400 million senior note. Excess proceeds were used to further reduce borrowings under our credit facilities.

During the year, strengthening of the U.S. dollar increased our long-term debt balances by $174 million. Almost all of our U.S.-denominated debt is hedged either through financial contracts or net investments in our U.S. operations. For 2014, the changes in our U.S.-denominated debt were offset as follows:

For the year ended Dec. 31	2014
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge)	55
Foreign currency cash flow hedges on debt	79
Effects of foreign exchange on value of U.S.-denominated Solomon finance lease	29
Other economic hedges	11
Total	**174**

Credit Facilities

At Dec. 31, 2014, we had a total of $2.1 billion (2013 – $2.1 billion) of committed credit facilities, of which $1.6 billion (2013 – $0.9 billion) was not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2014, the $0.5 billion (2013 – $1.2 billion) of credit utilized under these facilities was comprised of actual drawings of $0.1 billion (2013 – $0.8 billion) and letters of credit of $0.4 billion (2013 – $0.4 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2018, 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 2016. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $1.6 billion available under the credit facilities, we have $43 million of available cash.

Share Capital

On Feb. 18, 2015, we had 277.0 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G preferred shares outstanding. At Dec. 31, 2014, we had 275.0 million (2013 – 268.2 million) common shares issued and outstanding. At Dec. 31, 2014, we had 38.6 million (2013 – 32.0 million) first preferred shares issued and outstanding.

During the year ended Dec. 31, 2014, 6.8 million (2013 – 13.5 million) common shares were issued to shareholders that elected dividend reinvestment, for a total of $85 million (2013 – $186 million).

As noted in the Significant 2014 Events and Subsequent Events section of this MD&A, on Aug. 15, 2014, we completed a public offering of 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $165 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.325 per share as approved by the Board, payable quarterly, yielding 5.30 per cent per annum, for the initial period ending Sept. 30, 2019. The dividend rate will reset on Sept. 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.80 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series G preferred shareholders have the right at their option to convert their shares into Series H Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter. The holders of Series H preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill yield plus 3.80 per cent.

On Jan. 23, 2015, we declared a quarterly dividend of $0.18 per share on common shares, payable on April 1, 2015. This dividend is in line with the resized dividend that was announced in February 2014 of $0.72 per common share on an annualized basis. Declaration of dividends is at the discretion of the Board.

On Jan. 23, 2015, we declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2015.

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, commodity risk management and hedging activities, construction projects, and purchase obligations. At Dec. 31, 2014, we provided letters of credit totalling $396 million (2013 – $370 million) and cash collateral of $25 million (2013 – $21 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, 2014, the excess of current liabilities over current assets was $597 million (2013 – $116 million). The excess of current liabilities over current assets increased $481 million compared to 2013, primarily due to a U.S.$500 million senior note due in January 2015. The note was repaid using liquidity.

Capital Structure

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

	2014		2013	
As at Dec. 31	**Amount**	**%**	Amount	%
Net debt[1]	**3,917**	**50**	4,289	55
Non-controlling interests	**594**	**8**	517	7
Equity attributable to shareholders	**3,284**	**42**	2,906	38
Total capital	**7,795**	**100**	7,712	100

Commitments

Contractual commitments are as follows:

	Natural gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Non-cancellable operating leases	Coal supply and mining agreements	Long-term service agreements	Long-term debt[2]	Interest on long-term debt[3]	Growth	Total
2015	43	12	11	159	119	738	178	207	1,467
2016	29	9	10	137	120	29	171	50	555
2017	13	3	8	44	105	466	166	175	980
2018	12	4	8	45	33	878	129	8	1,117
2019	7	2	8	46	31	402	104	–	600
2020 and thereafter	101	6	54	605	172	1,472	723	–	3,133
Total	**205**	**36**	**99**	**1,036**	**580**	**3,985**	**1,471**	**440**	**7,852**

In November 2014, we entered into an agreement with Alstom to provide major maintenance for our operated Canadian Coal facilities. Please refer to the Significant 2014 Events and Subsequent Events section of this MD&A for more information.

As part of the TransAlta Energy Bill signed into law in the State of Washington and the subsequent MoA, we have committed to fund U.S.$55 million over the remaining life of the U.S. Coal plant to support economic and community 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 and certain circumstances, this funding or part thereof would no longer be required.

1 *Total debt and finance lease obligations net of cash and cash equivalents and fair value of related hedging instruments. Refer to Note 14 of our 2014 Notes to the Annual Financial Statements.*
2 *Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature in 2016, 2017, and 2018.*
3 *Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.*

Financial Position

The following chart outlines significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2013 to Dec. 31, 2014:

	Increase/ (decrease)	Primary factors explaining change
Trade and other receivables	**(54)**	Timing of customer receipts
Investments	**(192)**	Sale of CE Gen
Finance lease receivables (long-term)	**26**	Favourable changes in foreign exchange rates
Property, plant, and equipment, net	**45**	Additions and favourable changes in foreign exchange rates, partially offset by depreciation for the period
Deferred income tax assets	**(73)**	Changes in temporary differences
Risk management assets (current and long-term)[1]	**446**	Gains on long-term power sale contract and U.S. foreign currency hedges
Accounts payable and accrued liabilities	**34**	Higher capital accruals, partially offset by timing of payments and accruals
Dividends payable	**(30)**	Reduction of quarterly dividend
Long-term debt and finance lease obligations (including current portion)	**(291)**	Reduction of borrowings under credit facility and payout on maturity of medium-term notes, partially offset by the issuance of senior notes
Decommissioning and other provisions (current and long-term)	**24**	Fluctuations in period-end discount rates
Deferred income tax liabilities	**(25)**	Changes in temporary differences
Risk management liabilities (current and long-term)[1]	**34**	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	**378**	Net earnings for the period, gains on cash flow hedges recognized in other comprehensive income, and preferred shares issued, partially offset by declared dividends
Non-controlling interests	**77**	Sale of additional non-controlling interest in TransAlta Renewables, partially offset by non-controlling interests' portion of net earnings net of distributions

Statements of Cash Flows

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2014 and 2013:

Year ended Dec. 31	**2014**	2013	**Explanation of change**
Cash and cash equivalents, beginning of year	**42**	27	
Provided by (used in):			
Operating activities	**796**	765	Increase in cash earnings of $32 million. Refer to our discussion of funds from operations
Investing activities	**(292)**	(703)	Increase in proceeds on sale of investments of $224 million, a decrease in cash paid on the acquisition of Wyoming wind of $109 million, a decrease in additions to PP&E and intangibles of $72 million, and a decrease in investing non-cash working capital balances of $31 million, partially offset by a decrease in realized gains on financial instruments of $16 million and a decrease in proceeds on disposal of PP&E of $8 million
Financing activities	**(503)**	(47)	An increase in repayments of borrowings under credit facilities and in repayments (net of issuances) of long-term debt of $504 million, a decrease in proceeds on sale of non-controlling interest in subsidiary of $78 million, an increase in distributions paid to subsidiaries' non-controlling interests of $29 million, and an increase in common share cash dividends of $24 million, partially offset by an increase in proceeds on issuance of preferred shares of $161 million and an increase in realized gains on financial instruments of $20 million
Cash and cash equivalents, end of year	**43**	42	

1 *After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.*

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	

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 Highvale pension plans acquired in 2013, 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, 2014 for the Canadian pension plan, Jan. 1, 2014 for the U.S. pension plan, and Dec. 31, 2013 for the Highvale 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 for accounting purposes was conducted as at Dec. 31, 2013 for the Canadian plan and Jan. 1, 2014 for the U.S. plan.

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

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

Environmental issues and related legislation have, and will continue to have, an impact upon our business. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

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.

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.

Canadian Coal

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").

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 regulations provide additional operating time and increased flexibility for our Canadian Coal units, allowing those units to comply in a more cost-effective manner.

The release of the federal regulations creates 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 in an effort 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.

Other Canadian Developments

Since 2007, we have incurred costs as a result of GHG legislation in Alberta. On Dec. 19, 2014, the Alberta Government announced it was extending its current climate change legislation (the Specified Gas Emitters Regulation) until June 2015, with the stated intention of re-instituting a new program at that time. 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 that allow us the opportunity to recover capital and operating compliance costs from our PPA customers. The value realized from our environmental attributes generated in the province may also be impacted by the program's terms.

On Jan. 13, 2015, the Ontario Government announced its plan to put a price on carbon emissions in 2015, as part of its climate change program and stated objective of reducing GHG emissions by 15 per cent by 2020. No details are available yet. Our contracts at Gas facilities in the province generally include provisions protecting us from the adverse effects of changes in laws.

U.S. Coal

On June 2, 2014, the U.S. Environmental Protection Agency ("EPA") released draft regulations for managing GHG emissions from the power sector. These draft regulations target GHG emissions from all existing fossil-fired generation in the U.S.: coal, natural gas, and other hydrocarbon fuels. The draft regulations are designed to achieve a 30 per cent reduction from 2005 emission levels by 2030, for that sector. The proposed framework would establish 2030 emission rate goals, measured in pounds of carbon dioxide per MWh, for each state's electricity sector.

The draft regulations require interim goals to be achieved between 2020 and 2030 and a final goal to be achieved by 2030, and maintained beyond. The goals are state-specific depending on circumstances. States are to be given broad freedom to achieve the goals in a variety of ways, ranging from single- or multi-state cap and trade programs, heat rate improvements, and fuel switching initiatives, to more prescriptive approaches, such as, renewable energy and conservation programs. States will develop their individual approaches or State Implementation Plans, which will subsequently have to be reviewed and approved by the EPA. The draft regulations are expected to be finalized by the EPA by June 2015, with State Implementation Plans submitted by June 2016.

On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the State, where our U.S. Coal plant is located. Included in this program are a cap-and-trade plan and a low-carbon fuels standard. The proposed emissions cap will become more stringent over time, providing emitters time to transition their operations.

The recently proposed EPA GHG regulations for existing power plants are not expected to significantly affect our U.S. operations. TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State's climate change program. We believe that there will be no additional GHG regulatory burden on U.S. Coal given these commitments. The related TransAlta Energy Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation.

Other U.S. Developments

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

Australia

In Australia, the Government repealed the nation's carbon tax on July 17, 2014. This will eliminate the previous emission charges on our Australian gas-fired generation, although the impact is expected to be minimal as these emission charges were generally passed through to contracted customers. The Liberal Government has not yet implemented an alternative climate change program.

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 provides oversight to our environmental management programs and emission reduction initiatives to ensure continued compliance with environmental regulations.

In 2014, we estimate that 35.1 million tonnes of GHGs with an intensity of 0.91 tonnes per MWh (2013 – 27.5 million tonnes of GHGs with an intensity of 0.801 tonnes per MWh) were emitted as a result of normal operating activities.[1] The increased volume and intensity of GHG emissions in 2014 compared to 2013 is primarily due to higher Canadian Coal production, driven by reduced outages and Sundance Units 1 and 2 returning to service in the second half of 2013.

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 Canadian Coal operations in 2010 in order to meet Alberta's 70 per cent reduction objectives, and voluntarily at our U.S. 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.

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, oxygen combustion, biomass co-firing, and coal beneficiation.

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 *2014 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.*

2015 Financial Outlook

We expect comparable EBITDA for 2015 to be in the range of $1,000 million and $1,040 million based on the current outlook for power prices in Alberta and the Pacific Northwest. Comparable FFO is anticipated to be in the range of $720 to $770 million. Comparable free cash flow, excluding the effects of flood-recovery capital, is expected to be in the range of $265 million and $270 million, or $0.95 and $0.96 per share, based on sustaining capital, excluding the effects of flood-recovery capital, of approximately $310 million to $340 million. We anticipate that lower cash interest will be offset by higher distributions to non-controlling interest and preferred share dividends. Our expected dividend is 75 per cent to 76 per cent of comparable free cash flow.

Market

Power Prices

For 2015, power prices in Alberta are expected to be lower than 2014 as a result of increased supply, lower natural gas prices, and a risk to demand growth. However, prices can vary based on supply and weather conditions. In the Pacific Northwest and Ontario, we expect prices to settle lower than in 2014 due to lower natural gas prices.

Economic Environment

We expect growth to decelerate in Western Canada in 2015. The slowdown in the oil and gas sector is expected to reduce economic growth as a result of investment slowdown and lower consumer spending. After several years of weak growth, economic growth in the Pacific Northwest is expected to accelerate as the overall economic recovery in the U.S. gains strength. Growth in Ontario is expected to improve to moderate rates in 2015, driven largely by exports supported by U.S. recovery and the strengthening U.S. dollar.

We had no material counterparty losses in 2014. 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

Excluding the effects of economic dispatching, production is expected to increase in 2015 primarily due to lower planned and unplanned outages. Overall adjusted availability is expected to be in the range of 89 to 91 per cent in 2015, which is at the higher end of our long-term target availability.

We also expect to commission our gas pipeline to supply our Solomon facility in the first quarter of 2015.

Contracted Cash Flows

As a result of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 70 per cent of our capacity is contracted over the next seven years. 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 2014, approximately 88 per cent of our 2015 capacity was contracted. The average prices of our short-term physical and financial contracts for 2015 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 2015, on a standard cost per tonne basis, are expected to be similar to 2014 unit costs.

In the Pacific Northwest, our Centralia coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal is purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2015 is expected to increase by approximately one to two per cent as a result of inflation.

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.

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 Marketing
Earnings from our Energy Marketing Segment are affected by prices and volatility in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2015 objective for Energy Marketing is to contribute between $50 million to $70 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 foreign-denominated revenues.

Net Interest Expense
Net interest expense for 2015 is expected to be lower than in 2014 due to lower debt levels and higher capitalized interest. 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
We expect to maintain adequate available liquidity under our committed credit facilities.

Income Taxes
The effective tax rate on earnings, excluding non-comparable items for 2015, 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
Our major projects are focused on sustaining our current operations and supporting our growth strategy.

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

	Total Project		2015		
	Estimated spend	Spent to date[1]	Estimated spend	Target completion date	Details
Project					
South Hedland Power Station[2]	562	69	183	Q2 2017	150 MW combined cycle power plant
Australia natural gas pipeline[3]	100	77	23	Q1 2015	270 kilometre pipeline to supply natural gas to our Solomon power station in Western Australia
Transmission	13	2	11	Q2 2015	Regulated transmission that receives a return on investment
Hydro life extension	19	19	–	Q4 2014	Generator replacement and turbine runner improvements to extend the life of selected plants
Total	**694**	**167**	**217**		

Based on an assessment of the nature of prospective hydro life extension projects, beginning in 2015, the costs incurred for the hydro life extension are classified as sustaining capital.

1 *Represents amounts spent as of Dec. 31, 2014.*
2 *Estimated project spend is AUD$570 million. Total estimated project spend is stated in CAD$ and includes estimated capitalized interest costs. The total estimated project spend may change due to fluctuations in foreign exchange rates.*
3 *Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable. The total estimated project spend may change due to fluctuations in foreign exchange rates.*

Sustaining and Productivity Capital

A significant portion of our sustaining and productivity capital 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.

Our estimate for total sustaining and productivity capital is allocated among the following:

Category	Description	Spent in 2014	Expected spend in 2015
Routine capital[1]	Capital required to maintain our existing generating capacity	116	100-110
Planned major maintenance	Regularly scheduled major maintenance	162	180-190
Mining capital	Capital related to mining equipment and land purchases	45	20-25
Finance leases	Payments related to mining equipment under finance leases	10	10-15
Total sustaining capital excluding flood-recovery capital		**333**	**310-340**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	9	25-30
Total sustaining capital		**342**	**335-370**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	14	5-10
Total sustaining and productivity capital		**356**	**340-380**

We continue to anticipate that most flood-recovery capital expenditures will be recovered from third parties.

Lost production as a result of planned major maintenance, excluding U.S. Coal planned major maintenance which is scheduled during a period of economic dispatching, is estimated as follows for 2015:

	Coal	Gas and Renewables	Total
GWh lost	1,094-1,104	220-230	1,314-1,334

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, dividends reinvested, asset sales to TransAlta Renewables, 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.

1 *Does not include hydro life extension costs of $19 million in 2014. In 2015, includes estimated hydro life extension costs of $17 million.*

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 multilevel 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, examines 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 Chief Executive Officer and the Executive Vice-Presidents review key risks at least quarterly. Weekly or monthly specific Trading Risk Management meetings are held by the Vice-President Risk, Vice-President Trading, Executive Vice-President Energy Marketing, and Chief Financial Officer.

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 Officer and is comprised of the Chief Executive Officer, Chief Financial Officer, Chief Legal and Compliance Officer, Chief Investment Officer, and Executive Vice-President Corporate Services. 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 Risk Management Committee ("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 quarterly 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

Value at risk ("VaR") is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management 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 commodity risk management 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, 2014 associated with our proprietary commodity risk management activities was $5 million (2013 – $2 million). The increase is attributable to higher volatility levels around Dec. 31, 2014 than Dec. 31, 2013. 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.

For some risk factors we 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 2014. 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 and Wind 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 to the best of our ability and optimizing this resource against real-time electricity market opportunities,
- placing our wind facilities in locations that we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require, and
- diversifying our fuels and geography as one way of mitigating regional or fuel-specific events.

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

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

Generation Equipment and Technology Risk

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

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

During 2013, the original equipment manufacturer for the generators at Sundance Units 3 to 6 revised the operating criteria for the units such that they would 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 function and deliver power through transmission lines. More recently, equipment studies have been completed which have led to the original equipment manufacturer revising the capability curves such that the constraint for operations at high leading power factors has been relaxed. We are in the process of adjusting our plant settings to reflect the revised curves. We are also assessing compliance of uprated units with the AESO's proposed new MVAR standards.

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 2014, we had approximately 90 per cent (2013 – 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 2014, 68 per cent (2013 – 64 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2013 – 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings, assuming production consistent with 2014 and applying the contractual profile in place at Dec. 31, 2014 for 2015, are shown below:

Factor	Increase or decrease	Approximate impact on net earnings and cash flow
Electricity price – Canada	$1.00/MWh	3
Electricity price – U.S.	U.S.$1.00/MWh	2
Natural gas price	$0.10/GJ	1

Actual variations in net earnings can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability, and other factors.

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 U.S. Coal, 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 U.S. Coal 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 U.S. Coal 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 U.S. Coal,
- ensuring coal inventories on hand at Canadian Coal and U.S. Coal 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 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,
- investing in clean coal technology development, which potentially provides long-term promise for large emission reductions from fossil-fuel-fired generation, and
- incorporating change in law provisions in contracts that allow recovery of certain compliance costs from our customers.

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 Environment 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, 2013. We had no material counterparty losses in 2014, 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 commodity risk management 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 commodity risk management and hedging activities at Dec. 31, 2014 is provided below:

Counterparty credit rating	Net exposure amount
Investment grade	718
Non-investment grade	2
No external rating, internally rated as investment grade	23
No external rating, internally rated as non-investment grade	4

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions, is $29 million (2013 – $23 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. 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, 2014, we have hedged approximately 95 per cent (2013 – 99 per cent) of our foreign currency net investment exposure, which we define to exclude net U.S. risk management assets,
- 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 four cent increase or decrease in the U.S. 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	$0.04	2

Creditworthiness and Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for commodity risk management activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade credit 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 strengthening our financial position and maintaining stable investment grade credit ratings as our ability to efficiently access capital markets funding on a cost-effective basis is partially dependent upon the maintenance of satisfactory credit ratings. There can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, potentially resulting in adverse consequences for funding capacity, liquidity and access to capital markets. Changes in credit ratings may also affect the ability and/or the cost of establishing normal course derivative or hedging transactions undertaken by our Energy Marketing Segment. Credit ratings do not consider market price or address the suitability of any financial instrument for a particular investor and are not recommendations to purchase, sell or hold securities. Credit ratings are subject to revision or withdrawal at any time by the rating organization. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlook, are set out in the Strategy and Capability to Deliver Results – Financial Strategy section of this MD&A.

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 commodity risk management 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, 2014, approximately four per cent (2013 – 21 per cent) of our total debt portfolio was subject to changes 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[1]
Interest rate	0.25	–

Project Management Risk

On capital 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 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.

1 *A 0.25 per cent change in interest rates applied to our variable rate debt would not result in a material impact on net earnings. Based on our variable rate debt at Dec. 31, 2014, a 0.75 per cent change in interest rates would be required to have a $1 million impact on net earnings.*

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 2014, 54 per cent (2013 – 54 per cent) of our labour force was covered by 12 (2013 – 12) collective bargaining agreements. In 2014, four (2013 – five) agreements were renegotiated. We anticipate the successful negotiation of three collective agreements in 2015.

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 programs, which are reviewed periodically to ensure its effectiveness, as well as through our Government Relations team. 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 and liquidity risk, and counterparty risk.

Income Taxes

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

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	2

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2014 was 21 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. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

Critical Accounting Policies and Estimates

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

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

Our significant accounting policies are described in Note 2 to 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 commodity risk management 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.

Commodity risk management activities involve the use of 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 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 instruments that remain open at the end of a reporting period 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 commodity risk management 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 price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments 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. Our commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

Level III

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

We may enter into commodity transactions 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 commodity risk management 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 commodity risk management fair values are determined at Dec. 31, 2014 is estimated to be a +/- $120 million (2013 +/- $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/- $92 million (2013 +/- $87 million) in the stress value stems from a long-dated power sale contract that is designated as a cash flow hedge, while the remaining +/- $28 million (2013 +/- $18 million) accounts for the rest of the portfolio. The variable 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, 2014, PP&E makes up 74 per cent of our assets, of which 99 per cent relates to the Generation Segment. At the end of each reporting period, we assess whether there is any indication that a PP&E asset is impaired. Impairment exists when the carrying amount of the asset or CGU to which it belongs exceeds its recoverable amount, which is the higher of fair value less costs of disposal and value in use.

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 operations, 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 of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal 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 and outflows over the life of the facilities, 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 facilities. Appropriate discount rates reflecting the risks specific to the asset under review are used in the assessments. 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 2014 and other specific events, net pre-tax asset impairment reversals of $6 million (2013 – reversals of $18 million) were recorded related to certain facilities. Also, an impairment indicator was identified at our U.S. Coal CGU, but the estimated recoverable amount approximated its carrying amount. Refer to the Asset Impairment Charges and Reversals section of this MD&A for further details.

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 capitalization of these costs is evaluated each reporting period, and amounts capitalized 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 2014, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $595 million (2013 – $585 million), of which $56 million (2013 – $58 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 or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill arose on the acquisitions of the Wyoming wind farm, Canadian Hydro Developers, Inc., Merchant Energy Group of the Americas, Inc., and Vision Quest Windelectric Inc. As at Dec. 31, 2014, this goodwill had a total carrying amount of $462 million (2013 – $460 million).

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs or groups of 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 or group of 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 or groups of 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 either 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 $45 million (2013 – $118 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2014. 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 $434 million (2013 – $459 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2014. 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.

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 or site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. 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, 2014, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $305 million (2013 – $270 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 2015 and 2072. The majority of these costs will be incurred between 2020 and 2050. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	3
Undiscounted decommissioning and restoration provision	10	2

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

Inception Gains and Losses

We restated the Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Consolidated Statement of Financial Position were immaterial. Refer to Note 13(C) in our audited consolidated financial statements as at and for the year ended Dec. 31, 2014 for further information on inception gains and losses.

Inventory Writedown

During the third quarter of 2014, we restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as stand-alone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the years ended Dec. 31, 2013 and 2012 increased by $22 million and $44 million, respectively. The inventory writedown for the year ended Dec. 31, 2014 was $19 million.

Other Net Operating Income and Losses

We restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify the losses associated with the California claim, the Sundance Units 1 and 2 return to service, and the assumption of pension obligations, as well as gains from insurance recoveries, as a net other operating income and losses group within operating income. Previously, each item was presented in earnings outside of operating income. We initiated the change as part of our ongoing monitoring of additional IFRS measures. As a result of the change, operating income (loss) for the years ended Dec. 31, 2013 and 2012 decreased by $102 million and $254 million, respectively.

Energy Marketing Intersegment Cost Allocation

A portion of OM&A costs incurred in the Energy Marketing Segment and the Corporate Segment are allocated to other segments based on an estimate of operating expenses and a percentage of resources dedicated to providing support and services. Segment OM&A costs are comprised of expenses net of intersegment allocations. In prior years, the Energy Marketing intersegment charge and recovery was presented as a distinct line item as a component of operating income (loss). Comparative figures have been reclassified to conform to the current year's presentation.

IAS 32 Financial Instruments: Presentation

On Jan. 1, 2014, we adopted the amendments to IAS 32 *Financial Instruments: Presentation* regarding offsetting financial assets and financial liabilities. There was no impact of adopting the IAS 32 amendments on the audited consolidated financial statements.

IAS 36 Impairment of Assets

On Jan. 1, 2014, we adopted the amended disclosure requirements of IAS 36 *Impairment of Assets*. The amended disclosure requirements did not have an impact on the audited consolidated financial statements.

Comparative Figures

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

Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation include:

IFRS 9 Financial Instruments

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model.

Under the classification and measurement requirements for financial assets, financials 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.

The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities 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.

The new general hedge accounting model is intended to be simpler and more closely focus on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness.

The new requirements for impairment of financial assets introduce an expected loss impairment model that requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

Fourth Quarter

Consolidated Highlights

Three months ended Dec. 31	2014	2013
Revenues	**718**	587
Comparable EBITDA[1]	**301**	242
Net earnings (loss) attributable to common shareholders	**148**	(66)
Comparable net earnings attributable to common shareholders[1]	**46**	1
Comparable funds from operations[1]	**225**	179
Cash flow from operating activities	**250**	165
Comparable free cash flow[1]	**104**	61
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.54**	(0.25)
Comparable net earnings per share[1]	**0.17**	0.00
Comparable funds from operations per share[1]	**0.82**	0.67
Comparable free cash flow per share[1]	**0.38**	0.23
Dividends paid per common share	**0.18**	0.29

Financial Highlights

- Comparable EBITDA for the fourth quarter of 2014 increased by $59 million to $301 million compared to the same period in 2013, primarily due to strong availability throughout our generation portfolio, continued improved operational performance at Canadian Coal, lower coal cost at Canadian Coal, and improved year-over-year margins. Lower prices in Alberta negatively impacted revenue from generation in excess of targets at coal PPA facilities as well as revenue from our Wind portfolio in the province. Prices in Alberta averaged $30 per MWh during the fourth quarter of 2014, compared to $49 per MWh in the same period in 2013. Our strategy of being highly contracted and high availability in Canadian Coal generally limited the impacts of lower prices in Alberta.
- Higher comparable EBITDA translated into higher comparable FFO for the three months ended Dec. 31, 2014 of $225 million, exceeding comparable FFO for the same period last year by $46 million.
- Fourth quarter comparable net earnings attributable to common shareholders was $46 million ($0.17 net earnings per share), up from comparable net earnings of $1 million (nil net earnings per share), due to the increase in comparable EBITDA, partially offset by higher income tax expense.
- Reported net earnings attributable to common shareholders was $148 million for the fourth quarter ($0.54 net earnings per share) compared to a net loss of $66 million ($0.25 net loss per share) for the same period in 2013. The differences between comparable and reported net earnings are mainly due to increases in the fair value of de-designated and economic hedges at U.S. Coal and the effects of the California claim in 2013.

1 These 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 Comparable Funds from Operations and Comparable Free Cash Flow and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

Operational Results

Three months ended Dec. 31	2014	2013
Availability (%)[1]	93.2	91.8
Adjusted availability (%)[1]	93.2	91.8
Production (GWh)[1]	12,207	12,640
Comparable EBITDA		
Generation Segment		
Canadian Coal	118	68
U.S. Coal	19	14
Gas	81	82
Wind	56	58
Hydro	20	21
Total Generation Segment	294	243
Energy Marketing Segment	26	20
Corporate Segment	(19)	(21)
Total comparable EBITDA	301	242

- **Canadian Coal**: Comparable EBITDA increased $50 million to $118 million in the fourth quarter of 2014 compared to the same period in 2013, primarily as a result of lower coal costs following integration of the Highvale mine in 2013 and continued improved operational performance. Lower market-based incentive rates in connection with lower prices have offset some of the improvement. The 2014 comparable EBITDA also includes a gain on settlement of a dispute with a supplier in relation to an equipment failure in prior years.
- **U.S. Coal**: Comparable EBITDA was $19 million in the fourth quarter compared to $14 million for the same period in 2013. The increase in comparable EBITDA is primarily due to increased margins as we further optimized real-time operations against the spot market and fixed-price contracts. We have also started delivering power to Puget Sound Energy under a long-term fixed price contract in December 2014.
- **Gas**: Comparable EBITDA was consistent in the fourth quarter with the same period in 2013, despite lower Alberta prices, as gains from lower outages and contract adjustments were offset by a mark-to-market loss on gas.
- **Wind**: Comparable EBITDA decreased slightly in the fourth quarter to $56 million compared to $58 million for the same period in 2013. Production from our Wyoming facility has offset the effects of lower Alberta prices.
- **Hydro**: Comparable EBITDA was consistent in the fourth quarter with the same period in 2013, as most production was contract-based in both periods, and both periods included an insurance recovery for prior business interruption claims in similar amounts.
- **Energy Marketing Segment**: Energy Marketing generated income of $26 million in the fourth quarter, up $6 million compared to the fourth quarter of 2013 due to customer margin growth, our ability to capture arbitrage opportunities stemming from high volatility, particularly in Eastern markets, and offsetting intersegment gains to the Gas generation positions. The increase was partially offset by higher corporate cost allocations and higher performance-based compensation costs driven by the strong trading results.
- **Corporate Segment**: Our Corporate Segment incurred similar costs in the fourth quarter of 2014 of $19 million compared to $21 million in 2013. The lower costs resulted from reductions to external costs partially offset by higher incentive-based compensation and increased development costs.

1 *Availability includes assets under generation operations and finance leases and excludes Hydro assets and Equity Investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.*

Availability and Production

Availability for the three months ended Dec. 31, 2014 increased compared to the same period in 2013, primarily due to lower unplanned outages at Canadian Coal.

Lower production for the three months ended Dec. 31, 2014 compared to the same period in 2013 is primarily due to market curtailments at Centralia, partially offset by lower unplanned outages at Canadian Coal.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO per share and comparable free cash flow per share are calculated as follows using the weighted average number of common shares outstanding during the period.

Three months ended Dec. 31	2014	2013
Cash flow from operating activities	**250**	165
Change in non-cash operating working capital balances	**(23)**	(13)
Cash flow from operations before changes in working capital	**227**	152
Impacts associated with California claim	**-**	27
TAMA Transmission bid costs	**5**	-
Other non-comparable items	**(7)**	-
Comparable FFO	**225**	179
Deduct:		
Sustaining capital	**(87)**	(96)
Dividends paid on preferred shares	**(13)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(21)**	(12)
Comparable free cash flow	**104**	61
Weighted average number of common shares outstanding in the period	**275**	268
Comparable FFO per share	**0.82**	0.67
Comparable free cash flow per share	**0.38**	0.23

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Three months ended Dec. 31	2014	2013
Comparable EBITDA	**301**	242
Unrealized (losses) gains from risk management activities	**(12)**	(11)
Interest expense	**(58)**	(61)
Provisions	**-**	1
Current income tax expense	**(9)**	(3)
Realized foreign exchange gain (loss)	**14**	(3)
Decommissioning and restoration costs settled	**(5)**	(5)
Gain on sale of assets	**-**	2
Other non-cash items	**(6)**	17
Comparable FFO	**225**	179

Comparable FFO for the three months ended Dec. 31, 2014 increased $46 million to $225 million, compared to the same period in 2013, primarily due to higher comparable EBITDA.

Comparable free cash flow for the three months ended Dec. 31, 2014 increased $43 million to $104 million compared to the same period in 2013, primarily due to the increase in comparable FFO and a decrease in sustaining capital, partially offset by higher distributions paid to our subsidiaries' non-controlling interests as a result of the reduction of our interest in TransAlta Renewables and improved performance at TA Cogen.

Earnings on a Comparable Basis

During 2014, prior period restatements were made to 2013. Refer to the Current Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable earnings for the three months ended Dec. 31, 2014 and 2013 are as follows. References are to the subsequent reconciliation table.

Three months ended Dec. 31			2014	2013
Reference number	Adjustment	Segment and fuel type		
Reclassifications:				
1	Finance lease income used as a proxy for operating revenue	Generation (Gas)	**13**	12
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Generation (Gas)	**1**	–
3	Reclassification of mine depreciation from fuel and purchased power	Generation (Canadian Coal)	**15**	16
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Generation (Canadian Coal)	**1**	1
Adjustments (increasing (decreasing) earnings to arrive at comparable results):				
5	Impacts to revenue associated with certain de-designated and economic hedges	Generation (U.S. Coal)	**(47)**	43
6	Flood-related maintenance costs, net of insurance recoveries	Generation (Hydro)	**(5)**	2
7	Costs related to TAMA Transmission bid	Corporate	**5**	–
8	Asset impairment charges (reversals)	Generation (Gas)	**(5)**	–
9	Non-comparable portion of insurance recovery received	Generation (Hydro)	**(3)**	(1)
10	California claim	Energy Marketing	**-**	56
11	Sundance Units 1 and 2 return to service	Generation (Canadian Coal)	**-**	10
12	Foreign exchange on California claim	Unassigned	**2**	–
13	Non-comparable gain on sale of assets	Generation (Equity Investments)	**(1)**	–
		Corporate	**-**	(2)
14	Writedown (reversal) of deferred income tax assets	Unassigned	**(68)**	(12)
15	Net tax effect of all comparable adjustments	Unassigned	**20**	(29)

A reconciliation of comparable results to reported results for the three months ended Dec. 31, 2014 and 2013 is as follows:

	Three months ended Dec. 31, 2014				Three months ended Dec. 31, 2013			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**718**	**14**[1,2]	**(47)**[5]	**685**	587	12[1]	43[5]	642
Fuel and purchased power	**268**	**(15)**[3]	**–**	**253**	279	(16)[3]	–	263
Gross margin	**450**	**29**	**(47)**	**432**	308	28	43	379
Operations, maintenance, and administration	**138**	**–**	**–**[6,7]	**138**	140	–	–	140
Asset impairment charges (reversals)	**(5)**	**–**	**5**[8]	**–**	–	–	–	–
Taxes, other than income taxes	**8**	**–**	**–**	**8**	5	–	–	5
Gain on sale of assets	**–**	**(1)**[4]	**–**	**(1)**	–	(1)[4]	–	(1)
Net other operating (income) losses	**(17)**	**–**	**3**[9]	**(14)**	58	–	(65)[9,10,11]	(7)
EBITDA	**326**	**30**	**(55)**	**301**	105	29	108	242
Depreciation and amortization	**136**	**17**[2,34]	**–**	**153**	143	17[3,4]	(2)[6]	158
Operating income	**190**	**13**	**(55)**	**148**	(38)	12	110	84
Finance lease income	**13**	**(13)**[1]	**–**	**–**	12	(12)[1]	–	–
Equity income	**–**	**–**	**–**	**–**	(5)	–	–	(5)
Foreign exchange gain (loss)	**7**	**–**	**2**[12]	**9**	3	–	–	3
Gain on sale of assets	**1**	**–**	**(1)**[13]	**–**	2	–	(2)[13]	–
Earnings before interest and taxes	**211**	**–**	**(54)**	**157**	(26)	–	108	82
Net interest expense	**62**	**–**	**–**	**62**	66	–	–	66
Income tax expense (recovery)	**(26)**	**–**	**48**[14,15]	**22**	(49)	–	41[14,15]	(8)
Net earnings (loss)	**175**	**–**	**(102)**	**73**	(43)	–	67	24
Non-controlling interests	**14**	**–**	**–**	**14**	13	–	–	13
Net earnings (loss) attributable to TransAlta shareholders	**161**	**–**	**(102)**	**59**	(56)	–	67	11
Preferred share dividends	**13**	**–**	**–**	**13**	10	–	–	10
Net earnings (loss) attributable to common shareholders	**148**	**–**	**(102)**	**46**	(66)	–	67	1
Weighted average number of common shares outstanding in the period	**275**			**275**	268			268
Net earnings (loss) per share attributable to common shareholders	**0.54**			**0.17**	(0.25)			0.00

Selected Quarterly Information

	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Revenue	**775**	**491**	**639**	**718**
Comparable EBITDA	**310**	**213**	**212**	**301**
Comparable FFO	**238**	**154**	**145**	**225**
Comparable net earnings (loss) attributable to common shareholders	**47**	**(12)**	**(13)**	**46**
Net earnings (loss) attributable to common shareholders	**49**	**(50)**	**(6)**	**148**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	**(0.18)**	**(0.03)**	**0.54**
Comparable net earnings (loss) per share, basic and diluted	**0.17**	**(0.04)**	**(0.05)**	**0.17**

	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Revenue	540	542	623	587
Comparable EBITDA	268	247	266	242
Comparable FFO	193	184	174	179
Comparable net earnings attributable to common shareholders	32	9	39	1
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 net earnings per share, basic and diluted	0.12	0.03	0.15	0.00

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

Comparable net earnings is generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate. The second and third quarters of 2013 benefitted from high Alberta prices, offsetting some of the impacts of unplanned outages at Canadian Coal during the periods. In 2014, Canadian Coal improved its operational performance, with the third and fourth quarters also including reductions in coal costs. Some of these gains compared to the same periods in the previous year were offset by a downward trend in Alberta prices, starting from the second quarter of 2013. Market volatility can also impact quarterly contributions from our Energy Marketing Segment, as the first quarter of 2014 benefitted from exceptional weather conditions in northeastern North America, with the subsequent two quarters seeing muted volatility and reduced contribution from the Segment. Following public offerings of TransAlta Renewables common shares in the third quarter of 2013 and the second quarter of 2014, an increasing portion of earnings is attributable to non-controlling interests.

Revenue is impacted by market and operational factors listed above, and by changes in future power prices in the Pacific Northwest, which cause de-designated and economic hedges in the region to fluctuate in value. These hedges significantly depreciated in the first and fourth quarters of 2013, as well as the second quarter of 2014 and significantly increased in value over the second half of 2014.

Net earnings attributable to common shareholders have also been impacted by the following events:

- loss on assumption of pension obligation, in the first quarter of 2013;
- writedown of deferred tax assets, in the third quarter of 2013;
- loss associated with the California claim, in the fourth quarter of 2013.

Amounts per share reflect these fluctuations, with limited increases in the number of shares outstanding over the last eight quarters.

Disclosure 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, 2014, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Glossary of Key Terms

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

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

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

Biomass Co-Firing
When used as a supplemental fuel in an existing coal-fired boiler, biomass can provide the following benefits: lower fuel costs, more fuel flexibility, reduced waste to landfills, and reductions in sulfur oxide, nitrogen oxide, and carbon dioxide emissions.

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

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

Coal Beneficiation
Beneficiation of coal by reducing ash and/or moisture is found to improve the efficiency of power plant boilers, increase plant capacity factors and reduce the greenhouse gas emissions from power plants.

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

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

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

Expected Capacity
Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

Flue Gas Desulphurization Unit (Scrubber)
Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

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

Gasification
Reacting raw material, such as coal, at high temperatures with a controlled amount of oxygen and steam. Carbon dioxide can be removed from the resulting syngas fuel.

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW)
A measure of electric power equal to 1,000 megawatts.

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

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

Heat Rate
A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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

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

Merchant Assets
TransAlta uses the term merchant to describe assets that have contracts with terms of less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short and medium-term contracts.

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

Oxygen Combustion
Based on the principle that if coal burns in an environment where nitrogen is absent or minimized, the resulting carbon dioxide will be more concentrated and therefore easier to capture.

Renewable Power
Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Reserve Margin
An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Spark Spread
A measure of gross margin per MW (sales price less cost of natural gas).

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

Turbine
A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround
Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage
The shutdown of a generating unit due to an unanticipated breakdown.

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

Value at Risk (VaR)
A measure used to manage exposure to market risk from commodity risk management activities.