TransAlta

Powering Economies and Communities

TransAlta Corporation

2018 Annual Integrated Report

Letter to Shareholders

As I sit down to write this letter, we are halfway through our transformation to become a leading clean energy company. For the past 65 years, TransAlta has focused primarily on the development, construction and operation of coal-fired generating plants, fueling the growth of the communities where we operate. Almost 20 years ago, the Alberta electricity market was de-regulated and long-term power purchase arrangements (PPAs) were established. Today, we stand three years into our transformation that includes converting our Alberta coal units to gas generation in response to a competitive environment in Alberta that is defined by the PPAs coming to an end, the cost of carbon becoming a reality and the anticipated capacity market being implemented in Alberta. Our coal-to-gas conversions will be completed in another three to four years, at which time we will be a largely transformed business. Our strategy is based on both the need to respond to these external changes and our focus on realizing significant long-term value for our shareholders.

Our strategy is simple: i) convert to gas; ii) realize the full value of our hydro assets; and iii) grow TransAlta Renewables. The execution steps to make this strategy a reality are known, in place and tracking.

1. The first priority of our strategy involves shifting our Alberta fleet to compete in the capacity market, primarily by transitioning the coal fleet to gas in the 2020 to 2023 time frame. Once completed, we will see our Alberta thermal fleet contribute strong cash flow to the company for many years to come.

2. Our second priority is to maintain our Alberta hydro assets as we approach the expiry of its PPA. When this arrangement expires at the end of 2020, we expect to receive the full benefit of the attributes inherent in these hydro assets, including capacity, energy and ancillary services.

3. Our third strategic priority is to support growth in TransAlta Renewables. We receive a reliable dividend from our investment in TransAlta Renewables and this investment also extends our average contract life and reduces the business risk and cost of capital for TransAlta Corporation.

With the benefit of understanding our strategic priorities, let me now outline our performance in 2018 and what is to come in 2019 and beyond.

2018 Performance Highlights
In 2018, we realized some of our best performance for safety, availability and free cash flow:

- We delivered free cash flow of $367 million, $56 million higher than 2017, after adjusting for the one-time payment for the termination of the Sundance B and C power purchase arrangements in 2018 and the payment from the Ontario Electricity Financial Corporation in 2017 (net of our partner's share).
- Our total injuries declined 44% relative to 2017. While this is a great result, we are still striving to see further improvement.
- We increased our co-firing at the Canadian coal unit, resulting in savings of approximately $12 million in greenhouse gas costs.
- Availability was strong and we achieved our best availability at Sundance since 1990 and at Keephills since 2011.
- We increased cash flow from Australia from $127 million to $136 million.
- The hydro segment increased cash flow by $35 million, despite lower production, representing stronger energy pricing and the higher demand for ancillary services.
- We continued to pay down debt in 2018 with a reduction of net recourse debt of approximately $515 million. We expect to continue our deleveraging strategy over the next three years as part of our balanced capital allocation plan.

The successes of 2018 were hard-won given the headwinds of 2018:

- The net loss realized in 2018 was a result of, in part, the acceleration of the depreciation and amortization of the mine and coal assets provided by of the Off-Coal Agreement with the Government of Alberta.
- Carbon compliance costs increased due to regulated increase in the carbon price and the fact that carbon costs are no longer passed-through to the buyer under the power purchase arrangements.
- We retired Sundance Units 1 and 2 and mothballed Sundance Units 3 and 5, resulting in production at Canadian coal decreasing by over 8,000 gigawatts/hour compared to 2017.
- We realized higher coal costs on a dollar per MWh basis due to lower coal tonnage and the allocation of fixed costs across lower production - we are focused on providing the lowest cost fuel for the remaining life of the facilities.

TransAlta's performance in 2018 is particularly noteworthy given the work being undertaken to shift our cost structure and operating models to adapt to the new market and regulatory realities. This has been largely driven through our company-wide initiative known as Project Greenlight, which has produced meaningful change within the company. This includes adopting cost reduction measures, implementing operational improvements and enhancing employee engagement. Examples of this transformation include the headcount reduction of over 15% in 2018, the co-firing of gas at Sundance and Keephills, and improving equipment utilization at our mining operations. We are also focused on improving organizational effectiveness, which includes being operationally disciplined, encouraging bottom-up innovation and facilitating performance transparency. For a company that is over 100 years old, these changes do not come easily, but the success of this program to date is an indication of the company's commitment to drive value for decades to come.

Executing on Growth

When I think of our overall growth plans, I think about them in two categories. The growth in TransAlta Renewables and the growth represented by the coal-to-gas conversions in TransAlta.

Supporting Growth in TransAlta Renewables

In 2018, we entered into agreements providing for the development and construction of two new wind facilities: i) a 90 MW project located in Pennsylvania, US with a 15-year purchase agreement with Microsoft; and ii) a 29 MW project located in New Hampshire, US with two 20-year purchase agreements with investment grade counterparties. In addition, we entered into a 20-year agreement with the Alberta Electric System Operator (AESO) for the 207 MW Windrise wind project in Alberta, Canada. We expect this growth to create approximately $40 to $45 million of new EBITDA in the consolidated company, with an average contract tenure of more than 18 years.

TransAlta Renewables acquired the economic interest in the Pennsylvania and New Hampshire wind projects. TransAlta Renewables is fully responsible for the capital costs associated with their construction. Further, the Windrise project is a drop down candidate for TransAlta Renewables. Growth projects that are dropped down to TransAlta Renewables are not funded from capital out of TransAlta. TransAlta Renewables has its own credit line, has the ability to raise project debt or tax equity on a project-by-project basis and also has its own source of free cash flow to fund these projects. TransAlta's 61% ownership of TransAlta Renewables also has the effect of lowering the cost of capital at TransAlta.

Coal-to-Gas Conversions: Growing TransAlta

The coal-to-gas conversions, including the pipeline, are very much growth-oriented as they will result in the cumulative life extension of our fleet by approximately 75 years, assuming all units are converted. The conversions will provide competitive, reliable, low cost power to the Alberta market and are expected to position us well in the anticipated Alberta capacity market. In 2018, we exercised our option to acquire 50 percent ownership in the Pioneer Pipeline, which will allow us to increase the amount of natural gas we co-fire at Sundance and Keephills and also facilitates the acceleration of the coal-to-gas conversions. The capital that we have committed to the Pioneer Pipeline is a significant milestone as it represents our first official capital investment in our coal-to-gas conversion strategy. The expected return on the coal-to-gas conversions far exceeds our cost of capital and makes it a clear winner for value creation. At the beginning of 2019, we received regulatory approval for our coal-to-gas conversions.

2019 and Beyond

As we look forward, we expect to see the cash flow from the Alberta hydro assets to naturally grow once its PPA expires. This is due to the fact we will fully benefit from the value tied to the capacity, energy and ancillary services associated with these long-term assets. Our Alberta hydro assets are essential to the Alberta market as they provide significant benefits in their unique ability to both provide reserves and respond quickly to changes in electricity demand. Our reinvestment in these hydro assets is unwavering as it provides shareholders with an interest in a set of assets that are scarce (in Alberta) and provide service into perpetuity.

Regardless of the political environment in Alberta that may emerge, we are positioned to respond effectively. The two policies in particular that warrant attention are: i) policies pertaining to market design, and ii) policies pertaining to greenhouse gases. The AESO has announced an intention to implement a capacity market in Alberta to be effective in 2021. We support the implementation of the capacity market because it provides for an effective replacement of the current capacity commitment under the legislated power purchase arrangements. A capacity market is an efficient way to ensure capacity is available in Alberta when consumers need power, regardless of whether the wind blows or the weather is cold. We also know that even more stable capacity is needed as the development of renewables increase over time, due to the intermittent nature of the renewable generation. We also expect that as renewable generation continues to get cheaper and more desirable by customers, there can be a shortfall of capacity if the price isn't transparent and there isn't a concerted effort to call for enough new capacity. We also see an unrelenting demand by the public to reduce greenhouse gases in the production of electricity. We expect that large emitters will always pay something for their emissions.

This annual report marks our 7th year of reporting our own sustainability goals. I personally helped develop our sustainability goals in 1989 and bought our first carbon offsets in 1991. TransAlta has always been ahead of the market on how sustainability - both environmental sustainability AND economic sustainability - sets the context for how we do our work. By 2030, we will have reduced greenhouse gases by 60%, reduced SO_2 by 95% and reduced NO_x by 50% compared to 2015 levels. Our sustainability goals now touch on every aspect of our strategy, whether it's the coal-to-gas conversions, continuing to support our hydro assets in Alberta or growing TransAlta Renewables.

Owning TransAlta
One of the darkest days in my life as a CEO was January 18, 2016. On that day, the stock traded at $3.76. This was the result of a number of factors, not least of which was the Government of Alberta's stated intention to cease coal-fired emissions by 2030. TransAlta responded quickly and decisively to that reality. We initiated and engaged in negotiations with the Government of Alberta, which ultimately resulted in the recovery of approximately $37 million in annual Off-Coal payments. We also reduced our corporate recourse debt from $3.4 billion to $1.6 billion since 2015. Our success in stepping up to this challenge is reflected in our share performance since January 2, 2016, as compared to our peers on the TSX and the TSX utility capped index. Our return since that day has been approximately 35% annualized, including the dividend. This return has been achieved even though we are only half-way through our transformation.

This is not to suggest that you need to wait until 2022 to realize value. We know that shareholders expect more and expect more sooner. As detailed above, the company remains focused on i) the conversions to gas (including their ability to compete in the capacity market), ii) pursuing incremental growth at TransAlta Renewables; and iii) competitively positioning the Alberta hydro assets in Alberta. These priorities, taken together, are expected to generate sufficient free cash flow in order to allow us to allocate capital to new growth projects, pay shareholder dividends, complete share buy-backs or fund additional debt reduction. By remaining focused and dedicated to this strategy, we are confident in our ability to create sustainable shareholder value.

As always, we appreciate your input as we move through this transition. I will leave with you one final thought. As we go beyond 2020, we are focused on implementing our capital allocation strategy that balances the demand associated with reinvestment, growth, debt repayments and, not least of which, providing shareholders a return on their capital.

Dawn L. Farrell
President and Chief Executive Officer

February 26, 2019

Message from the Chair

Dear Fellow Shareholders,

2018 marked a strong year of financial and operating performance for TransAlta. Our improving performance is just one indicator of progress. The bigger indicator that TransAlta is on the right track, is the enhanced clarity and confidence we have related to our future of clean power generation and our ability to unlock and create value from our diverse portfolio of assets.

Resilience, Strength and Focus
TransAlta has come a long way from the regulatory uncertainty and balance sheet complexity of just four years ago. The extent of our transformation speaks to the resilience of our business, strength of our team and relentless focus on execution. While these are significant accomplishments, our job as your Board is to keep looking ahead, and to ensure the actions we are taking today will continue the momentum towards future success.

In 2018, TransAlta maintained focus on this future by accelerating debt repayment, advancing the transition from coal to gas, while making strategic investments to drive incremental growth and future cash flows. With one of the strongest balance sheets in the sector, TransAlta invested in its clean power future by acquiring wind farm developments with long-term contracted revenue streams and made a critical investment in the gas pipeline for the conversion of our coal plants to gas. We also bought back shares under our share buy-back program, something we will continue to act on when the right opportunity arises. These steps along with continued work on the new market design and confidence in the long-term value of existing hydro and wind assets provide a firm foundation for delivery of shareholder value.

Furthermore, to ensure we have the talent and expertise to lead TransAlta into the future, we added talent to our executive team in 2018 with the addition of Christophe Dehout as Chief Financial Officer, Kerry O'Reilly as Chief Legal Officer, and Jane Fedoretz, as Chief Talent & Transformation Officer. All three executives bring enthusiasm, experience and intellect to support the company's evolution to a leaner, more efficient, more profitable customer-focused culture.

We continue to bring fresh insight and broad experience to our Board which offers diversity of experience, tenure and perspective. Over the past eighteen months, we have been able to attract two very talented Directors in the Honourable Rona H. Ambrose and Bryan D. Pinney. Our Directors, with an average tenure of six years, bring expertise in all aspects of TransAlta's business and their insight and judgement have guided the development and advancement of the long-term strategy.

We have also strategically timed retirements to ensure continuity and stability on the Board. Our long-standing director Timothy Faithfull will retire following our 2019 Annual Shareholder Meeting. On behalf of the Board, I would like to thank Tim for the wealth of knowledge and expertise he has brought to the board during his tenure. For my part, I expect to retire as a director and Chair next year and the Board will be working to identify a new chair through the course of 2019.

As I complete my tenure as Chair, the Board's priority will be to oversee the final stages of TransAlta's transformation plan. We continue to be like the tortoise I referred to last year - consistently moving forward to deliver on our stated goals. The finish line is in sight. With our expert team and diverse portfolio of assets, TransAlta is in a strong position to respond to future clean energy demands and create long-term value for shareholders.

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chair of the Board of Directors
February 26, 2019

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 2018 consolidated financial statements and our Annual Information Form for the year ended Dec. 31, 2018. 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 Board ("IASB") and in effect at Dec. 31, 2018. All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted and except amounts per share which are in whole dollars to the nearest two decimals. This MD&A is dated February 26, 2019. 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****. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws, and "forward-looking statements" within the meaning of applicable United States securities laws, including the United States *Private Securities Litigation Reform Act* of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can"; "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast" "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from that set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements including, but not limited to: our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2018 to 2031 and beyond; potential for growth in renewables and greenfield development acquisitions; the amount of capital allocated to new growth or development projects; our business, anticipated future financial performance and anticipated results, including our outlook and performance targets; our expected success in executing on our growth projects; the timing and the completion of growth and development projects, and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend and maintenance, and the variability of those costs; the conversion of our coal-fired units to natural gas, and the timing and costs thereof; the form and terms of any definitive agreement with Tidewater, as defined below, regarding the construction of a pipeline; the terms of the current or any further proposed normal course issuer bid, including timing and number of shares to be repurchased pursuant to the normal course issuer bid and the acceptance thereof by the Toronto Stock Exchange; the mothballing of certain units; the impact of certain hedges on future earnings, results and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity, including for clean energy, 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 and other fuel 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, including the change to a capacity market in Alberta and the 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 marketing and trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense and the adequacy of tax provisions; changes in accounting estimates and accounting policies; anticipated growth rates and competition in our markets; our expectations and obligations and anticipated liabilities 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 US dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; and our credit practices.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the investment and credit markets; assumptions related to 2019 guidance include: Alberta spot power price equal to $50 to $60 per megawatt hours ("MWh"); Alberta contracted power price equal to $50 to $55 per MWh; Mid-C spot power prices equal to US$20 to US$25 per MWh; Mid-C contracted power price of US$47 to US$53 per MWh; sustaining capital between $160 million and $190 million; productivity capital of $10 million to $15 million; Sundance coal capacity factor of 30% and hydro and wind resource being approximately in line with long-term averages; our proportionate ownership of TransAlta Renewables not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion; assumptions regarding the ability of the converted units to successfully compete in the Alberta capacity market; and assumptions regarding the our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables and being able to realize the full economic benefit from the capacity, energy and ancillary services from our Alberta hydro assets once the applicable power purchase arrangement has expired.

Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include, but are not limited to, risks relating to: fluctuations in market prices; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; the legislative, 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 or market 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 and other climate-change related risks; unexpected increases in cost structure and disruptions in the source of fuels, water or wind required to operate our facilities; failure to meet financial expectations; natural and man-made disasters, including those resulting in dam or dyke failures; 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 and energy trading risks; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects or delays in the closing of acquisitions; increased costs or delays in the construction or commissioning of pipelines to converted units; changes in expectations in the payment of future dividends, including from TransAlta Renewables Inc.; inadequacy or unavailability of insurance coverage; downgrades in credit ratings; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation, including as it pertains to establishing commercial operations at the South Hedland Power Station; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and the Risk Factors section in our Annual Information Form for the year ended Dec. 31, 2018.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on them, which reflect the Corporation's expectations only as of the date hereof. 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 statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated 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 consolidated financial statements but is not presented elsewhere in the consolidated 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, 2018, 2017 and 2016. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

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, are not standard measures 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. Comparable EBITDA, FFO, FCF, total consolidated net debt, adjusted net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Discussion of Consolidated Financial Results, Segmented Comparable Results, Key Financial Ratios and TransAlta's Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Business Model

Our Business

We are one of Canada's largest publicly traded power generators with over 108 years of operating experience. We own, operate and manage a highly contracted and geographically diversified portfolio of assets representing 8,273 MW(1) of capacity and use a broad range of generation fuels comprised of coal, natural gas, water, solar 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.

Vision and Values

Our vision is to be a leader in clean energy using our expertise, scale and diversified fuel mix to capitalize on opportunities in our core markets and grow in areas where our competitive advantages can be employed. Our values are grounded in accountability, integrity, safety, respect for people, innovation and loyalty, which together create a strong corporate culture and allow all of our people to work on a common ground and understanding. These values are at the heart of our success.

Strategy for Value Creation

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 and diversifying our existing assets and further expanding our overall portfolio and operations in Canada, the US and Australia. We are focusing on these geographic areas as our expertise, scale and diversified fuel mix allow us to create expansion opportunities in our core markets.

Material Sustainability Impacts

Sustainability means ensuring that our financial returns consider short- and long-term economics, environmental impacts and societal and community needs. We track the performance of 74 sustainability-related Key Performance Indicators ("KPIs"). We obtained a limited assurance report from Ernst & Young LLP over material KPIs. This MD&A integrates our financial and sustainability reporting.

(1) We measure capacity as maximum capacity (see the 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 reflect the basis of consolidation of underlying assets.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	**2018**	2017	2016
Revenues	**2,249**	2,307	2,397
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Cash flow from operating activities	**820**	626	744
Comparable EBITDA[1]	**1,123**	1,062	1,144
FFO[1]	**927**	804	734
FCF[1]	**524**	328	257
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.86)**	(0.66)	0.41
FFO per share[1]	**3.23**	2.79	2.55
FCF per share[1]	**1.83**	1.14	0.89
Dividends declared per common share	**0.20**	0.12	0.20
Dividends declared per preferred share[2]	**1.29**	0.77	1.36

As at Dec. 31	**2018**	2017	2016
Total assets	**9,428**	10,304	10,996
Total consolidated net debt[1][3]	**3,141**	3,363	3,893
Total long-term liabilities	**4,421**	4,311	5,116

(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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(2) Weighted average of the Series A, B, C, E, and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(3) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, tax equity and finance lease obligations, net of available cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure section of this MD&A for more details on the composition of total consolidated net debt.

FCF, one of the Corporation's key financial metrics, totalled $524 million, up $196 million compared to last year. After adjusting for the one-time receipt for the termination of the Sundance B and C power purchase arrangements ("PPAs") in 2018 and the Ontario Electricity Financial Corporation ("OEFC") payment in 2017 (net of our partners share), FCF was $367 million or $56 million higher than 2017. FFO was $927 million for 2018, compared to $804 million for 2017, an increase of $123 million.

- All generation segments had cash flows equal to or better than the same period last year.
- In Alberta, Canadian Coal, Hydro and our wind assets benefited from higher power prices. Average prices during the year in Alberta increased to $50 per MWh from $22 per MWh in 2017, mainly reflecting the impact of higher carbon pricing costs paid by certain generators and stronger market conditions.
- Canadian Coal cash flows were significantly higher in 2018 compared to 2017 as the cash flows in the first quarter included the one-time receipt for the termination of the Sundance B and C PPAs, which reflects the receipt of the capacity payments that would have been received over the 2018 to 2020 period had these PPAs not been terminated.
- Sustaining capital was lower in 2018 relative to 2017, primarily because of lower capital requirements in Canadian Coal as a result of the retirement of Sundance Units 1 and 2 and the mothballing of Sundance Units 3 and 5, and lower capital requirements in Canadian Gas and US Coal, mainly due to the timing of outages.

Revenues in 2018 were $2,249 million, down $58 million compared to 2017, mainly as a result of lower production within the Canadian Coal segment due to the retirement of Sundance Units 1 and 2 and the mothballing of Sundance Units 3 and 5 resulting from the termination of the Sundance B and C PPAs. This was partially offset by increased prices in the Alberta market.

Comparable EBITDA for the year ended Dec. 31, 2018, was $1,123 million, up $61 million compared to 2017, mainly due to the one-time receipt of $157 million for the termination of the Sundance B and C PPAs, partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs. Excluding unrealized mark-to-market losses, comparable EBITDA was $1,145 million. Beginning in the first quarter of 2019, unrealized mark-to-market gains or losses will be excluded from comparable EBITDA to be more comparable with other companies in the industry.

Net loss attributable to common shareholders in 2018 was $248 million ($0.86 net loss per share) compared to a net loss of $190 million ($0.66 net earnings per share) in 2017. Earnings in 2018 were negatively impacted by higher mine depreciation and carbon compliance costs included in fuel and purchased power, higher impairments, lower finance lease income due to the sale of the Solomon facility, and higher preferred share dividends due to the timing of declarations, partially offset by the one-time receipt of $157 million for the termination of the Sundance B and C PPAs and lower income tax expense. Net loss attributable to common shareholders in 2017 was negatively impacted by lower comparable EBITDA of $82 million as well as the reduction of the US tax rate announced in December ($105 million). The US tax rate reduction was offset by an increase in other comprehensive income.

Significant Events

During 2018, our strategic focus continued to be on reducing our corporate debt, improving our operating performance and transitioning to clean power generation. The Corporation made the following progress in executing upon its strategy throughout the period:

- On Dec. 17, 2018, we exercised our option to acquire a 50 per cent ownership in the gas pipeline ("Pioneer Pipeline") connecting Tidewater Midstream and Infrastructure Ltd.'s ("Tidewater") Brazeau River Complex to TransAlta's generating units at Sundance and Keephills. Our investment is subject to regulatory approval.
- On Dec. 17, 2018, the Corporation announced that we will invest $270 million in our 207 MW Windrise wind project, which was selected by the Alberta Electric System Operator ("AESO") as one of the two successful projects in the Renewable Electricity Program Round 3.
- On Nov. 13, 2018, we appointed Christophe Dehout as our Chief Financial Officer, replacing Brett Gellner (our then interim Chief Financial Officer), who continues to serve as our Chief Strategy and Investment Officer. Mr. Dehout brings broad experience in power generation and extensive knowledge of capital markets, mergers and acquisitions, corporate finance and corporate transformations.
- On Oct. 19, 2018, TransAlta Renewables announced that the 17.25 MW expansion of the wind facility at Kent Hills, New Brunswick, is fully operational, bringing total generating capacity at the site to 167 MW.
- On Aug. 2, 2018, the Corporation redeemed all of our then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for approximately $425 million, including the principal amount of $400 million, a prepayment premium and accrued and unpaid interest.
- On July 20, 2018, the Corporation monetized the payments under the Off-Coal Agreement ("OCA") with the Government of Alberta and closed an approximate $345 million bond offering bearing interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.
- On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters. The shares were issued at a price of $12.65 per share for gross proceeds of approximately $150 million.
- On May 31, 2018, TransAlta Renewables acquired an economic interest in the 50 MW Lakeswind Wind Farm and 21 MW of solar projects located in the US ("Mass Solar") from TransAlta and acquired ownership of the 20 MW Kent Breeze Wind Farm located in Ontario. The total purchase price for the three assets was approximately $166 million, including the assumption of $62 million of tax equity obligations and project debt. On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million (US$25 million) of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar in order to fund the repayment of Mass Solar's project debt.
- On March 15, 2018, the Corporation redeemed the then outstanding 6.650 per cent US $500 million senior notes due May 15, 2018. The redemption price for the notes was approximately $617 million (US$516 million). Repayment of the US senior notes was funded by cash on hand and our credit facility.
- On Feb. 20, 2018, TransAlta Renewables entered into an arrangement to acquire two construction-ready wind projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"). On April 20, 2018, TransAlta Renewables acquired an economic interest in the Big Level project. The Corporation expects the Antrim acquisition to close in early 2019.
- During the year, the Corporation purchased and cancelled 3,264,500 common shares at an average price of $7.02 per common share through our normal course issuer bid ("NCIB") program, for a total cost of $23 million.
- On March 31, 2018, the Corporation received approximately $157 million in compensation for the termination of the Sundance B and C PPAs from the Balancing Pool.
- On Jan. 1, 2018, the Corporation permanently shutdown Sundance Unit 1 and mothballed Sundance Unit 2. On April 1, 2018, we mothballed Sundance Unit 3 and Sundance Unit 5. On July 31, 2018, we decided to permanently shut down Sundance Unit 2.

See the Significant and Subsequent Events section of this MD&A for further details.

Discussion of Consolidated Financial Results

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, including the comparable figures below, are not defined under IFRS. 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 segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Comparable EBITDA

EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. Interest, taxes, and depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, we reclassify certain transactions to facilitate the discussion of the performance of our business:

- Certain assets we own in Canada (and in 2016 and 2017 in Australia) are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We depreciate these assets over their expected lives;
- We also reclassify the depreciation on our mining equipment from fuel and purchased power to reflect the actual cash cost of our business in our comparable EBITDA;
- In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator ("IESO") relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") effective Jan. 1, 2017. Under the new NUG Contract, we received fixed monthly payments until December 31, 2018 with no delivery obligations. Under IFRS, for our reported results in 2016, as a result of the NUG Contract, we recognized a receivable of $207 million (discounted), a pre-tax gain of approximately $191 million net of costs to mothball the units, and accelerated depreciation of $46 million. In 2017 and 2018, on a comparable basis, we recorded the payments we received as revenues as a proxy for operating income, and continued to depreciate the facility until Dec. 31, 2018; and
- On the commissioning of the South Hedland Power Station in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

Year ended Dec. 31	2018	2017	2016
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Net earnings attributable to non-controlling interests	**108**	42	107
Preferred share dividends	**50**	30	52
Net earnings (loss)	**(90)**	(118)	276
Adjustments to reconcile net income to comparable EBITDA			
Income tax expense (recovery)	**(6)**	64	38
Gain on sale of assets and other	**(1)**	(2)	(4)
Foreign exchange (gain) loss	**15**	1	5
Net interest expense	**250**	247	229
Depreciation and amortization	**574**	635	601
Comparable reclassifications			
Decrease in finance lease receivables	**59**	59	57
Mine depreciation included in fuel cost	**140**	75	65
Australian interest income	**4**	2	—
Adjustments to earnings to arrive at comparable EBITDA			
Impacts to revenue associated with certain de-designated and economic hedges	**—**	2	26
Impacts associated with Mississauga recontracting(1)	**105**	77	(177)
Asset impairment charge(2)	**73**	20	28
Comparable EBITDA	**1,123**	1,062	1,144

(1) Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2018, are as follows: revenue ($108 million), and fuel and purchased power and de-designated hedges ($3 million). Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2017, are as follows: revenue ($101 million), fuel and purchased power and de-designated hedges ($12 million), operations, maintenance and administration ($3 million), and recovery related to a renegotiated land lease ($9 million). Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2016, are as follows: net other operating income ($191 million) and fuel and purchased power and de-designated hedges ($14 million).
(2) Asset impairment charges for 2018 include a $38 million charge related to the retirement of Sundance Unit 2, Lakeswind and Kent Breeze impairment of $12 million and a write-off of project development costs of $23 million (2017 - $20 million retirement of Sundance Unit 1, 2016 - $28 million for the Wintering Hills impairment).

Comparable EBITDA increased by $61 million for the year ended Dec. 31, 2018, compared to 2017. This was mainly due to:

- Our Canadian Coal and Hydro segments were up year over year, and together accounted for an increase of $110 million of comparable EBITDA.
  - At Canadian Coal, the one-time receipt of $157 million for the termination of the Sundance B and C PPAs was partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs.
  - Our Hydro operations benefited from higher market prices for Ancillary Services.
- Our US Coal, Canadian Gas and Australian Gas segments were down compared to 2017 for a combined decrease of $44 million.
  - US Coal was down primarily due to non-cash mark-to-market losses.
  - Our Canadian Gas segment was lower mainly because 2017 comparable EBITDA benefited from the settlement of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor generating facilities, totalling $34 million, which was mostly offset by the positive impact of the Mississauga recontracting and cost reduction initiatives.
  - Our Australian Gas segment was lower mainly due to lower finance income as a result of Fortescue Metals Group Ltd.'s ("FMG") repurchase of the Solomon Power Station partially offset by a full year of operations for the South Hedland Power Station.
- Our Wind and Solar segment benefited from higher merchant prices and insurance proceeds from a tower fire at Wyoming Wind Farm, which were offset by the unfavourable impact of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract, resulting in flat comparable EBITDA.
- Energy Marketing was down $2 million in 2018 compared to 2017, but overall, largely consistent year over year.
- Corporate costs remained consistent with 2017 results.

Our overall results in 2018 included costs of approximately $16 million (2017 - $29 million) in operations, maintenance and administration ("OM&A") and $21 million (2017 - $25 million) in productivity capital relating to Project Greenlight, our transformation initiative. We estimate that the Project Greenlight initiatives generated net $70 million in gross margin, OM&A expenses and capital savings. See the Power Generating Portfolio Capital and Strategic Growth and Corporate Transformation sections of this MD&A for further details regarding Project Greenlight.

Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

The table below reconciles our cash flow from operating activities to our FFO and FCF:

Year ended Dec. 31	**2018**	2017	2016
Cash flow from operating activities	**820**	626	744
Change in non-cash operating working capital balances	**44**	114	(73)
Cash flow from operations before changes in working capital	**864**	740	671
Adjustments			
Decrease in finance lease receivable	**59**	59	57
Other	**4**	5	6
FFO	**927**	804	734
Deduct:			
Sustaining capital	**(168)**	(235)	(272)
Productivity capital	**(21)**	(24)	(8)
Dividends paid on preferred shares	**(40)**	(40)	(42)
Distributions paid to subsidiaries' non-controlling interests	**(169)**	(172)	(151)
Other	**(5)**	(5)	(4)
FCF	**524**	328	257
Weighted average number of common shares outstanding in the year	**287**	288	288
FFO per share	**3.23**	2.79	2.55
FCF per share	**1.83**	1.14	0.89

The increase in FCF was driven by year-over-year stronger cash flow from operating activities of $194 million partially due to the payment for the termination of the Sundance B and C PPAs and lower sustaining and productivity capital expenditures. Higher FCF in 2017 compared to 2016 was also driven by strong cash flow from operations before changes in working capital and reduced sustaining and productivity capital expenditures. FCF in 2016 was lower due to payments made to the Market Surveillance Administrator of $25 million.

The table below bridges our comparable EBITDA to our FFO and FCF:

Year ended Dec. 31	2018	2017	2016
Comparable EBITDA	**1,123**	1,062	1,144
Provisions	**7**	(7)	(114)
Unrealized (gains) losses from risk management activities	**22**	(28)	4
Interest expense	**(187)**	(218)	(229)
Current income tax expense	**(28)**	(23)	(23)
Realized foreign exchange gain (loss)	**5**	15	(5)
Decommissioning and restoration costs settled	**(31)**	(19)	(23)
Other cash and non-cash items	**16**	22	(20)
FFO	**927**	804	734
Deduct:			
Sustaining capital	**(168)**	(235)	(272)
Productivity capital	**(21)**	(24)	(8)
Dividends paid on preferred shares	**(40)**	(40)	(42)
Distributions paid to subsidiaries' non-controlling interests	**(169)**	(172)	(151)
Other	**(5)**	(5)	(4)
FCF	**524**	328	257

Segmented Comparable Results

Segmented cash flows generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, provisions, and non-cash mark-to-market gains or losses. This is the cash flow available to: pay our interest and cash taxes, make distributions to our non-controlling partners and pay dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

Year ended Dec. 31	2018	2017	2016
Segmented cash flow(1)			
Canadian Coal(2)	**279**	175	198
US Coal	**63**	33	21
Canadian Gas(3)	**228**	221	235
Australian Gas	**136**	127	99
Wind and Solar	**211**	201	180
Hydro	**96**	61	53
Generation segmented cash flow	**1,013**	818	786
Energy Marketing	**33**	39	25
Corporate	**(107)**	(108)	(95)
Total segmented cash flow	**939**	749	716

(1) Segmented cash flow is a non-IFRS measure.
(2) 2018 includes $157 million received from the Balancing Pool for the early termination of the Sundance B and C PPAs in the first quarter of 2018.
(3) 2017 includes $34 million from the OEFC relating to the 2017 indexation dispute.

Cash flow generated by the business totalled $939 million in 2018, up $190 million over 2017, mainly due to the one-time receipt of $157 million for the termination of the Sundance B and C PPAs, lower sustaining capital expenditures and higher Ancillary Services revenue from our hydro facilities. Cash flow in 2017 was $33 million higher than 2016 due to disciplined cost control and sustaining capital expenditure allocation.

Canadian Coal

Year ended Dec. 31	2018	2017	2016
Availability (%)	**91.6**	82.0	85.3
Contract production (GWh)	**8,936**	18,683	19,823
Merchant production (GWh)	**5,304**	3,786	3,787
Total production (GWh)	**14,240**	22,469	23,610
Gross installed capacity (MW)(1)	**3,231**	3,791	3,791
Revenues	**912**	999	1,048
Fuel and purchased power	**526**	510	386
Comparable gross margin	**386**	489	662
Operations, maintenance and administration	**171**	192	178
Taxes, other than income taxes	**13**	13	13
Net other operating expense (income)(2)	**(198)**	(40)	(2)
Comparable EBITDA	**400**	324	473
Deduct:			
Sustaining capital:			
Routine capital	**17**	22	33
Mine capital	**42**	28	23
Finance leases	**14**	14	13
Planned major maintenance	**15**	54	100
Total sustaining capital expenditures	88	118	169
Productivity capital	**12**	12	1
Total sustaining and productivity capital	**100**	130	170
Provisions	**(10)**	5	85
Unrealized gains (losses) on risk management activities	**11**	3	7
Decommissioning and restoration costs settled	**19**	11	13
Other	**1**	—	—
Canadian Coal cash flow	**279**	**175**	**198**

(1) On Jan. 1, 2018, 560 MW Sundance Units 1 and 2 were shut down and mothballed, respectively. On April 1, 2018, 774 MW Sundance Units 3 and 5 were mothballed. On July 31, 2018 Sundance Unit 2 was shut down permanently.

(2) In 2018, this includes the $157 million payment for the termination of the Sundance B and C PPAs. In both 2018 and 2017, this includes the $40 million OCA payment.

2018

Availability for the year improved compared to 2017, mainly due to lower planned outages and unplanned outages and derates in 2018.

Production for the year ended Dec. 31, 2018, decreased 8,229 gigawatt hours ("GWh") compared to 2017, primarily due to the retirement and mothballing of certain Sundance units and less dispatching, partially offset by lower planned and unplanned outages.

Revenue for the year ended Dec. 31, 2018, decreased by $87 million compared to 2017, mainly due to lower production offset by higher prices. Revenue per MWh of production rose to approximately $64 per MWh in 2018 from $44 per MWh in 2017, which more than offset the increase in carbon compliance costs and resulted in higher gross margin per MWh in 2018.

Fuel, carbon compliance costs and purchased power costs per MWh were higher in 2018 compared to 2017. Coal costs on a dollar per MWh were higher due to fixed costs and lower tonnage. Pit development work commenced in 2018 at the Highvale mine and is expected to provide the lowest cost fuel for the remaining life of the facilities. Carbon compliance costs were higher in 2018, reflecting the regulated increase in the carbon price and due to the fact that carbon compliance costs are no longer recoverable on the Sundance units as the PPAs have been terminated. Both the fuel and carbon pricing cost increases were as expected.

During the year we commenced co-firing with natural gas. Natural gas combustion produces fewer greenhouse gas ("GHG") emissions than coal combustion, which lowers our GHG compliance costs. The combined impact of relatively low Alberta gas prices and lower GHG compliance costs made this economically viable on the merchant plants for a substantial part of the year.

OM&A costs were lower in 2018 compared to 2017. There are certain fixed and common costs that are required to maintain the remaining operational Sundance units and some one-time OM&A costs were incurred in association with the mothballing and retirement of Sundance Units 1 and 2. We continue to optimize the operations of the facility in response to the merchant market.

Comparable EBITDA for the year ended Dec. 31, 2018, increased $76 million compared to 2017, as a result of the one-time receipt of $157 million for the termination of the Sundance B and C PPAs, partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs.

For the year ended Dec. 31, 2018, sustaining capital expenditures decreased by $30 million compared to 2017, mainly due to lower planned outages and mothballing of units, partially offset by increased mine pit development work. Establishing a new pit provides the lowest cost fuel for the remaining life of the facilities. In 2017, four planned outages were performed throughout the year, while during 2018 there was only one planned major outage at one of our non-operated plants. Overall, for 2018, there are four fewer units in the fleet to maintain, which significantly reduced our sustaining capital costs.

2017

Availability in 2017 was down compared to 2016 due to higher unplanned outages and derates due to coal supply disruptions at our mine during the last half of the year, which also resulted in lower production of 1,141 GWh year over year.

Comparable EBITDA for the year ended Dec. 31, 2017, decreased $149 million compared to 2016, due to the $80 million reversal of the Keephills 1 provision in the fourth quarter of 2016. As expected, fuel and purchased power were impacted by higher coal costs related to the expected higher strip ratio and higher environmental compliance costs in 2017. In addition, we incurred additional costs in the third quarter to mitigate the impact of lower productivity at our mine.

OM&A increased $14 million year over year due mostly to contractor spend on Project Greenlight improvement initiatives ($20 million) and higher material and operating expenses ($5 million), and was partially offset by lower compensation ($11 million). See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

The 2017 results also included $40 million related to OCA payments included in net other operating income. We received our OCA payment in the third quarter.

Sustaining and productivity capital expenditures for the year ended Dec. 31, 2017, were lower by $40 million compared to 2016, mainly due to the timing of major outages in 2017 and pit stops executed in 2016 on our Sundance 1 and 2 units.

US Coal

Year ended Dec. 31	2018	2017	2016
Availability (%)	**60.2**	66.3	88.1
Adjusted availability (%)[1]	**84.6**	86.2	88.9
Contract sales volume (GWh)	**3,329**	3,609	3,535
Merchant sales volume (GWh)	**5,704**	5,488	4,896
Purchased power (GWh)	**(3,665)**	(3,625)	(3,854)
Total production (GWh)	**5,368**	5,472	4,577
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues	**442**	437	380
Fuel and purchased power	**314**	293	281
Comparable gross margin	**128**	144	99
Operations, maintenance and administration	**61**	51	54
Taxes, other than income taxes	**5**	4	4
Comparable EBITDA	**62**	89	41
Deduct:			
Sustaining capital:			
Routine capital	**2**	3	3
Finance leases	**4**	3	3
Planned major maintenance	**11**	29	11
Total sustaining capital expenditures	**17**	35	17
Productivity capital	**—**	3	—
Total sustaining and productivity capital	**17**	38	17
Provisions	**—**	—	7
Unrealized gains (losses) on risk management activities	**(29)**	10	(13)
Decommissioning and restoration costs settled	**11**	8	9
US Coal cash flow	**63**	33	21

(1) Adjusted for dispatch optimization.

2018

Availability for the year was down compared to 2017 due to the timing of dispatch optimization and unplanned outages and derates in the last half of 2018, slightly offset by forced outages at Centralia Unit 1 in January 2017. In 2017 and 2018, both Centralia Units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In both years, we performed major maintenance during that time.

Production was down 104 GWh in 2018 compared to 2017, due mainly to dispatch optimization and increased unplanned outages in the last half of the year.

OM&A costs were $10 million higher in 2018 compared to 2017, due to employee gainshare, annual incentive compensation and retention bonuses, as well as increased disbursements paid to the community fund.

Comparable EBITDA decreased by $27 million compared to 2017 primarily due to unfavourable changes on unrealized mark-to-market positions recorded within fuel and purchased power offset by reduced coal costs and favourable market prices.

Sustaining and productivity capital expenditures for 2018 were $21 million lower than 2017, due to lower planned outages.

US Coal's 2018 cash flow improved by $30 million compared to the prior year, mainly due to stronger operating results excluding unrealized mark-to-market impacts and lower sustaining and productivity capital spend.

2017

Availability was down compared to 2016 due to a forced outage on Centralia Unit 1 in January. Both Centralia Units were taken out of service in February due to low prices in the Pacific Northwest market. We performed major maintenance on both units during that time. The lower availability was not material to our results as our contractual obligations were supplied with less expensive power purchased in the market during the first half of the year.

Production was up 895 GWh in 2017 compared to 2016 due mainly to lower dispatch optimization caused by higher prices in the fourth quarter of 2017. The increased generation was partially offset by higher unplanned and planned maintenance.

Comparable EBITDA increased by $48 million compared to 2016 due to increased sales volumes that led to increased margins from higher market prices and higher contract rates. Lower coal transportation costs and the favourable impact of mark-to-market (year-over-year gain of $13 million) on certain forward financial contracts that do not qualify for hedge accounting also positively impacted comparable EBITDA.

Sustaining and productivity capital expenditures for the year ended Dec. 31, 2017, increased by $21 million compared to 2016 due to planned outages executed during the second quarter of 2017. Productivity capital was invested in the installation of inspection equipment to optimize heat rates on coal and improve air distribution systems.

Canadian Gas

Year ended Dec. 31	2018	2017	2016
Availability (%)	**93.3**	91.6	95.7
Contract production (GWh)	**1,620**	1,504	2,784
Merchant production (GWh)	**93**	244	288
Total production (GWh)	**1,713**	1,748	3,072
Gross installed capacity (MW)(1)	**945**	952	1,057
Revenues	**407**	430	470
Fuel and purchased power	**99**	113	171
Comparable gross margin	**308**	317	299
Operations, maintenance and administration	**48**	53	54
Taxes, other than income taxes	**1**	1	1
Comparable EBITDA	**259**	263	244
Deduct:			
Sustaining capital:			
Routine capital	**4**	8	7
Planned major maintenance	**16**	22	5
Total sustaining capital expenditures	**20**	30	12
Productivity capital	**2**	2	—
Total sustaining and productivity capital	**22**	32	12
Provisions	**—**	3	(2)
Unrealized gains (losses) on risk management activities	**9**	7	(2)
Decommissioning and restoration costs settled	**—**	—	1
Canadian Gas cash flow	**228**	221	235

(1) 2018 and 2017 excludes capacity of Mississauga, which was mothballed in early 2017. All years include production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor Energy ("Suncor"). We continue to own a portion of the facility and have included our portion as a part of gross capacity measures.

2018

Availability for the year ended Dec. 31, 2018, increased 1.7 per cent compared to 2017, mainly due to the 2017 base cycling conversion project at Windsor and lower planned and unplanned outages at Sarnia and Windsor in 2018.

Production for the year decreased 35 GWh compared to 2017, as lower market demand at Sarnia was partially offset by higher production at the Fort Saskatchewan, Ottawa and Windsor facilities.

Comparable EBITDA for 2018 decreased by $4 million compared to 2017, mainly due to the retroactive contract indexation dispute settlement with the OEFC in 2017 ($34 million) offset by the positive impact from the Mississauga recontracting, higher realized pricing at Sarnia and cost reduction initiatives. The Mississauga, Ottawa, Windsor, and our 60 per cent share of Fort Saskatchewan, generating facilities are owned through our 50.01 per cent interest in TransAlta Cogeneration L.P. ("TA Cogen"). The Mississauga recontracting ended in December 2018 and was not renewed.

Sustaining capital totalled $20 million in 2018, a decrease of $10 million mainly due to higher capital spend in 2017, when we completed the scheduled maintenance at Sarnia and the base cycling conversion project at Windsor to increase its flexibility to respond to market prices.

Cash flow at Canadian Gas improved by $7 million for the year ended Dec. 31, 2018, compared to the prior year mainly due to lower sustaining capital spend in 2018, partially offset by lower EBITDA. In 2017, one-time sustaining capital expenditures were incurred for the Windsor base cycling conversion project.

2017

Availability decreased approximately four per cent compared to 2016, primarily due to a planned major inspection at our Sarnia plant, the conversion to the peaking plant at Windsor and an unplanned steam turbine outage at Windsor.

Production in 2017 decreased 1,324 GWh compared to 2016, primarily due to changes in contracts at Mississauga and Windsor at the end of 2016.

Comparable EBITDA for 2017 increased by $19 million compared to 2016, primarily due to the settlement with the OEFC of the retroactive adjustment to price indices at Ottawa and Windsor and the positive impact from the temporary shutdown at our Mississauga gas facility, partially offset by unfavourable changes on unrealized mark-to-market positions in gas contracts that do not qualify for hedge accounting and the reduction in earnings from the change to a peaking contract at our Windsor facility.

Sustaining capital for the year ended Dec. 31, 2017, increased $18 million compared to the same period in 2016, primarily due to the planned major inspection at Sarnia and the base to cycling conversion project at Windsor, which was undertaken to increase its flexibility to respond to market prices.

In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. in Mississauga effective Dec. 31, 2021. TransAlta is required to remove the Mississauga plant and restore the site within the three-year time frame.

Australian Gas

Year ended Dec. 31	**2018**	2017	2016
Availability (%)	**94.0**	93.4	93.1
Contract production (GWh)	**1,814**	1,803	1,529
Gross installed capacity (MW)(1)	**450**	450	425
Revenues	**165**	180	174
Fuel and purchased power	**4**	12	20
Comparable gross margin	**161**	168	154
Operations, maintenance and administration	**37**	31	25
Taxes, other than income taxes	**—**	—	1
Comparable EBITDA	**124**	137	128
Deduct:			
Sustaining capital:			
Routine capital	**2**	9	3
Planned major maintenance	**—**	1	11
Total sustaining and productivity capital	**2**	10	14
Other	**(14)**	—	15
Australian Gas cash flow	**136**	127	99

(1) The 2016 figures include production capacity for the Solomon Power Station, which was accounted for as a finance lease. In 2017, FMG repurchased the Solomon Power Station and therefore was removed from 2017 capacity, which was offset by adding capacity for the South Hedland Power Station, which achieved commercial operations on July 28, 2017.

2018

Availability for the year ended Dec. 31, 2018, increased compared to 2017, mainly due to a full year of operation from the South Hedland Power Station, which was offset by FMG's repurchase of the Solomon Power Station.

Production for 2018 was comparable to 2017, due to the addition of the South Hedland Power Station, which was offset by FMG's repurchase of the Solomon Power Station. Due to the nature of our contracts, changes in production do not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA for the year decreased by $13 million compared to 2017 mainly due to FMG's repurchase of Solomon Power Station, higher OM&A costs due to the addition of the South Hedland Power Station and ongoing legal costs associated with our dispute with FMG, which were partially offset by higher EBITDA from the South Hedland Power Station.

Sustaining and productivity capital for 2018 decreased by $8 million compared to 2017, due to major maintenance incurred at our Southern Cross facility in August 2017 that was not required in 2018.

Cash flow at Australian Gas increased by $9 million in 2018 mainly due to lower sustaining capital requirements and an increase in cash flow from the collection of a long-term receivable, largely offset by lower EBITDA.

2017

Production for 2017 increased by 274 GWh compared to 2016 due to the commissioning of our South Hedland Power Station in July 2017, and an increase in customer load, partially offset by the early termination of our lease for our Solomon Power Station in November 2017. As a result of the early termination, we received US$325 million ($417 million) in the fourth quarter of 2017. Due to the nature of our contracts, the increase in customer load did not have a significant financial impact on our results as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA was up $9 million for 2017 compared to 2016 due to the commissioning of our South Hedland Power Station in July 2017, which was partially offset by the early termination of our lease for our Solomon Power Station in November 2017.

Wind and Solar

Year ended Dec. 31	2018	2017	2016
Availability (%)	**95.4**	95.8	94.9
Contract production (GWh)	**2,363**	2,362	2,301
Merchant production (GWh)	**1,005**	1,098	1,212
Total production (GWh)	**3,368**	3,460	3,513
Gross installed capacity (MW)(1)	**1,382**	1,363	1,408
Revenues	**282**	287	272
Fuel and purchased power	**17**	17	18
Comparable gross margin	**265**	270	254
Operations, maintenance and administration	**50**	48	52
Taxes, other than income taxes	**8**	8	8
Net other operating income	**(6)**	—	(1)
Comparable EBITDA	**213**	214	195
Deduct:			
Sustaining capital:			
Routine capital	**5**	1	2
Planned major maintenance	**8**	10	11
Total sustaining capital expenditures	**13**	11	13
Productivity capital	**2**	2	3
Total sustaining and productivity capital	**15**	13	16
Provisions	**—**	—	(1)
Unrealized gains (losses) on risk management activities	**(20)**	—	—
Decommissioning and restoration costs settled	**1**	—	—
Other (insurance proceeds)	**6**	—	—
Wind and Solar cash flow	**211**	**201**	**180**

(1) The 2017 figure excludes capacity for the Wintering Hills wind facility, which was sold on March 1, 2017.

2018

Availability for the year ended Dec. 31, 2018, was comparable to 2017, which was expected.

Production for 2018 decreased by 92 GWh compared to 2017, mainly due to lower wind resources across Alberta and the United States combined with the sale of the Wintering Hills merchant facility on March 1, 2017. This lower production was partially offset by higher wind resources in Eastern Canada.

Comparable EBITDA for 2018 was comparable with 2017, as higher merchant prices in Alberta and insurance proceeds from the tower fire at Wyoming Wind Farm were offset by the unfavourable impact of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract and the unfavourable impact of lower wind resources.

Wind and Solar's cash flow improved by $10 million for the year ended Dec. 31, 2018, compared to the prior year, due mainly to the addback of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract.

2017

Production for 2017 decreased by 53 GWh compared to 2016 as we sold the Wintering Hills wind facility in the first quarter of 2017. Generation from our other facilities was slightly higher than in 2016.

Comparable EBITDA for 2017 increased $19 million compared to 2016, primarily driven by higher volumes at contracted facilities, price increases on our contracted assets, higher prices in Alberta on our uncontracted assets and lower costs in our long-term service agreements.

Hydro

Year ended Dec. 31	2018	2017	2016
Production			
Energy contracted			
Alberta hydro PPA assets (GWh)[1]	**1,519**	1,530	1,410
Other hydro energy (GWh)[1]	**306**	336	358
Energy merchant			
Other hydro energy (GWh)	**81**	82	88
Total energy production (GWh)	**1,906**	1,948	1,856
Ancillary service volumes (GWh)[2]	**3,265**	3,044	2,623
Gross installed capacity (MW)	**926**	926	926
Revenues			
Alberta hydro PPA assets energy	**90**	36	28
Alberta hydro PPA assets ancillary	**104**	36	30
Capacity payments received under Alberta hydro PPA[3]	**56**	54	55
Other revenue[4]	**41**	43	50
Total gross revenues	**291**	169	163
Net payment relating to Alberta hydro PPA	**(135)**	(48)	(37)
Revenues	**156**	121	126
Fuel and purchased power	**6**	6	8
Comparable gross margin	**150**	115	118
Operations, maintenance and administration	**38**	37	33
Taxes, other than income taxes	**3**	3	3
Net other operating income	**—**	—	—
Comparable EBITDA	**109**	75	82
Deduct:			
Sustaining capital:			
Routine capital, excluding hydro life extension	**4**	8	8
Hydro life extension	**—**	—	9
Planned major maintenance	**8**	5	10
Total before flood-recovery capital	**12**	13	27
Flood-recovery capital	**—**	—	2
Total sustaining capital expenditures	**12**	13	29
Productivity capital	**1**	1	—
Total sustaining and productivity capital	**13**	14	29
Hydro cash flow	**96**	61	53

(1) Alberta hydro PPA assets include 12 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPAs.
(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer.
(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.

2018

Production for 2018 decreased by 42 GWh over 2017, primarily due to lower water resources.

Comparable EBITDA for 2018 increased $34 million compared to 2017. Alberta Hydro benefited from stronger energy prices and a higher demand for Ancillary Services.

Hydro's cash flow improved by $35 million for 2018, compared to 2017, due mainly to higher comparable EBITDA.

2017

Production for 2017 increased by 92 GWh compared to 2016, primarily due to stronger water resources from spring run-off during the first nine months of 2017 in Alberta.

However, comparable EBITDA for the year ended Dec. 31, 2017, decreased by $7 million compared to 2016, due to higher OM&A costs and a $3 million positive adjustment relating to a prior year metering issue at one of our facilities recorded in 2016.

Sustaining capital expenditures for 2017 decreased $16 million compared to 2016 due to lower expenditures on major overhauls. Life extension projects at Bighorn and Brazeau and flood recovery capital spend occurred in 2016.

Energy Marketing

Year ended Dec. 31	2018	2017	2016
Revenues and comparable gross margin	**67**	69	76
Operations, maintenance and administration	**24**	24	24
Comparable EBITDA	**43**	45	52
Deduct:			
Provisions	**3**	(2)	24
Unrealized gains (losses) on risk management activities	**7**	8	3
Energy Marketing cash flow	33	39	25

2018

Comparable EBITDA for 2018 remained fairly consistent with 2017 results, which was expected.

Energy Marketing's cash flows for 2018 decreased by $6 million compared to 2017, mainly due to the settlement of trading positions adversely affected by cold weather in the first quarter and the removal of non-cash mark-to-market gains driven by a number of long-term trades that are expected to settle in 2019.

2017

Comparable EBITDA results were lower by $7 million compared to 2016, due to unfavourable first quarter of 2017 results impacted by warm winter weather in the Northeast, significant precipitation in the Pacific Northwest and reduced margins from our customer business.

Corporate

2018

Our Corporate overhead costs of $87 million were consistent in 2018 compared to 2017 as we realized benefits from cost-efficiency initiatives that were offset by the addition of the Supply Chain Management team, which will provide future cost savings by leveraging our buying power. Corporate cash flow also includes $20 million (2017 - $22 million) in sustaining and productivity capital spend.

2017

Our Corporate overhead costs of $85 million were $14 million higher for the year ended Dec. 31, 2017, compared to 2016 mostly due to higher annual incentive compensation and Project Greenlight initiative fees. See the Strategic Growth and Corporate Transformation section of this MD&A for further details. The first quarter of 2017 also includes the reclassification of incentives for 2016 between our operational segments and our Corporate segment.

Key Financial Ratios

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 help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. We strengthened our financial position and flexibility and met most of our target ranges in 2018.

Funds from Operations before Interest to Adjusted Interest Coverage

As at Dec. 31	2018	2017	2016
FFO	**927**	804	734
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	**(157)**	—	—
Add: Interest on debt and finance leases, net of interest income and capitalized interest	**174**	205	203
FFO before interest	**944**	1,009	937
Interest on debt and finance leases, net of interest income	**176**	214	219
Add: 50 per cent of dividends paid on preferred shares	**20**	20	21
Adjusted interest	**196**	234	240
FFO before interest to adjusted interest coverage (times)	**4.8**	4.3	3.9

Our target for FFO before interest to adjusted interest coverage is four to five times. The ratio improved compared to 2017 due to lower interest on debt as we continued to execute our deleveraging plan.

Adjusted FFO to Adjusted Net Debt

As at Dec. 31	2018	2017	2016
FFO	**927**	804	734
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	**(157)**	—	—
Less: 50 per cent of dividends paid on preferred shares	**(20)**	(20)	(21)
Adjusted FFO	**750**	784	713
Period-end long-term debt(1)	**3,267**	3,707	4,361
Less: Cash and cash equivalents	**(89)**	(314)	(305)
Less: Principal portion of TransAlta OCP restricted cash	**(27)**	—	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt(2)	**(10)**	(30)	(163)
Adjusted net debt	**3,612**	3,834	4,364
Adjusted FFO to adjusted net debt (%)	**20.8**	20.4	16.3

(1) Includes finance lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2018, Dec. 31, 2017, and Dec. 31, 2016.

Our adjusted FFO to adjusted net debt of 20.8 per cent remained consistent with 2017, as the significant reduction in our net debt was offset by a decline in adjusted FFO. We reached the low end of our target range of 20 to 25 per cent in 2017 and maintained that level in 2018.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	2018	2017	2016
Period-end long-term debt(1)	**3,267**	3,707	4,361
Less: Cash and cash equivalents	**(89)**	(314)	(305)
Less: Principal portion of TransAlta OCP restricted cash	**(27)**	—	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt(2)	**(10)**	(30)	(163)
Adjusted net debt	**3,612**	3,834	4,364
Comparable EBITDA	**1,123**	1,062	1,144
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	**(157)**	—	—
Adjusted comparable EBITDA	**966**	**1,062**	**1,144**
Adjusted net debt to comparable EBITDA (times)	**3.7**	3.6	3.8

(1) Includes finance lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2018, Dec. 31, 2017, and Dec. 31, 2016.

Our adjusted net debt to comparable EBITDA ratio increased compared to 2017, mainly due to the decrease in adjusted comparable EBITDA during the year, after adjusting for the payment for the early termination of the Sundance B and C PPAs. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times.

Ability to Deliver Financial Results

The metrics we use to track our performance are comparable EBITDA, FFO and FCF. The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		2018	2017	2016
Comparable EBITDA	Target(1)	**1,000-1,050**	1,025-1,100	990-1,100
	Actual	**1,123**	1,062	1,144
	Adjusted Actual(2)	**988**	1,000	1,068
FFO	Target(1)	**750-800**	765-820	755-835
	Actual	**927**	804	734
	Adjusted Actual(3)	**770**	770	734
FCF	Target(1)	**300-350**	270-310	250-300
	Actual	**524**	328	257
	Adjusted Actual(3)	**367**	311	257

(1) Represents our revised outlook. As a result of strong performance in the first quarter of 2018, we revised the following 2018 targets: comparable EBITDA from the previously announced target range of $950 million to $1,050 million to $1,000 to $1,050 million, FFO from the target range of $725 million to $800 million to $750 million to $800 million FCF target range from $275 million to $350 million to the target range of$300 million to $350 million. In the second quarter of 2017 we reduced the following 2017 targets: Comparable EBITDA from target range of $1,025 million to $1,135 million to $1,025 to $1,100 million, FFO from the target range of $765 million to $855 million to $765 million to $820 million FCF target range from $300 million to $365 million to the target range of $270 million to $310 million.
(2) Comparable EBITDA for all periods was adjusted to remove the impact of unrealized mark-to-market gains or losses. Additionally, 2018 was adjusted to remove the $157 million for the termination of the Sundance B and C PPAs as this was not included in the target. 2017 was also adjusted to remove the $34 million related to the OEFC indexation dispute. 2016 was adjusted for the $80 million impact for non-cash adjustments related to the Keephills 1 provision.
(3) 2018 amounts were adjusted to remove the $157 million for the termination of the Sundance B and C PPAs as this was not included in the targets. 2017 amounts were adjusted to remove the OEFC indexation dispute: FFO was reduced by $34 million and FCF was reduced by $17 million.

Significant and Subsequent Events

Transition to Clean Power in Alberta

Alberta Renewable Energy Program Project - Windrise

In the fourth quarter of 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the two successful projects in the third round of the Renewable Electricity Program. The Windrise facility, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately $270 million and is targeted to reach commercial operation during the second quarter of 2021.

Gas Supply for Coal-to-Gas Conversions

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. Tidewater will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline will provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately $90 million. Construction of the pipeline commenced in November 2018 and the Pioneer Pipeline is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals, which are expected to be finalized in the first half of 2019.

The decision to work with Tidewater advances the time frame for the construction of the Pioneer Pipeline and permits the acceleration of plant conversions. TransAlta remains of the view that having at least two pipelines supplying natural gas would reduce operational risks and continues to advance discussions with other parties to construct additional pipelines to meet the remaining gas supply requirements for the facilities.

Sundance and Keephills Units 1 and 2 Coal-to-Gas Conversion Strategy

On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. During 2018, the Corporation mothballed and retired the following Sundance Units:

- retired Sundance Unit 1 on Jan. 1, 2018;
- retired Sundance Unit 2 on July 31, 2018;
- temporarily mothballed Sundance Unit 3 on April 1, 2018, for a period of up to two years; and
- temporarily mothballed Sundance Unit 5 on April 1, 2018, for a period of up to one year, which has recently been extended to two years.

TransAlta is no longer planning to temporarily mothball Sundance Unit 4 and will perform maintenance during the first half of 2019.

On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The regulations provide rules for new gas-fired electricity facilities, as well as specific provisions for coal-to-gas conversions. In addition to extending their operating lives, the benefits of converting units to gas generation include: significantly lowering carbon emissions and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility. TransAlta expects to convert its Sundance Units 3 to 6 and Keephills Units 1 to 3 in the 2020 to 2023 time frame.

Sundance Units 1 and 2

Canadian federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 was shut down two years early, the federal Minister of Environment and Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This provided the Corporation with the flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market. However, in July 2018, TransAlta retired Sundance Unit 2. This decision was driven largely by Sundance Unit 2's age, size and short useful life relative to other units, and the capital requirements needed to return the unit to service.

Sundance Units 1 and 2 collectively made up 560 MW of the 2,141 MW capacity of the Sundance power plant, which served as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expired on Dec. 31, 2017.

In the third quarter of 2018, the Corporation recognized an impairment charge of $38 million ($28 million after-tax) relating to the retirement of Sundance Unit 2. During the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of $20 million ($15 million after-tax) due to the Corporation's decision to early retire Sundance Unit 1.

Kent Hills 3 Wind Project

During 2017, a subsidiary of TransAlta Renewables Inc., Kent Hills Wind LP ("KHWLP"), entered into a long-term contract with New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 expansion wind project. At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035, matching the life of the Kent Hills 2 and Kent Hills 3 wind projects.

On Oct. 19, 2018, TransAlta Renewables announced that the expansion was fully operational, bringing the total generating capacity of the Kent Hills wind farm to 167 MW.

Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire two construction-ready projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 2018, whereas the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the Antrim acquisition to close in early 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables and a $25 million promissory note receivable and are estimated to be US$240 million. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs using its existing liquidity and tax equity.

During the year ended Dec. 31, 2018, TransAlta Renewables funded approximately $61 million (US$48 million) of construction costs for Big Level. On Jan. 2, 2019, TransAlta Renewables funded an additional $45 million (US$33 million) of construction costs.

TransAlta Renewables Acquires Three Renewable Assets from the Corporation

On May 31, 2018, TransAlta Renewables acquired from a subsidiary of the Corporation an economic interest in the 50 MW Lakeswind wind farm in Minnesota and 21 MW of solar projects located in Massachusetts ("Mass Solar") through the subscription of tracking preferred shares of a subsidiary of the Corporation. In addition, TransAlta Renewables acquired from a subsidiary of the Corporation ownership of the 20 MW Kent Breeze wind farm located in Ontario. The total purchase price for the three assets was approximately $166 million, including the assumption of $62 million of tax equity obligations and project debt, for net cash consideration of $104 million. The Corporation continues to operate these assets on behalf of TransAlta Renewables.

On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar, in order to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge, of which $11 million was recorded against property, plant and equipment ("PP&E") and $1 million against intangibles.

TransAlta Renewables Closes $150 Million Offering of Common Shares

On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters. The common shares were issued at a price of $12.65 per common share for gross proceeds of approximately $150 million ($144 million of net proceeds).

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility is to be used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described above.

The Corporation did not purchase any additional common shares under the offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables.

$345 Million Financing
On July 20, 2018, the Corporation monetized the payments under the OCA with the Government of Alberta by closing a $345 million bond offering through its indirect wholly owned subsidiary, TransAlta OCP LP ("TransAlta OCP"). The offering was a private placement that was secured by, among other things, a first ranking charge over the OCA payments payable by the Government of Alberta. The amortizing bonds bear interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The bonds have a rating of BBB, with a stable trend, by DBRS. Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

Early Redemption of $400 million of Debentures
On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of $400 million . The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest.

Normal Course Issuer Bid
On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.86 per cent of issued and outstanding common shares as at March 2, 2018. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018, and ends on March 13, 2019, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 102,039 common shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 common shares for the six months ended February 28, 2018) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million. Further transactions under the NCIB, if any, will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

Early Redemption of Senior Notes
On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US $500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense for the three months ended March 31, 2018.

Management and Board of Directors Changes
Donald Tremblay, the former Chief Financial Officer ("CFO"), left the Corporation, effective May 9, 2018. Brett Gellner, Chief Strategy and Investment Officer, acted as Interim CFO, in addition to his current role, during the interim period.

During the fourth quarter of 2018, we appointed Christophe Dehout as our CFO. Mr. Dehout brings broad experience in power generation and extensive knowledge of capital markets, mergers and acquisitions, corporate finance and corporate transformations.

On January 25, 2019, we announced the retirement decisions of Timothy Faithfull and Ambassador Gordon Giffin. Earlier in 2018, Mr. Faithfull had indicated to the Board his intention to retire from the Board of Directors immediately following TransAlta's 2019 Annual Shareholders Meeting and, also in 2018, Ambassador Gordon Giffin announced his intention to retire as director and Board Chair in 2020. The Board is undertaking a process to identify a new Chair through the course of 2019.

Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements
On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective March 31, 2018.

The termination of the Sundance B and C PPAs by the Balancing Pool was expected and the Corporation is working to ensure it receives the termination payment that it believes it is entitled to under the Sundance B and C PPAs and applicable legislation. The Balancing Pool paid the Corporation approximately $157 million on March 29, 2018, as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

Please refer to Note 4 of the audited annual 2018 consolidated financial statements for significant events impacting prior year results.

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2017, to Dec. 31, 2018:

Assets	**Increase/ (decrease)**	**Primary factors explaining change**
Cash and cash equivalents	(225)	Timing of receipts and payments.
Restricted cash (current & long-term)	36	Restricted cash related to the TransAlta OCP bonds ($35 million)
Trade and other receivables	(177)	Timing of customer receipts, collection of Mississauga recontracting receivable ($108 million), partially offset by the Antrim promissory note receivable ($25 million)
Inventory	23	Increase in Canadian Coal ($50 million) partially offset by a reduction in purchased emission credits ($13 million) and a reduction in parts and materials inventory ($5 million)
Finance lease receivables (long term)	(24)	Principal repayments
Property, plant, and equipment, net	(414)	Depreciation for the period ($649 million), revisions to decommissioning and restoration costs ($32 million) and asset impairments ($49 million), partially offset by additions ($294 million) and favourable changes in foreign exchange rates ($39 million)
Intangible assets	9	Additions of ($53 million) and net transfers from PP&E ($6 million), partially offset by amortization ($50 million)
Risk management assets (current and long term)	(95)	Contract settlements and unfavourable market price movements, partially offset by favourable changes in foreign exchange rates
Other	(9)	
Total change in assets	**(876)**	

Liabilities and equity	**Increase/ (decrease)**	**Primary factors explaining change**
Accounts payable and accrued liabilities	(98)	Timing of payments and accruals
Income taxes payable	(54)	Primarily due to the payment of taxes on FMG's repurchase of the Solomon Power Station
Credit facilities, long term debt, and finance lease obligations (including current portion)	(440)	Repayment of long-term debt ($1,179 million), partially offset by drawings on the credit facility ($312 million), long-term debt issued ($345 million) and unfavourable changes in foreign exchange ($95 million)
Decommissioning and other provisions (current and long term)	(14)	Liabilities settled ($41 million) and an increase in risk-adjusted discount rates ($37 million), partially offset by accretion ($24 million), new liabilities incurred ($22 million), remaining payment for Big Level acquisition ($8 million) and unfavourable changes in foreign exchange ($10 million)
Contract liabilities	25	Increased due to IFRS 15 transition adjustment ($17 million), consideration received ($13 million) and interest accrued and expensed during the period ($6 million), partially offset by transfers to revenue ($10 million)
Defined benefit obligation and other long term liabilities	(10)	Decrease in the defined benefit obligation ($8 million) and reduced employee incentive plan liability ($7 million), partially offset by increased other long-term liabilities ($5 million)
Deferred income tax liabilities	(48)	Decrease in taxable temporary differences
Equity attributable to shareholders	(329)	Net loss ($198 million), net other comprehensive loss ($12 million) common share dividends ($57 million), preferred share dividends ($50 million), shares purchased under NCIB ($23 million), impact of changes in our accounting policies ($14 million), partially offset by changes in non-controlling interests in TransAlta Renewables ($24 million)
Non-controlling interests	78	Net earnings ($108 million), changes in non-controlling interests in TransAlta Renewables from share issuance ($133 million) and intercompany FVOCI investments ($16 million), partially offset by distributions paid and payable ($180 million)
Other	14	
Total change in liabilities and equity	**(876)**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2017, and Dec. 31, 2016, compared to the year ended Dec. 31, 2018:

Year ended Dec. 31	2018	2017	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of year	**314**	305	9	
Provided by (used in):				
Operating activities	**820**	626	194	Higher cash flow from operations before working capital ($124 million) and a favourable change in non-cash working capital ($70 million)
Investing activities	**(394)**	87	(481)	Lower proceeds on sale of Wintering Hills wind facility and Solomon ($476 million), unfavourable change in non-cash investing capital ($153 million) and the acquisition of Big Level and Antrim ($30 million), partially offset by lower additions to property, plant, and equipment ($63 million), lower tax expense relating to investing activities ($56 million), lower additions to intangibles ($31 million), and the lower issuance of loan receivable ($39 million)
Financing activities	**(651)**	(703)	52	Increase in borrowings under credit facilities ($286 million), higher issuance of long-term debt ($85 million), and higher proceeds on the sale of non-controlling interest in a subsidiary ($144 million), partially offset by higher repayments of long-term debt ($365 million), lower realized gains on financial instruments ($58 million) and repurchase of common shares ($23 million)
Translation of foreign currency cash	**—**	(1)	1	
Cash and cash equivalents, end of year	**89**	314	(225)	

Year ended Dec. 31	2017	2016	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of year	305	54	251	
Provided by (used in):				
Operating activities	626	744	(118)	Unfavourable change in non-cash working capital of ($187 million), partially offset by higher cash earnings ($69 million)
Investing activities	87	(327)	414	Proceeds on sale of Wintering Hills wind facility and Solomon power station disposition ($478 million), net loan receivable ($38 million), and restricted cash ($30 million)
Financing activities	(703)	(163)	(540)	Higher repayment of long-term debt ($726 million), lower issuance of long-term debt ($101 million), and lower proceeds on sale of non-controlling interest in subsidiary ($162 million), partially offset by lower borrowings under credit facility ($341 million), higher realized gains on financial instruments ($108 million), and lower dividends paid on common shares ($23 million)
Translation of foreign currency cash	(1)	(3)	2	
Cash and cash equivalents, end of year	314	305	9	

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices, and currency fluctuations, as well as other market risks. We may 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. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale, or usage requirements ("own use") and as such, are not considered financial instruments and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and 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.

Some of our financial instruments and physical commodity contracts 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 mainly used for cash flow 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.

We have 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 necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

The fair value of derivatives 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.

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.

Foreign currency forward contracts may be used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures, and currency exposures related to US-denominated debt.

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options may be 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 may be used to offset the exposures resulting from foreign-denominated long-term debt. Interest rate swaps may be used to convert the fixed interest cash flows related to interest expense at debt to floating rates and vice versa.

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

Under IFRS 9, which we adopted on Jan. 1, 2018, hedge accounting requirements were simplified, to introduce a more principles based approach for qualifying hedges, aligned with an entity's approach to risk management, and to revise and simplify the hedge effectiveness requirements.

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-denominated long-term debt is 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. Our net investment hedges using US-denominated debt remain effective and in place. 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 also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our US operations with interest payments on our US dollar debt.

Non-Hedges
Financial instruments not designated as hedges are used for proprietary trading and 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 consolidated financial statements. At Dec. 31, 2018, Level III instruments had a net asset carrying value of $695 million (2017 - $771 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, 2017.

2019 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2019:

Measure	Target
Comparable EBITDA	$875 million to $975 million
FCF	$270 million to $330 million
Dividend	$0.16 per share annualized, 14 to 17 per cent payout of FCF

Range of key power price assumptions

Market	Power Prices ($/MWh)
Alberta Spot	$50 to $60
Alberta Contracted	$50 to $55
Mid-C Spot (US$)	$20 to $25
Mid-C Contracted (US$)	$47 to $53

Other assumptions relevant to 2019 financial outlook	
Sustaining Capital	$160 million to $190 million
Productivity Capital	$10 million to $15 million
Sundance coal capacity factor	30%
Hydro/ Wind Resource	Long term average

Operations
Availability and Capacity
Availability of our coal fleet is expected to be in the range of 87 to 89 per cent in 2019. Availability of our other generating assets (gas, renewables) is expected to be in the range of 92 to 96 per cent in 2019. We will be accelerating our transition to gas and renewables generation, and continue on our coal-to-gas conversion strategy as set out in the Significant and Subsequent Events section of this MD&A.

Market Pricing and Hedging Strategy
For 2019, power prices in Alberta are expected to be slightly higher than 2018 due to a full year of lower supply as a result of the mothballing and shutdown of certain coal-fired units in 2018. Pacific Northwest power prices for 2019 are expected to be lower than 2018 as 2018 prices were impacted by specific events that are not expected to occur in the future. Ontario power prices are expected to remain consistent with 2018 prices.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF which also provides for positive exposure to price volatility in Alberta. Given our cash operating costs, we can be more or less hedged in a given period, and we expect to realize our annual FCF targets through a combination of forward hedging and selling generation into the spot market.

Fuel Costs

In Alberta, we expect the 2019 cash fuel costs for coal to be slightly lower than the 2018 costs and total fuel costs to be lower due to increased co-firing with natural gas among the merchant units.

In the Pacific Northwest, our US Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at US Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. In 2017 we amended our fuel and rail contract such that our costs fluctuate partly with gas prices. The delivered fuel cost in 2019 is expected to be consistent with 2018 costs.

Most of our generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provisions, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

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

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2019 objective for Energy Marketing is for the segment to contribute between $75 million to $85 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 US dollar, and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2019 is expected to be lower than in 2018 largely due to lower levels of debt. However, changes in interest rates and in the value of the Canadian dollar relative to the US dollar can affect the amount of net interest expense incurred. In addition, interest expense will increase as a result of implementing IFRS 16. See the Accounting Changes section of this MD&A for further details.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.0 billion in liquidity including $89 million in cash. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturity in 2020.

Capital Expenditures

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

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

	Total project		2019		
	Estimated spend	Spent to date[(1)]	Estimated spend	Target completion date	Details
Project					
Big Level wind development project[(2)]	214	84	130	Q3 2019	90 MW wind project with a 15-year PPA
Antrim wind development project[(3)]	97	25	72	Q3 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	90	15	75	Q4 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Windrise wind development project	270	—	47	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
Total	**671**	**124**	**324**		

(1) Represents amounts spent as of Dec. 31, 2018.
(2) The numbers reflected above are in CAD but the actual cash spend on this project is in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD$165 million, spent to date is USD$65 million and estimated total spend in 2019 is USD$100 million. TransAlta Renewables will fund the construction costs using its existing liquidity and tax equity.
(3) The numbers reflected above are in CAD but the actual cash spend on this project is in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD$75 million, spent to date is USD$19 million and expected total spend in 2019 is USD$56 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity. The project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

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 2017	Spent in 2018	Expected spend in 2019
Routine capital[(1)]	Capital required to maintain our existing generating capacity	69	**50**	50 - 60
Planned major maintenance	Regularly scheduled major maintenance	121	**58**	70 - 80
Mine capital	Capital related to mining equipment and land purchases	28	**42**	20 - 25
Finance leases	Payments on finance leases	17	**18**	20 - 25
Total sustaining capital		235	**168**	**160 - 190**
Insurance recoveries of sustaining capital expenditures	Insurance proceeds related to the fire at Wyoming Wind and Canadian Coal equipment	—	**(7)**	—
Total sustaining capital		235	**161**	**160 - 190**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	24	**21**	10 - 15
Total sustaining and productivity capital		259	**182**	**170 - 205**

(1) Includes hydro life extension expenditures.

Significant planned major outages at TransAlta's operated units for 2019 include the following:

- two outages for major maintenance at Keephills Unit 1 and Sundance Unit 4 within our Canadian Coal segment during Q1 and Q2 2019;
- one major outage in our Canadian Gas segment related to our Sarnia facility during Q2 2019;
- distributed planned maintenance expenditures across the entire Hydro fleet; and
- distributed expenditures across our wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2019:

	Coal	Gas and renewables	Total
GWh lost	500 - 550	400 - 450	900 - 1,000

Funding of Capital Expenditures
Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities and existing liquidity. We have access to approximately $1.0 billion in liquidity, if required. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of our monitoring controls, long-range forecasts are prepared for each Cash Generating Unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide a criteria to evaluate adverse changes in operations. When indicators of impairment are present, we estimate a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets.

Alberta Merchant CGU
During 2018, 2017, and 2016, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan, the future design parameters of the Alberta electricity market, and federal policies on the carbon levy and GHG emissions. Economic conditions also contributed to continued oversupply conditions and depressed market prices throughout 2015 to 2017. The Corporation assessed whether these factors, and events arising during the latter part of 2016, which are more fully discussed below, presented an indicator of impairment for its Alberta Merchant CGU. In consideration of the composition of this CGU, the Corporation determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, the Corporation did not perform an in-depth impairment analysis for any of these years, but for all years, a sensitivity analysis associated with these factors was performed to confirm the continued existence of adequate excess of estimated recoverable amount over book value. This analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU in each of 2018, 2017, and 2016, due to the Corporation's large merchant renewable fleet in the province.

2018

Sundance Unit 2
In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on July 31, 2018. Discounting did not have a material impact.

Lakeswind and Kent Breeze
On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze. In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E, and a $1 million impact on Intangible assets.

2017

Sundance Unit 1
In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated

future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintained the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU to 2021.

2016

Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. In connection with this sale, the Wintering Hills assets were accounted for as held for sale at Dec. 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal in 2016.

Project Development Costs

During 2018, the Corporation wrote-off $23 million in project development costs related to projects that are no longer proceeding.

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.

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, 2018, we provided letters of credit totaling $720 million (2017 - $677 million) and cash collateral of $105 million (2017 - $67 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.

Commitments

Contractual commitments are as follows:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Natural gas, transportation, and other purchase contracts	28	15	13	11	12	157	**236**
Transmission	9	10	6	4	3	—	**32**
Coal supply and mining agreements(1)	158	160	27	24	24	95	**488**
Long-term service agreements	64	86	32	17	8	34	**241**
Non-cancellable operating leases(2)	8	8	8	7	4	45	**80**
Long-term debt(3)	130	486	91	947	141	1,439	**3,234**
Principal payments on finance lease obligations	18	16	9	5	5	10	**63**
Interest on long-term debt and finance lease obligations(4)	161	152	129	123	84	694	**1,343**
Growth	324	79	144	—	—	—	**547**
TransAlta Energy Transition Bill	6	7	6	6	6	—	**31**
Total	**906**	**1,019**	**465**	**1,144**	**287**	**2,474**	**6,295**

(1) Commitments related to Sheerness and Genesee 3 may be impacted by the cessation of coal-fired emissions on or before Dec. 31, 2030.
(2) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.
(3) Excludes impact of derivatives.
(4) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement ("MoA"), we have committed to fund US$55 million in total over the remaining life of the US 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. As at Dec. 31, 2018, the Corporation has funded approximately US$33 million of the commitment.

Contingencies

Line Loss Rule Proceeding

TransAlta has been participating in a line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by TransAlta for its non-PPA MWs. The current estimate of exposure based on known data is $15 million and therefore the Corporation increased the provision from $7.5 million to $15 million in 2018.

FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

Balancing Pool Dispute

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

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 annual audited 2018 consolidated financial statements. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, and other provisions. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our Audit and Risk Committee ("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

Revenue from Contracts with Customers
The Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018. The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are active at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). The Corporation's accounting policies for the current and prior periods for revenue recognition are outlined in Note 2 of the annual audited 2018 consolidated financial statements. The significant judgments and estimates have been highlighted below.

The majority of our revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, renewable attributes and byproducts of power generation. The Corporation evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Corporation's performance to date. The Corporation excludes amounts collected on behalf of third parties from revenue.

Identification of Performance Obligations
Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Corporation's contracts may contain more than one performance obligation.

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

Transaction Price
The Corporation allocates the transaction price in the contract to each performance obligation. Transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Corporation's contracts with customers is primarily variable, and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes which are driven by customer or market demand or by the operational ability of the plant; revenues can be dependent upon the variable cost of producing the energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

In determining the transaction price and estimates of variable consideration, management considers past history of customer usage and capacity requirements, in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of Transaction Price to Performance Obligations
When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Corporation expects to be entitled to in exchange for transferring the good or service.

The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of Performance Obligations
The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient can be relied upon in measuring progress toward complete satisfaction of performance obligations. The invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

The Corporation recognizes a significant financing component where the timing of payment from the customer differs from the Corporation's performance under the contract and where that difference is the result of the Corporation financing the transfer of goods and services.

Revenue from Other Sources
Lease Revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. 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.

Revenue from Derivatives
Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities.

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 described below.

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.

Our Commodity Exposure Management Policy, governs both the commodity transactions undertaken in our proprietary trading business and those undertaken to manage commodity price exposures in our generation business. This 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 for contracts included in the Level III fair value measurements at Dec. 31, 2018, is an estimated total upside of $150 million (2017 - $156 million upside) and total downside of $150 million (2017 - $157 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $116 million upside (2017 - $130 million upside) and $116 million downside (2017 - $130 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$20-US$35 (Dec. 31, 2017 - US$25-US$34) for the period from 2019 to 2025, while the remaining amounts account 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

At the end of each reporting period, we assess whether there is any indication that a PP&E or intangible 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. The 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.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. 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, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. We evaluate the market design, transmission constraints and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. We evaluate synergies with regard to opportunities from combined talent and technology, functional organization, and future growth potential, and we consider our own performance measurement processes in making this determination. No changes arose in our CGUs in 2018.

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. As a result of our review in 2018 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Refer to the Asset Impairment Charges and Reversals section of this MD&A for further details.

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 2018, total depreciation and amortization expense was $710 million (2017 - $708 million, 2016 - $664 million), of which $136 million (2017 - $73 million, 2016 - $63 million) relates to mining equipment and is included in fuel and purchased power.

As a result of the OCA with the Government of Alberta described in the Significant and Subsequent Events section of this MD&A, we will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were reduced to 2030. See the Accounting Changes section of this MD&A for further details.

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.

For purposes of the 2018, 2017 and 2016 annual goodwill impairment reviews, the Corporation determined the recoverable amounts of the CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

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. No reasonably possible change in the assumptions would have resulted in an 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 fulfilment 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 $28 million (2017 - $24 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2018. 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 $501 million (2017 - $549 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2018. 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, 2018, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $407 million (2017 - $437 million). During 2017, mainly as a result of the OCA, the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to use the 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1 billion, which will be incurred between 2019 and 2073. 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	4
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.

Accounting Changes

Current Accounting Changes

IFRS 15 *Revenue from Contracts with Customers*
We adopted IFRS 15 *Revenue from Contracts with Customers* with an initial adoption date of Jan. 1, 2018.

We elected to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the annual audited 2018 consolidated financial statements will not be restated, and comparative period revenues continue to be reported as recognized following IAS 18 *Revenue*. Instead of restating prior years' revenues, we recognized the cumulative impact of the initial application of the standard in the deficit as at Jan. 1, 2018. The cumulative impact of applying the significant financing component requirements of IFRS 15 to an impacted contract resulted in a $13 million (net of tax impacts) increase to the deficit, an increase to the contract liability of $17 million, and a decrease in deferred income tax liabilities of $4 million.

IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer ("significant financing component"). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. We were required to apply this to one of our contracts with a customer. The application of the significant financing component requirements results in the recognition of interest expense over the financing period and a higher amount of revenue.

Additionally, we no longer recognize revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of our gas plants, as it was determined under IFRS 15 that we do not obtain control of the customer-supplied natural gas. This change had no impact on the cumulative impact of initial adoption as recognized in Deficit at Jan. 1, 2018.

Note 2 and Note 3, respectively, of our annual audited 2018 consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 15 and our adoption of IFRS 15.

IFRS 9 *Financial Instruments*
Effective Jan. 1, 2018, we adopted IFRS 9, which introduces new requirements for:

- the classification and measurement of financial assets and financial liabilities;
- the recognition and measurement of impairment of financial assets; and
- a new hedge accounting model.

In accordance with the transition provisions of the standard, we elected to not restate prior periods' comparative financial statements.

Under the new classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or at fair value through other comprehensive income. The classification and measurement depends on the contractual cash flow characteristics of the financial asset and the entity's business model for managing the financial asset. The classification requirements for financial liabilities are largely unchanged. While the Corporation had no direct impact of adoption the IFRS 9 classification and measurement requirements, a $1 million increase in the deficit resulted from the increase in equity attributable to non-controlling interests due to the IFRS 9 classification and measurement impacts at TransAlta Renewables.

IFRS 9 introduces a new impairment model for financial assets measured at amortized cost. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss. The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon application of IFRS 9.

The new general hedge accounting model is intended to be simpler and more closely focused on how an entity manages its risks and introduces new effectiveness testing requirements focused on the principle of an economic relationship and eliminates the requirement for retrospective assessment of hedge effectiveness. The Corporation's qualifying hedging relationships in place as at Jan. 1, 2018, also qualified for hedge accounting in accordance with IFRS 9 and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018.

Note 2 and Note 3, respectively, of our annual audited 2018 consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 9 and our adoption of IFRS 9.

Change in Estimates – Useful Lives

As a result of the OCA with the Government of Alberta described in the Significant and Subsequent Events section of this MD&A, we will cease coal-fired emissions by the end of 2030. On Jan. 1, 2018, the useful lives of some of the Corporation's mine assets were adjusted to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power increased in total by approximately $38 million. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased in total by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to our decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see the Significant and Subsequent Events section of this MD&A for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 was shut down two years early, the Canadian federal Minister of Environment and Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, we extended the life of Sundance Unit 2 to 2021. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, decreased in total by approximately $4 million.

Future Accounting Changes

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

IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. For lessors, the accounting remains essentially unchanged.

IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019. The standard is required to be adopted either retrospectively or using a modified retrospective approach. On transition, TransAlta has elected to apply IFRS 16 using the modified retrospective approach effective Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and low value leases;
- Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;

- Adjusting the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right-of-use assets at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

The Corporation has substantially completed its assessment of existing operating leases. The Corporation estimates that we will recognize right-of-use lease assets and related lease liabilities for existing operating leases where we are the lessee in the range of $42 million to $52 million. These changes will be partially offset by the derecognition of a finance lease asset and a finance lease liability related to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16.

Competitive Forces

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, whereas system capacity, natural gas prices, GHG pricing, government subsidies and renewable resource availability are key drivers to the supply. Growth in behind-the-fence generation for mining investments is key to developing our Australian gas segment.

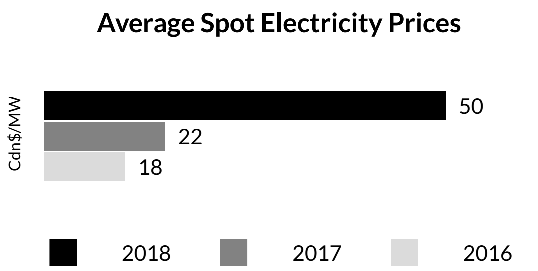
Renewable capacity addition has been strong for the past several years due to government incentives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy as well as natural-gas-fired generation. This expectation is driven by the low prices in the natural gas market combined with public policies that favour carbon emission reductions.

We have substantial merchant capacity in Alberta and the Pacific Northwest. In those regions, we enter into contracts and business relationships with commercial and industrial customers to sell power on a long-term basis, up to our available capacity in the markets. We further reduce the portion of production not sold in advance through short-term physical and financial contracts, and we optimize production in real time against our position and market conditions.

We also compete for long-term contracted opportunities in renewable and gas power generation, including cogeneration, across Canada, the United States and Australia. Our target customers in this area are incumbent utility providers and large industrial and mining operators.

Alberta

Approximately 58 per cent of our gross installed capacity is located in Alberta and approximately 50 per cent of this 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. The Sundance 1 and 2 Alberta PPAs expired at the end of 2017, the Sundance 3 to 6 PPAs were terminated effective March 31, 2018, and the Keephills 1 and 2, Sheerness and Hydro PPAs will expire at the end of 2020. The Balancing Pool acts as buyer for the Keephills and Sheerness PPAs as a result of the terminations in 2016 by the original buyers.



In the fourth quarter of 2017, we announced our strategy of mothballing certain facilities as well as our plan to convert our coal-fired generation to gas-fired generation, and we announced updates to this in December 2018. See the Significant and Subsequent Events section of this MD&A for further details.

Coal generation sold under certain Alberta PPAs retains some exposure to market prices as we 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 ("hydro peaking"). We enter into financial contracts to reduce our exposure to variable power prices for a significant portion of our remaining generation.

Alberta's annual demand increased approximately 3 per cent from 2017 to 2018. The increase in demand was reflected in the average pool price, which increased from $22.19/MWh in 2017 to $50.29/MWh in 2018. The majority of the pool price increase was due to higher carbon compliance costs from thermal generation. The higher prices also positively impacted our merchant wind and hydro portfolio.

Our market share of offer control in Alberta in 2018 was approximately 22 per cent (16 per cent if the Sundance mothballed units are excluded from offer control).

In late November 2016, we announced that we had entered into an OCA with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. We also entered into a Memorandum of Understanding with the Government of Alberta to collaborate and co-operate in the development of a capacity market in Alberta that ensures both current and new electricity generators will have a level economic playing field to build, buy and sell electricity, and to develop a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation.

We expect additional compliance costs as a result of the federal government's proposed framework in which each province is expected to implement a GHG policy equivalent to a carbon price of $50 per tonne by 2022. We believe that our extensive portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro and gas that give us a cost advantage over competitors when constructing generation facilities that use these fuel types.

Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool announced the complete termination of the Sundance 3 to 6 PPAs, effective March 31, 2018. As of April 1, 2018, the Sundance plant has been operated as a merchant facility. There has been no announcement yet concerning the Keephills PPA.

TransAlta continues to operate the Keephills PPA generating units in their ordinary course and receives the capacity and energy payments due to TransAlta under the PPAs.

Coal-to-Gas Conversions

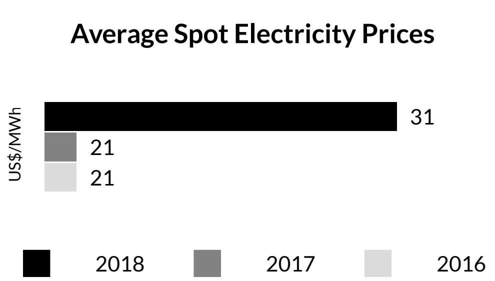
On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity.* The final regulation provides specific provisions for coal-to-gas conversions. The rules for converted units will allow converted plants to operate for a set number of years following the end-of-life for the unit under the coal regulations based on a one-time performance test at the time of conversion.

We are planning the conversion of the units at Sundance and Keephills to gas-fired generation in the 2020 to 2023 time frame. The conversions will provide competitive, reliable, low-cost power to the Alberta market and are expected to position them well in the proposed capacity market. We expect the first capacity auction to occur in 2020 for delivery in November 2021.

In July 2018, we retired the then mothballed Sundance Unit 2 due to its shorter useful life relative to other units, age, size and the capital requirements needed to return the unit to service.

US Pacific Northwest

Our capacity in the US Pacific Northwest is represented by our 1,340 MW Centralia coal plant. Half of the plant capacity is scheduled to retire at the end of 2020 and the other half at the end of 2025. System capacity in the region is primarily comprised of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited and further constrained by emphasis on energy efficiency.



Our coal plant can effectively compete against gas generation, although depressed gas prices following the expansion of shale gas production in North America has added to the downward pressure on power prices.

Our competitiveness is enhanced by our long-term contract with Puget Sound Energy for up to 380 MW over the remaining life of the facility. The contract and our hedges allow us to satisfy power requirements from the market during low-priced periods.

We maintain the right to redevelop Centralia as a gas plant after coal capacity retires, with an opportunity for expedited permitting provided for in our agreement for coal transition established with the State of Washington in 2011.

Contracted Gas and Renewables

The market for developing or acquiring gas and renewable generation facilities is highly competitive in all markets in which we operate. Our solid record as operator and developer supports our competitive position. We expect, where possible, to reduce our cost of capital and improve our competitive profile by using project financing and leveraging the lower cost of capital with TransAlta Renewables. In the United States, our substantial tax attributes further increase our competitiveness.

While depressed commodity prices have reduced sectoral growth in the oil, gas and mining industries, the change is also creating opportunities for us as a service provider as some of our potential customers are more carefully evaluating non-core activities and driving for operational efficiencies. In renewables, we are primarily evaluating greenfield opportunities in Western Canada or acquisitions in other markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities.

Some of our older gas plants are now reaching the end of their original contract life. The plants generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these plants with limited life extending capital expenditures. We have recently extended the life of our Ottawa (2033 expiry), Windsor (2031 expiry), Parkeston (2026 expiry) and Fort Saskatchewan (2030 expiry) plants in this manner.

TransAlta's Capital

The following discusses TransAlta's main categories of capital: Financial, Power-Generating Portfolio, Human, Intellectual, Social and Relationship, and Natural.

Financial Capital

Our goal over the last few years was to build financial flexibility by using multiple sources of funding to reposition our capital structure. Over the last few years, the rating of our unsecured debt was put under pressure by all the rating agencies. We responded to this pressure by taking significant action starting in 2014 to reduce our indebtedness and strengthen our financial metrics.

Moody's lowered the rating of our senior unsecured debt to Ba1 with a stable outlook in December 2015. The direct financial impact of this downgrade has been limited. In June 2018 Moody's revised its rating outlook to positive from stable. During 2018, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a negative outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing. Strengthening the Corporation's financial position allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles. Risks associated with our credit ratings are discussed in the Liquidity Risk section of this MD&A.

Capital Structure

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

As at Dec. 31	2018		2017		2016	
	$	**%**	$	%	$	%
TransAlta Corporation						
Recourse debt - CAD debentures	**647**	**9**	1,046	14	1,045	12
Recourse debt - US senior notes	**943**	**13**	1,499	19	2,151	25
Credit facilities	**174**	**2**	—	—	—	—
US tax equity financing	**28**	**—**	31	—	39	—
Other	**11**	**—**	13	—	15	—
Less: cash and cash equivalents	**(16)**	**—**	(294)	(4)	(290)	(3)
Less: principal portion of restricted cash on TransAlta OCP	**(27)**	**—**	—	—	—	—
Less: fair value asset of economic hedging instruments on debt[1]	**(10)**	**—**	(30)	—	(163)	(2)
Net recourse debt	**1,750**	**24**	2,265	29	2,797	32
Non-recourse debt	**469**	**6**	208	3	245	3
Finance lease obligations	**63**	**1**	69	1	73	1
Total consolidated net debt - TransAlta Corporation	**2,282**	**31**	2,542	33	3,115	36
TransAlta Renewables						
Credit facility	**165**	**2**	27	—	—	—
Less: cash and cash equivalents	**(73)**	**(1)**	(20)	—	(15)	—
Net recourse debt	**92**	**1**	7	—	(15)	—
Non-recourse debt	**767**	**11**	814	11	793	9
Total consolidated net debt - TransAlta Renewables	**859**	**12**	821	11	778	9
Total consolidated net debt	**3,141**	**43**	3,363	44	3,893	45
Non-controlling interests	**1,137**	**16**	1,059	14	1,152	14
Equity attributable to shareholders						
Common shares	**3,059**	**42**	3,094	40	3,094	36
Preferred shares	**942**	**13**	942	12	942	11
Contributed surplus, deficit and accumulated other comprehensive income	**(1,004)**	**(14)**	(710)	(9)	(525)	(6)
Total capital	**7,275**	**100**	7,748	100	8,556	100

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

We continued strengthening our financial position during 2018 and have reduced our total consolidated net debt by almost $800 million since the end of 2016 and enhanced shareholder value by:

2018:

- early redeeming our outstanding 6.650 per cent US$500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million) using proceeds from the Sundance B and C PPAs termination payment and existing liquidity;
- early redeeming our outstanding 6.40 per cent $400 million debentures due Nov. 2019, for approximately $425 million;
- paying out the US$25 million non-recourse debt related to the Mass Solar projects;
- purchasing and cancelling 3,264,500 common shares at an average price of $7.02 per share through our NCIB program, for a total cost of $23 million;

2017:

- making a scheduled US$400 million senior note repayment using existing liquidity. This repayment was hedged with a cross-currency swap entered into on issuance of the debt that effectively reduced our Canadian dollar repayment by approximately $107 million; and
- early redeeming all of Canadian Hydro Developers Inc.'s ("CHD") outstanding non-recourse debentures.

See the Significant and Subsequent Events section of this MD&A for further details.

Throughout 2016, 2017 and 2018, we continued implementing our strategy to raise debt secured by our contracted cash flows and completed the following debt offerings:

- a non-recourse bond in the amount of $345 million on July 20, 2018, with principal and interest payable semi-annually, maturing on Aug. 5, 2030, secured by the payments we receive under the OCA;
- a project-level bond in the amount of $260 million on Oct. 2, 2017, with principal and interest payable quarterly, maturing on Nov. 30, 2033, secured by our Kent Hills wind farm;
- a non-recourse bond in the amount of $202.5 million on Dec. 7, 2016, with principal and interest payable quarterly, maturing on Dec. 31, 2030, secured by our Poplar Creek finance lease contract; and
- a non-recourse bond in the amount of $159 million on June 3, 2016, with principal and interest payable semi-annually, and maturing on June 30, 2032, secured by our New Richmond Wind project in Quebec.

These actions align with our strategy of issuing project-level amortizing debt to proactively manage upcoming debt maturities.

Between 2019 and 2021, we have approximately $707 million of debt maturing. We expect to continue our deleveraging strategy over the next three years as part of our balanced capital allocation plan.

The strengthening of the US dollar has increased our long-term debt balances by $76 million as at Dec. 31, 2018. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

As at Dec. 31	2018	2017
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)(1) and finance lease receivable	**42**	(43)
Foreign currency cash flow hedges on debt	**11**	(45)
Economic hedges and other	**21**	(18)
Unhedged	**2**	(7)
Total	**76**	(113)

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Our credit facilities provide us with significant liquidity. At Dec. 31, 2018, we had $2.0 billion (2017 - $2.0 billion) of committed credit facilities, of which $0.9 billion (2017 - $1.4 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2018, the $1.1 billion (2017 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (2017 - nil) and letters of credit of $0.7 billion (2017 - $0.6 billion). These facilities are comprised of a $1.3 billion committed syndicated bank facility expiring in 2022, TransAlta Renewables $500 million committed syndicated bank credit facility expiring in 2022, and three bilateral credit facilities, totalling $240 million, expiring in 2020.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and OCP non-recourse bonds with a carrying value of $1,235 million (Dec. 31, 2017 - $1,022 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2019. At Dec. 31, 2018, $33 million (Dec. 31, 2017 -$35 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2018.

Working Capital

Including the current portion of long-term debt, the excess of current assets over current liabilities was $439 million as at Dec. 31, 2018 (2017 - $101 million). Our working capital increased year over year mainly due to a decrease in long-term debt due within the next year (last year, we had a US$500 million senior note due). Excluding the current portion of long-term debt of $148 million, the excess of current assets over liabilities was $587 million as at Dec. 31, 2018 (2017 - $848 million), a decrease of $261 million, mainly due to the lower cash and cash equivalents and trade and other receivables.

Share Capital
Our Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares reset in 2016 at a coupon rate of 2.709 per cent. As permitted under the terms of the Preferred Shares, some shareholders elected to convert to a floating rate and 1,824,620 of our 12 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares. Our Series C and Series E Cumulative Redeemable Rate Reset Preferred Shares failed to receive the required number of minimum votes in 2017 to give effect to conversions into Series D and Series F, respectively; accordingly, both the Series C and Series E Preferred Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The Series G preferred shares will reset in 2019.

The following tables outline the common and preferred shares issued and outstanding:

As at	Feb. 26, 2019	Dec. 31, 2018	Dec. 31, 2017
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**284.6**	**284.6**	287.9
Preferred shares			
Series A	10.2	**10.2**	10.2
Series B	1.8	**1.8**	1.8
Series C	11.0	**11.0**	11.0
Series E	9.0	**9.0**	9.0
Series G	6.6	**6.6**	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests
As of Dec. 31, 2018, we own 60.9 per cent (2017 – 64.0 per cent) of TransAlta Renewables. In 2018, our ownership percent decreased due to TransAlta Renewables issuing approximately 12 million common shares under a bought deal offering and approximately one million common shares under their Dividend Reinvestment Plan. We did not participate in either of these issuances.

In 2017, the South Hedland Power Station achieved commercial operation on July 28, 2017, and on Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's common share equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent.

In January 2016, we completed the sale to TransAlta Renewables of an economic interest in the 506 MW Sarnia cogeneration facility and of two renewable energy facilities with total capacity of 105 MW for $540 million. Consideration received from TransAlta Renewables consisted of gross proceeds from a public offering of 17,692,750 common shares at $9.75 per share for gross proceeds of $173 million, 15.6 million common shares of TransAlta Renewables with a value of $152 million, and a $215 million unsecured subordinated debenture convertible into common shares of TransAlta Renewables at a price of $13.16 per common share upon maturity on Dec 31, 2020. On Nov. 9, 2017, TransAlta Renewables paid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. In November 2016, the economic interest was converted to direct ownership of Sarnia, Ragged Chute and Le Nordais by TransAlta Renewables.

TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol "RNW". TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

We remain committed to maintaining our position as the majority shareholder and sponsor of TransAlta Renewables, with a stated goal of maintaining our interest between 60 to 80 per cent.

We also own 50.01 per cent of TA Cogen, which owns, operates or has an interest in three natural-gas-fired facilities and one coal-fired generating facility. In 2016, we recontracted our Mississauga cogeneration, which resulted in a pre-tax gain of approximately $191 million, accelerated depreciation of $46 million and recognized a fuel charge for the de-designation of gas hedges of $14 million. The Mississauga, Ottawa, Windsor and Fort Saskatchewan facilities are owned through our 50.01 per cent interest in TA Cogen. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2018	2017	2016
Interest on debt	**184**	218	218
Interest income	**(11)**	(7)	(2)
Capitalized interest	**(2)**	(9)	(16)
Loss on redemption of bonds	**24**	6	1
Interest on finance lease obligations	**3**	3	3
Credit facility fees, bank charges, and other interest	**13**	18	19
Keephills 1 outage interest accruals (reversals)	**—**	—	(10)
Other[1]	**15**	(3)	(4)
Accretion of provisions	**24**	21	20
Net interest expense	**250**	247	229

(1) During 2018, approximately $5 million of costs were expensed due to project level financing that is no longer practicable and approximately $7 million relates to the significant financing component required under IFRS 15.

Although interest on debt was down due to lower debt levels, net interest expense was higher in 2018 due to the $5 million prepayment premium relating to the early redemption of the US$500 million senior notes, $5 million of costs expensed in connection to a project-level financing that is no longer practicable, the $19 million prepayment premium relating to the early redemption of the $400 million debenture and lower capitalized interest.

Net interest expense increased during 2017 compared to 2016, due to lower capitalized interest and the redemption premium recognized on the early redemption of the CHD debentures, which more than offset higher interest income. During 2016, reversals of interest previously accrued relating to our Keephills 1 outage arbitration reduced interest expense.

Dividends to Shareholders

On Jan. 14, 2016, we announced a reduction of our common share dividend from $0.72 annually to $0.16 annually. This action was taken as part of a plan to improve our long-term financial flexibility. The declaration of dividends is at the discretion of the Board.

The following are the common and preferred shares dividends declared each quarter during 2018:

	Payable date		Common dividends	Preferred Series dividends per share				
Declaration date	Common shares	Preferred shares	per share	A	B	C	E	G
Feb 2, 2018	Apr 1, 2018	Mar 31, 2018	0.04	0.16931	0.17889	0.25169	0.32463	0.33125
Apr 19, 2018	Jul 3, 2018	Jul 3, 2018	0.04	0.16931	0.19951	0.25169	0.32463	0.33125
Jul 19, 2018	Oct 1, 2018	Sept. 30, 2018	0.04	0.16931	0.20984	0.25169	0.32463	0.33125
Oct 10, 2018	Jan 1, 2019	Dec 31, 2018	0.04	0.16931	0.22301	0.25169	0.32463	0.33125
Dec 14, 2018	Apr 1, 2019	Mar 31, 2019	0.04	0.16931	0.23073	0.25169	0.32463	0.33125

Non-Controlling Interests

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2018, increased $66 million to $108 million compared to 2017. Earnings were up at TransAlta Renewables in 2018 due to higher finance income from its investment in the Australian business and the 2017 impairment of an investment. Earnings from TA Cogen were lower in 2018 mainly due to the settlement of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor facilities positively impacting 2017 earnings.

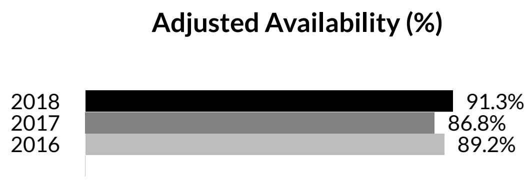
Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2017, decreased by $65 million compared to 2016. Net earnings were negatively impacted by the impairment of TransAlta Renewables' investment in the Australian business recognized as a result of the sale of the Solomon Power Station to FMG and the purported termination of its South Hedland PPA and by higher net interest expense due to higher outstanding borrowings. The Mississauga recontracting has also impacted net earnings, as we recognized a $191 million gain in 2016's results.

Power-Generating Portfolio Capital

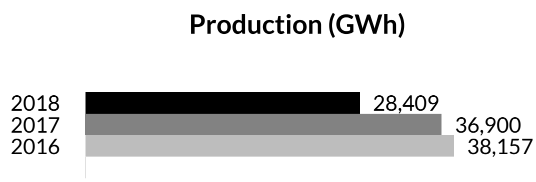
We monitor availability closely as a key metric to achieving our financial targets. We adjust our maintenance and sustaining capital expenditures to optimize financial returns on our investments and to align with our strategic orientations.

Availability and Production

Our availability target for our Canadian Coal fleet was 87 to 89 per cent for 2018. We achieved 93 per cent availability in Canadian Coal. Our availability target for our other generating assets (gas and renewables) was in the range of 95 per cent in 2018. Canadian Gas achieved 93 per cent, Australian Gas 94 per cent and Wind and Solar exceeded 95 per cent at 95.4 per cent.



Our availability for the entire fleet in 2018, after adjusting for dispatch optimization at US Coal, was 91.3 per cent (2017 - 86.8 per cent, 2016 - 89.2 per cent) and was improved over last year. Lower outages and derates at Canadian Coal and higher availability at Canadian Gas due to lower outages were partially offset by the impact of unplanned outages and derates at US Coal in the latter half of the year.



Production for the year ended Dec. 31, 2018, decreased 8,491 GWh compared to 2017. The decrease was mainly at Canadian Coal where production decreased 8,229 GWh primarily due to the mothballing and retirement of certain Sundance units. Production at US Coal was down 104 GWh due to the timing of dispatch optimization. Production at Wind and Solar was also down by 92 GWh mainly due to lower wind resources in Alberta and the United States, partially offset by higher wind resources in Eastern Canada.

Operational

In the generation segments, our 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. In 2017, we initiated Project Greenlight across the entire organization with the intent to deliver committed improvements across the Corporation. Savings achieved in Canadian Coal, Mining and Canadian Gas were offset by increased costs from US Coal and Australian Gas. Increases in OM&A are detailed in the Segmented Comparable Results section of this MD&A.

The following table outlines our generation comparable OM&A over the last three years:

Year ended Dec. 31	2018	2017	2016
Generation comparable OM&A	**405**	412	396
Greenlight transformation costs included in OM&A:			
Canadian Coal	**(6)**	(20)	—
US Coal	**(2)**	(2)	—
Gas, Wind and Solar, and Hydro	**(5)**	(7)	—
Adjusted generation comparable OM&A	**392**	383	396

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. Sustaining capital also includes capital required following the 2013 flood in Alberta, most of which has been recovered from third parties.

Year ended Dec. 31	2018	2017	2016
Routine capital	**50**	69	83
Mine capital	**42**	28	23
Planned major maintenance	**58**	121	148
Finance leases	**18**	17	16
Total sustaining capital expenditures	**168**	235	270
Productivity capital	**21**	24	8
Flood-recovery capital	**—**	—	2
Total sustaining and productivity capital expenditures	**189**	259	280
Insurance recoveries of sustaining capital expenditures	**(7)**	—	(1)
Net amount	**182**	259	279

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

Year ended Dec. 31	2018	2017	2016
GWh lost(1)	**381**	1,234	938

(1) Lost production excludes periods of planned major maintenance at US Coal, which occur during periods of dispatch optimization.

Total sustaining capital expenditures were $67 million lower compared to 2017 and total productivity capital was $3 million lower in 2018 compared to 2017. The productivity capital expenditures relate to the funding of some Project Greenlight transformation initiatives. In certain cases, payback is expected to be achieved within three years. We also completed planned major outages at Genessee Unit 3, Centralia Unit 2 and Sarnia.

Strategic Growth and Corporate Transformation

Acquisition of Two US Wind Projects
On Feb. 20, 2018, TransAlta Renewables announced that it had entered into an arrangement to acquire two wind construction-ready projects in the United States. Construction of the projects has started. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the acquisition to close in early 2019. See the Significant and Subsequent Events section of this MD&A for further details.

Kent Hills Wind Farm
During 2017, TransAlta Renewables entered into a 17-year power purchase agreement with NB Power for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind farm. On Oct. 19, 2018, TransAlta Renewables announced that the expansion is fully operational, bringing total generating capacity of the Kent Hills wind farm to 167 MW.

Pioneer Gas Pipeline Partnership
On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. Tidewater will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline is expected to provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately $90 million. Construction of the pipeline commenced in November 2018 and it is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals.

Windrise Wind Project
On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the two successful projects in the third round of the Renewable Electricity Program. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta. The project is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO and is expected to cost approximately $270 million and is targeted to reach commercial operation during the second quarter of 2021.

Brazeau Hydro Pumped Storage
The Brazeau Hydro Pumped Storage project will generate and support clean electricity in the Province of Alberta. It will store water that can be used to both generate power when it is needed and store excess power supply when demand is low. The Brazeau Hydro Pumped Storage project is a priority for us, as it has existing infrastructure that reduces the cost and environmental footprint of the project, is situated close to existing transmission infrastructure and allows for increased renewables development by balancing intermittent generation from wind and solar.

The Brazeau Hydro Pumped Storage project is expected to have new capacity up to 900 MW, bringing the total Brazeau facility from 755 MW to 1,255 MW, post-completion. We estimate an investment in the range of $1.5 billion to $2.7 billion. During the first nine months of 2018, we invested approximately $2 million to advance the environmental study, work with stakeholders and execute geotechnical work to help further our design and construction phase. Further advancement of the project is dependent on securing a long-term contract.

In May 2018, the AESO released a report stating that dispatchable renewable resources are not needed in the Alberta market before 2030. The value and benefit of the Brazeau Hydro Pumped Storage project would be well beyond the 2030 period. The Corporation still believes that generation from pumped storage should be part of future calls for power under the Alberta Renewables program. The Corporation is not spending additional development dollars on the project at this time but will continue to work with governments to find the appropriate financial mechanisms for bringing low-cost, green, dispatchable renewables into the market to support low prices and emissions for Alberta customers.

Project Greenlight
Project Greenlight is a multi-year program to transform our business and the delivery of the Corporation's strategy. Business units are focusing both on cash flow improvements and the way the Corporation is delivering sustainable value.

Through this program we delivered on projects that improved performance by improving generation efficiency, improving heat rates, lowering fuel costs, reducing GHG emissions, reducing operating and maintenance costs, optimizing our capital spend, avoiding new costs, reducing overhead costs and financing costs, improving working capital, monetizing assets, streamlining processes and achieving efficiencies. Value savings were offset by current year program costs and project costs, made up of mostly capital expenditures. We estimate that the Project Greenlight initiatives generated net $70 million in gross margin, OM&A expense and capital savings. This enabled financial flexibility for new investments. We invested approximately $16 million (2017 - $29 million) in this program and an additional $21 million (2017 - $25 million) in productivity capital in 2018.

Contractual Profile
Approximately 70 per cent of our capacity over the next two years is sold under long-term contracts. Excluding Alberta PPAs for our coal and hydro facilities, the majority of these contracts have maturities in excess of 10 years. During the fourth quarter of 2017, we entered into a long-term contract for the Fort Saskatchewan natural gas facility, commencing Jan. 1, 2020. The contract has an initial 10-year term. In 2016, we entered into a long-term contract for the Akolkolex hydro facility in B.C., expiring in 2045. Our South Hedland Power Station reached commercial operations on July 28, 2017, and is contracted until 2042.

Human Capital

Engaging our workforce, developing our employees and minimizing safety incidents are the keys to human capital value creation at TransAlta. The most material impacts on our human capital performance are having an engaged workforce and keeping our employees safe.

As at Dec. 31, 2018, we had 1,883 (2017 - 2,228) active employees. This number has decreased by fifteen per cent over 2017, following reduction in positions at our coal fleet and restructuring initiatives to reduce costs and increase efficiency. A number of unfilled positions have also been eliminated.

With approximately 50 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith, and we respect the rights of all employees to participate in collective bargaining.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has been cultivated throughout our more than 100-year heritage of pioneering innovative ways to safely and responsibly generate reliable and affordable electricity. In 2016, we formalized our core values to help provide strategic clarity for our employees. We want our people to align with and live our core values, which are: innovation, respect, loyalty, accountability, integrity and safety. We seek to challenge our employees to maximize their potential. We encourage alignment with our values and work ethic, while providing a foundation for leadership, collaboration, community support, growth and work/life balance.

Our organizational structure consists of six levels, which helps facilitate pace and decision-making in our organization. Our business operates as a business-centric model, with Coal & Mining, Gas & Renewables, Australia, and Energy Marketing & Trading defined as our four primary businesses. Our Corporate function oversees our business and provides strategic alignment.

Gender Diversity

A number of case studies have highlighted the link between gender diversity and additional business value. TransAlta is an active supporter of gender diversity as a driver for value, but also as an ethical business practice. Our commitment to increased female participation in our business is evidenced by our female participation rates on both our executive and Board. As at Dec. 31, 2018, women made up 50 per cent of our executive team and 40 per cent of our Board. This is well above our peers in the electricity sector. The Canadian Electricity Association reported that averages for women in executive and on Boards in 2017 was 25.5 and 31.5, per cent respectively. This is also well above the Catalyst Accord, which is signed by a number of leading organizations in Canada, that all support targets to ensure women comprise 30 per cent of executive and Board roles by 2022.

Year ended Dec. 31	**TransAlta (per cent)**	Industry average (per cent)	Catalyst Accord targets (per cent)
Women on executive team	**50**	25	30
Women on Board	**40**	31	30

Employee Benefits

TransAlta is an attractive employer in all three countries in which we operate. We provide compensation to our employees at levels that are competitive in relation to their respective location. We strive to be an employer of choice through our total rewards program, which includes various incentive plans designed to align performance with our annual and mid-term targets, as determined annually by the Board.

Also included in compensation are various retirement savings plans. We have registered pension plans in Canada and the US, as well as a superannuation plan in Australia. The plans cover substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit ("DB") and defined contribution ("DC") options, and in Canada there was an additional DB supplemental pension plan ("SPP") for members whose annual earnings exceeded the Canadian income tax limit. The DB SPP was closed as of Dec. 31, 2015, and a new DC SPP commenced for only executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered in the DB SPP. The Australian superannuation plan is compulsory for employers with contributions required at a rate set by the government, currently 9.5 per cent of employees' wages and salaries.

The Canadian and US defined benefit pension plans are closed to new entrants, with the exception of the Highvale pension plan acquired in 2013. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The defined benefit plans are funded by the Corporation in accordance with governing regulations and actuarial valuations. We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65. The Canadian retiree benefits plan was closed for all new hired employees as of March 1, 2017. The supplemental pension plan is non-registered and an obligation of the Corporation. We are not obligated to fund the supplemental pension plan but are obligated to pay benefits under the terms of the plan as they come due.

Talent and Employee Development

Talent and employee development is viewed as a key pillar of organizational health. In 2018, we extended our Change Leadership Forum to our managers, building upon senior management training in 2017. The two-day session is focused on organizational transformation with an emphasis on identifying root causes of barriers related to driving change.

In 2018, we completed a six-month peer lead leadership training program, called Elevate, for our professionals and subject matter experts. This builds on training of 75 middle management professionals in 2017. The program is focused on establishing a learner's mindset, building trust and influence, strengths-based leadership, being transparent, providing feedback, collaboration as a team and innovation.

In addition to Elevate, we continued our two-day leadership program in 2018 for all of our employees. The program, called Execution Engine, was designed to build capabilities for our people to create an organization that is both efficient and adaptive, while living our values. The training program was built on research into what is needed for our people to help drive and sustain change. To date, approximately 830 employees (or 44 per cent) have taken this course. Employees learn project management (i.e., idea generation, planning, problem solving and prioritization), effective communication (i.e., presentations, meetings and emails), how to get the best out of people (coaching and influencing) and health (organizational health and personal resilience).

In addition, we seek unique ways to expose employees to energy transformation and disruption. Employees are encouraged to target development in areas to support this. In 2018, we sent 25 of our employees to the Energy Disruptors conference in Calgary, which was highlighted by Richard Branson as a keynote. Learning from global leaders working on the energy transition, this group returned to integrate ideas and solutions into our business, through our Project Greenlight program.

Safety

The safety of our people, communities and environment is one of our seven core values. At TransAlta we operate large and complex facilities. The environments in which we work, including Canadian winters and the Australian outback, often add an additional challenge to keep our employees safe. The safety of our staff, contractors and visitors is the top priority of our social performance. Our safety culture is further embedded into TransAlta culture each year. Every meeting of more than four people starts with a "safety moment," which helps share key safety learnings across the Corporation.

Our approach to safety was revised in 2015 when we added to our work on occupational safety with a renewed focus on process safety. In collaboration with ScottishPower, an organization known for achieving leading safety performance, we launched our Total Safety Management System. The management system builds on our occupational safety program, Target Zero, which is focused on protecting our workers on site, through personal protection equipment, inspections, safety controls, job safety analyses, field-level hazard assessments and safety communications. Our Total Safety Management System adds a focus on preventing incidents from our equipment and processes through definition and measurement of safety-critical performance measures and operating limits.

In 2018, the first full year of implementation of a safety culture transformation within our Coal and Mining business was completed. The bulk of the Canadian Coal employees were provided with new tools and capability to improve their own personal safety and that of their workmates. In addition there have been improvements in safety standards, amenities, housekeeping and safety leadership implemented in parallel.

This combination of initiatives has led to progress and results. In 2018 our Injury Frequency Rate ("IFR") was 0.54 (2017 - 0.72). IFR is defined as the number of injuries (lost-time and medical) for every 200,000 hours worked. Our ultimate goal is to achieve zero injury incidents, but annually we seek improvement over the prior year. Our target IFR in 2019 is 0.43, a 20 per cent reduction over 2018 performance.

In 2017, we introduced a new key performance indicator to help us further improve our safety performance. Total Incident Frequency ("TIF") tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids) relative to employee hours worked. First aids can be minor (such as a cut or scratch); nevertheless, incident awareness and understanding provide us with preventative safety knowledge, which translates into education for employees and injury avoidance. Our TIF in 2018 was 1.98, which was a 44 per cent improvement over 2017 performance. We are targeting a TIF of 1.58 in 2019, a 20 per cent reduction over 2017 performance. As noted above, our long-term goal is zero.

Year ended Dec. 31	**2018**	2017	2016
IFR	**0.54**	0.72	0.85
TIF	**1.98**	3.54	—

On December 29, 2018, we were notified of an incident that occurred and resulted in the fatality of an employee of Coalview Centralia LLC, which operates a fine coal recovery project within the Centralia mine site. Coalview Centralia LLC is a company that provides reclamation services to TransAlta and is not otherwise affiliated with the Corporation. We are all deeply saddened by this situation and our thoughts and prayers are with the families, co-workers and friends impacted. Safety is an integral value at TransAlta and we continue to work every day to make our work environments safe.

We reward our business units for safety leadership annually at our President's Awards. This year the award for Safety Leadership and Performance was given to our Hydro fleet for achieving target zero in 2018. No medical aids and injuries occurred in 2018, despite 145,000 exposure hours while operating 27 facilities. It was a fantastic achievement from our Hydro business unit and provides inspiration for our other business units.

Intellectual Capital

At TransAlta we define intellectual capital as our knowledge-based assets. Measuring these assets serves two purposes. First, we seek to understand our knowledge-based assets to improve our management and performance of these assets. Second, we seek to understand these assets to communicate their real value. The following highlights some of our knowledge-based assets, which we believe provide us with a competitive edge and that contribute to shareholder value.

Brand Recognition
Our employee culture is supported by a purpose-based, long-term and sustainable business strategy, which is growth in affordable and clean power generation. TransAlta has operated power generation assets for over 100 years, which reflects this approach to long-term and sustainable business. A long-term commitment to business and partnerships lends itself to goodwill and brand recognition, something we value and don't take for granted. We believe our low-cost and clean power strategy, supported by our internal values and sustainable approach to business, will help support and continue to increase our brand recognition positively.

Diversified Knowledge
The experience and acumen of our employees further enhances our capital value creation. Our business has been operating for over 100 years, and many of our employees have been with us for 30 plus years.

Our experience in developing and operating power generation technologies is highlighted below. The transition of our coal assets to natural gas is a natural fit with our operating experience. Relative to coal, gas operations have lower operating costs, have increased operating reliability and flexibility, require less manpower and reduce GHG and air emissions. Our trading and marketing business complements our knowledge of operating power generation assets.

Power generation type	Operating experience (years)
Hydro	107
Natural Gas	68
Coal	68
Wind	16
Solar	3

Innovation: Idea Generation and Project Management
We believe that global marketplace disruption is a new normal and we recognize that to adapt to the pace of change and remain competitive, our employees and processes must be nimble, adaptive and supporting working more efficiently, while at speed. For further details on our investment in our workforce, please see the Talent and Employee Development discussion in the Human Capital subsection of this MD&A.

This is evidenced by our ongoing internal transformation, called Project Greenlight, which is entering its third year since implementation. This project is focused on bottom-up innovation, specifically fostering a culture of idea generation, development of ideas into projects with defined KPIs, milestones and execution or delivery dates, and ongoing project management to ensure success. Where we fail, we idea generate, build and test again. Since inception, we have spent considerable time educating and training our employees to both think differently and then manage their business case from idea to delivering sustained value. Year three is the final year of the project and we plan to transition Project Greenlight into the business as a sustained process.

For further details on our investment in our workforce, please see the Talent and Employee Development discussion in the Human Capital subsection of this MD&A.

Innovation: Applied Technologies

TransAlta has been at the forefront of innovation in the power generation sector since the early 1900s when we developed hydro assets. To add context, these assets were developed at the same time as the automobile. We have been an early adopter and developer of wind technology in Canada and are now one of the largest wind generators in the country. Today we run a Wind Control Centre, the only one of its kind in Canada, that monitors, to the second, each and every wind turbine we operate across North America. In 2015, we made our first investment in solar technology with the purchase of a 21 MW solar facility in Massachusetts.

As we move towards our vision of becoming the leading clean power corporation in Canada by 2025, we continue to seek solutions to innovate and create value for investors, society and the environment. This is evidenced by our announcements of the accelerated coal-to-gas conversion plans, the expansion of our Kent Hills wind farm in New Brunswick, the 90 MW Big Level and 29 MW Antrim wind development projects in the US, the 207 MW Windrise wind development project in Alberta, proposed solar development on our reclaimed mine site at our Centralia facility in Washington State, and the exploration of hydro expansion.

We are keeping up to date with power technologies that have the potential to redefine power markets today and in the future. Innovation is constantly happening on a more micro scale at TransAlta. For more information on innovation at TransAlta, please visit www.transalta.com/about-us/innovation.

In addition, our teams continuously explore the use of applied or new technologies to find solutions to expand or adapt our fleet in an ever-changing world, which helps protect our shareholder value and maintain delivery of reliable and affordable electricity. The following are further examples of how we have developed innovative solutions to optimize and maximize value from our fleet:

Operations Diagnostic Centre

TransAlta has run its Operations Diagnostic Centre ("ODC") since 2008. The ODC monitors coal-fired, gas-fired and wind-generating assets across Canada, the United States and Australia. A centralized team of engineers and operations specialists remotely monitors our power plants for emerging equipment reliability and performance issues. ODC staff are trained in the development and use of specialized equipment monitoring software and can apply their experience in power plant operations. If an equipment issue is detected, the ODC notifies plant operations to investigate and remedy the issue before there is an impact to operations. The monitoring, analysis and diagnostics completed by the ODC are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day plant operations.

Operational Integrity Program

Our Operational Integrity program is the integration of sustainability, specifically safety, into asset management. It is a program designed to achieve process and equipment safety by understanding and monitoring key operational risks and implementing mitigation measures. Consider it proactive safety. In 2017, we put into place our Total Safety Management System, which integrates our work in process safety with our existing strength in occupational safety programs. We continue to see a positive increase in self-reporting and addressing process safety hazards as awareness and new tools are being introduced. This is evidenced by our trend in safety incidents, which decreased in 2018 to an IFR of 0.54 (2017 - 0.72). This was one of our best safety performance years in our history. Our goal is zero and the Operational Integrity program is a tried and tested tool to help propel us closer to this goal.

Social and Relationship Capital

Creating shared value for our stakeholders is the key to social and relationship value creation at TransAlta. The most material impacts on our social and relationship performance are public health and safety, anti-competitive behaviour and fostering better relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners where we operate.

Public Health and Safety

We seek to ensure public health and safety through measures that include restricting physical access to our operating sites and minimizing our environmental impact. It is our goal to keep safe our employees and the peoples and communities where we operate.

We specifically look to minimize the following risks:

- harm to person(s),
- damage to property,
- increased liability due to negligence, and
- loss of organizational reputation and integrity.

We actively monitor air emissions from our coal and gas plants. Our large coal facilities have Continuous Emissions Monitoring Systems in place, which help us monitor our pollutant emission levels to ensure they are in line with acceptable limits. When we are in breach of regulatory limits we report this to regulatory bodies and conduct a root cause analysis to understand how we can eliminate future breaches from occurring. In 2018, we had two mercury exceedance events at our Centralia coal plant and one NOx stack breach at our Sundance facility. All of the events were captured through our monitoring systems and resolved quickly as a result. These incidents were all reported to regulatory bodies and were deemed to be minor.

Of note, our coal plants currently capture 80 per cent of mercury emissions and the majority of particulate matter emissions. Both mercury and particulate matter emissions have been deemed harmful to human health, which we recognize and work to minimize through capture. The health impact risk from emissions that do reach our environment is minimized due to the location of our plants, which are located away from urban environments. Independent studies dated Nov. 19, 2015, and conducted by University of Alberta scientist Dr. Warren Kindzierski, using provincial government monitoring data over nine years, also show that approximately 10 per cent or less of all particulate matter in the airshed in the largest urban environment close to our facilities, Edmonton, can be attributed to coal combustion emissions. Chemical "signatures" for emissions pointed to several sources of air quality concern in Edmonton, including local industry, vehicles and wood-burning fireplaces.

Assuming reasonably anticipated growth and operating scenarios, we expect future GHG emissions and air pollution emissions performance will be dramatically reduced in respect of our existing assets as we execute our coal-to-gas conversion strategy. GHG emissions from coal are expected to be cut within the range of 60 per cent or 12 million tonnes carbon dioxide equivalent (CO_2e). We currently capture 80 per cent of mercury emissions at our coal plants and mercury emissions will be eliminated following the coal-to-gas conversion. Particulate matter and sulphur dioxide emissions will be virtually eliminated or considered negligible post-coal-to-gas conversion and diesel burn. Our nitrogen dioxide emissions will also be reduced in the range of approximately 50 per cent.

Indigenous Relationships and Partnerships

The focus of our efforts in this area is to fulfill TransAlta's principles for engagement and ensure we live up to its commitments with Indigenous neighbours. Efforts are focused on building and maintaining solid relationships and establishing strong communication channels that enable TransAlta to share information on operations and growth initiatives, gather feedback to inform project planning and understand priorities and interests to better address concerns.

Specifically, our Aboriginal Relations team continues to develop and enhance aboriginal relations in areas of employment, economic development, community engagement, and investment.

Each year, TransAlta provides seven $3,000 bursaries for post-secondary and three $1,000 bursaries for trades students to support the success of Indigenous students in their educational programs. TransAlta's criteria for accessing the bursary includes any educational pursuit that will support the wellbeing of Indigenous peoples and communities. The bursary is open to all Indigenous applicants that have completed high school. Through agreements and ongoing relationship commitments TransAlta makes information on employment positions available to Indigenous communities and provides sub-contractors terms and conditions to include Indigenous content considerations for procurement initiatives.

In 2017, we once again achieved the Canadian Council for Aboriginal Business's silver-level Progressive Aboriginal Relations (PAR) certification. Certification occurs ever three years. In 2016, we introduced our STAR tracking program, which functions as a communication record-keeping and engagement measurement tool. This capacity fulfills our requirements for consultation with stakeholders and aboriginal groups alike, and is capable of producing reports (notably, government reports) as proof of engagement and consultation efforts.

In 2018, to further support access to education TransAlta created an Indigenous Gap program with the Southern Alberta Institute of Technology (SAIT) to provide support to Indigenous students who need high school upgrading in order to enter a trade program.

In 2017, we supported an Indigenous Leadership Program at Banff Centre for Arts and Creativity. Approximately 250 Indigenous leaders from over 120 communities attended the leadership programs with help from TransAlta and other supporters.

Over the past five years, TransAlta's support has provided 39 scholarships for members of Indigenous communities to attend the programs and take that learning back to their communities. Those participants have come from communities across Alberta and British Columbia including the First Nations of Alexis Nakota Sioux, Bearspaw, Chiniki, Enoch Cree, Ermineskin Cree, Fort McKay, Kainai, Montana, Paul, Piikani, Samson Cree, Siksika, Squamish, Tsuu T'ina, and Wesley.

Stakeholder Relationships
Relationships matter to TransAlta. Driven by our values, we seek to maximize value creation for our stakeholders and TransAlta.

TransAlta Stakeholders
Regardless of who our stakeholders are or who they represent, our goal is to act in the best interests of the Corporation and to create either financial, environmental or social value for both our stakeholders and TransAlta. Major stakeholder categories can be summarized as shareholders, debt holders, business partners, contractors, consultants, customers, community organizations, employees, governments, Indigenous groups, industry and professional bodies, media, NGOs, public and regulatory affairs, residents and suppliers. This too encompasses our value chain. Our mindset is value creation across this chain through the development of relationships and partnerships.

Engagement Framework
Our stakeholder engagement framework is modelled and closely tied to the stakeholder engagement aspect of ISO 14001, which is an internationally recognized environmental management standard. This framework is a streamlined corporate-wide approach to ensure that engagement and relationship-building practices are consistent across TransAlta's locations and types of work.

Methods of Engagement
In order to run our business successfully, we are in consistent two-way communication with the majority of our stakeholders, some more than others. As an example, our dialogue with customers is daily, iterative and takes on many forms including meetings (in-person, virtual, and one-one), calls, emails, newsletters and feedback systems (online loops). It is both proactive and reactive. Our approach and our goal is to be proactive, which is communicating consistent messaging and information, while being transparent. There are often times we will need to be reactive, such as to a customer complaint, and we commit to timely and professional resolution using values-based dialogue. We then work to identify how to mitigate further issues, moving back to our proactive approach.

Part of our business is growth, which we achieve by developing or purchasing new assets. We proactively engage with many stakeholders in all of our geographic operating areas in Australia, Canada and the United States in order to develop and maintain relationships; assess needs and fit; and to seek out collaborative and sustainable value creation opportunities.

Recently we completed construction of our South Hedland 150 MW combined-cycle plant in Western Australia. The project took four years from RFP to commercial operation. Achieving construction and commercial operation was the outcome of successful stakeholder engagement and collaboration. We recently announced our coal-to-gas transition plan, secured by way of collaborative stakeholder engagement. This plan involved signing a Memorandum of Understanding with the Alberta government, which highlights the project fit for Alberta, not just TransAlta. The coal-to-gas project is expected to significantly reduce the environmental impact from coal (a reduction in air pollution and GHG emissions) while enabling the transition and addition of 5,000 MW of renewable energy by 2030.

More details on our stakeholder engagement activities can be found via our social media channels.

Engagement Tracking and Reporting
Our Stakeholder and Indigenous Relations tracking program functions as a Corporation-wide communication record-keeping tool, which is managed by our Stakeholder and Indigenous Relations team. This capacity fulfills our requirements for consultation with stakeholders and aboriginal groups alike, and is capable of producing reports (notably, government reports) as proof of engagement and consultation efforts. Built as an in-house application, this tool has no operating cost or fees and has the ability to grant different levels of access to information. Furthermore, the tool can store email conversations, documents and voice-mail messages related to any project, event or issue, and use them in reports. It can also produce an array of statistical reports showing frequencies and volumes of engagement based on project, stakeholder, stakeholder group, issue or keywords.

Engagement and Board Communication
The Board believes that it is important to have constructive engagement with its shareholders and other stakeholders and has established means for the shareholders of the Corporation and other stakeholders to communicate with the Board. For example, employees and other stakeholders may communicate with the Board, through the Audit and Risk Committee ("ARC"), by writing to the ARC; employees and other stakeholders may also communicate with the Board, through the ARC, by making submissions via the Corporation's toll-free telephone or online Ethic Helpline (see the Whistleblower System below for more details). Shareholders are also invited to communicate directly with the Board under the Corporation's Shareholder Engagement Policy, which outlines the Corporation's approach to proactive director-shareholder engagement at and in between the Corporation's annual shareholders meetings. Under the Shareholder Engagement Policy, shareholders can request meetings with members of the Board and can submit questions or inquiries to the Board, which the Corporation will respond to. A copy of the Shareholder Engagement Policy is available on our website at https://www.transalta.com/about-us/governance/shareholder-engagement-policy/. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. In addition, the Board has adopted an annual non-binding advisory vote on the Corporation's approach to executive compensation (say-on-pay). The Corporation is committed to ensuring continued good relations and communications with its shareholders and other stakeholders and regularly evaluates its practices in light of any new governance initiatives or developments in order to maintain sound corporate governance practices.

Customers
In early 2018 we launched our new energy services for customers. Our customer solutions team has partnered with best-in-class energy service providers to help businesses achieve:
- energy consumption and energy cost management;
- market price risks and volume exposure mitigation;
- sustainability initiatives such as self-generated electricity; and
- monitoring of energy market design changes, price signals and applicable and available incentives.

Our energy services include solar, energy-efficiency audits, distributed generation and building automation. To learn more, please visit the Energy Services customer page on our website at https://www.transalta.com/customers/.

Supply Chain
We continue to seek solutions to advance supply chain sustainability. In 2017 we partnered with Ivalua Inc. to optimize our global supply chain management operations. After an exhaustive review of all leading vendors, Ivalua was selected for its comprehensive Source-to-Pay platform, flexible architecture and overall ability to give TransAlta a competitive advantage. Key business values that we expect include increased supply chain efficiency, reduced lead times, lower costs and improved supplier performance.

We continue to offer our business units optional sustainability terms and conditions for inclusion within supplier agreements. These terms and conditions include suppliers communicating their sustainability policies, strategy and performance; documented systems for labour practices; environmental management systems; disclosure of environmental infringements; disclosure of anti-competitive behaviour; disclosure on climate change management; third-party certifications on products; and demonstration of community investments. Furthermore, as we explore major projects, we are assessing vendors both at the RFP evaluation stage and in up-front information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example, getting information on:
- estimated value of services that will be procured though local Indigenous businesses (in RFP template);
- estimated number of local Indigenous persons that will be employed (in RFP template);
- understanding overall community spend and engagement; and
- understanding through interview processes and stakeholder work the state of community relations.

In addition, in early 2019, the Board of Directors adopted a Supplier Code of Conduct that applies to all vendors and suppliers of TransAlta. Under the Code, suppliers of goods and services to TransAlta are required to adhere to our core values, including as it pertains to health and safety, ethical business conduct and environmental leadership. The Code also allows suppliers to report ethical or legal concerns related to the Code via TransAlta's Ethics Helpline.

Local Communities
TransAlta creates value for local communities through the generation of an essential service. We provide reliable, cost-efficient and clean power in Australia, Canada and the United States.

With the phase-out of coal, communities surrounding our plants will be impacted as our workforce will substantially decline. However, our proposed coal-to-gas conversions provide the opportunity to maintain some jobs at the power plants for substantially longer than would have been possible if the plants continued to only burn coal. Electricity and energy have always been at the heart of the economy in Alberta, and any changes in the industry must therefore support our communities. Conversion will also help keep municipal, provincial and federal tax revenues supporting these communities. TransAlta advocates for a smart and long-term energy transition in Alberta to minimize disruption and negative economic impact, and to provide support for facility redevelopment, funds for retraining and economic diversification in the province.

Community Investments
During 2018, TransAlta contributed $2.4 million in donations and sponsorships (2017 - $2.6 million). One of our major community investments is to United Way campaigns across Canada and the US. This year, TransAlta employees, retirees, contractors and the Corporation raised over $1.1 million for the United Way.

In 2018, we had a focus on youth education and achieved our target to direct $0.75 million of community investment to this cause. Some of our partnerships included the University of Calgary, Southern and Northern Alberta Institutes of Technology, Mount Royal University, Banff Centre for Arts and Creativity (Indigenous leadership scholarships), Mother Earth Children's Charter School (Indigenous kindergarten to Grade 9), Calgary Stampede (The Young Canadians - ages seven to 18), national Canada and US Indigenous scholarships (post-secondary for trades and academic) and the Alberta Council for Environmental Education.

On July 30, 2015, we announced a US$55 million community investment over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The US$55 million community investment is part of the TransAlta Energy Transition Bill, passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State by closing the Centralia facility's two units, one in 2020 and the other in 2025. In order to invest the $55 million, three funding boards were formed: The Weatherization Board ($10 million), the Economic & Community Development Board ($20 million) and the Energy Technology Board ($25 million). To date, the Weatherization Board has invested $5.9 million, the Economic & Community Development Board $12 million and the Energy Technology Board $3.9 million.

Natural Capital

We continue to increase financial value from natural or environmental capital-related business activities, while reducing our carbon footprint. Comparable EBITDA from renewable energy generation in 2018 was $322 million (2017 - $289 million). Our revenue in 2018 from carbon-related offsets was $21.6 million (2017 - $27.7 million). In addition, in 2018 the sale of coal byproducts and waste-related recycling generated financial value in the range of $25 million to $35 million.

The following are key natural capital KPI trends:

Year ended Dec. 31	2018	2017	2016
Renewable energy comparable EBITDA	**322.0**	289.0	277.0
Carbon offsets revenue	**21.6**	27.7	29.0
GHG emissions (million tonnes CO_2e)	**20.8**	29.9	30.7

Natural Capital Management
All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in renewable energy resources such as wind, hydro and solar, we also believe that natural gas will continue to play an important role in meeting energy needs as part of a clean energy transition. We are planning the conversion of our Alberta coal units to natural gas in the 2020 to 2023 time frame.

Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost electricity. Currently the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (pollutants, metals), and energy use. Other material impacts that we manage and track performance on includes our environmental management systems, environmental incidents and spills, land use, water usage and waste management.

We maintain procedures for environmental incidents similar to our safety practices, with tracking, analyzing and active management to eliminate occurrence, and ongoing support from our Operational Integrity program. With respect to biodiversity management, we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities and closely monitor the air, land and water in these areas to identify and curtail potential impacts.

Environmental Performance
Reducing the environmental impact of our activities benefits not only our operations and financial results, but also 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 with respect to the Corporation's monitoring of environmental regulations and public policy changes and to the establishment and adherence to environmental practices, procedures and polices in response to legal/regulatory and industry compliance or best practices.

Our performance on managing environmental impacts, reducing our environmental impact and capitalizing on environmental initiatives includes the following.

Renewable Energy
Over the last 10 years, we have added approximately 1,200 MW in renewable energy capacity. Over 1,000 MW has been wind energy development and today we are positioned as an industry leader in wind energy. We continue to operate over 900 MW of hydro energy and our experience with hydro operations is over 100 years. In 2015 we made our first solar investment, 21 MW in Massachusetts, and we continue to look for opportunities to develop and operate solar energy. Our production from renewable energy in 2018 offset the equivalent of approximately 2.9 million tonnes of CO_2e or the removal of approximately 620,000 cars from the roads in 2018.

Carbon Offsets
In 2018, 200 MW of our Alberta wind capacity was eligible to generate offsets at a rate of $30 tonne CO_2e. Annual revenue generation from these offsets was in the range of $10 million to $15 million. In 2019, as per rules associated with the new Alberta *Carbon Competitiveness Incentive Regulation*, our offset eligibility capacity will expand to include additional capacity from our wind fleet and hydro fleet. As a result we anticipate offset revenue to rise to approximately $25 million in 2019.

Coal Transition
Our coal-to-gas conversion plan in Alberta is expected to vastly improve our environmental performance. Energy use, GHG emissions, air emissions, waste generation and water usage is expected to significantly decline. A conversion of coal-fired power generation to gas-fired generation is expected to eliminate all mercury emissions, the majority of sulphur dioxide emissions ("SO_2") and significantly reduce our nitrogen dioxide emissions ("NO_X").

Environmental Management Systems
All of our 73 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely align with the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for 19 years, and our systems and knowledge of management systems are therefore mature. We no longer certify our Alberta coal plants as ISO 14001, but the plants continue to run best practice EMS. Only two of our facilities do not closely track ISO 14001, which is due to commercial arrangements (we are not the primary operator), but these facilities still have EMS.

Environmental Incidents and Spills
We recorded seven significant environmental incidents in 2018 (2017 - five incidents), which was below our target of nine. We categorize significant as violations or non-compliance to regulations or exceedance of limits in company operating approvals that resulted in or had the potential to result in enforcement action. This was another year of excellent performance that reflects our continuous improvement in tracking, reporting and identifying potential hazards. Five of our incidents occurred at our coal facilities and two incidents occurred at our gas facilities. None of these incidents resulted in a material environmental impact.

The following are the environmental incidents by fuel types:

Year ended Dec. 31	2018	2017	2016
Coal	**5**	5	13
Gas and renewables	**2**	—	3
Total environmental incidents	**7**	5	16

Incident types in 2018 were primarily regulatory in nature, whereby we had minor infringements on set regulatory requirements. These included two mercury exceedances at our Centralia coal facility, a nitrogen dioxide stack exceedance at our Sundance coal facility, failure to properly notify the regulator of un-salvaged topsoil, per EPEA Approval Condition 3.2.1, at our Sunhills mine, and a pH exceedance on an oil/water separator at our Sarnia gas facility. We also had two releases, one liquid and one gas. These included a secondary mine drainage water excursion from our Sunhills mine and a refrigerant release at our Ottawa gas facility. All incidents were managed in line with our EMS practice and resolved quickly. We continue to target improvement and our corporate-wide 2019 target is five or fewer incidents. We also continue to track and manage all non-reportable (minor) environmental incidents, which helps us identify what causes an incident. Understanding the root cause of incidents helps with incident prevention planning and education.

Typical spills at TransAlta are hydrocarbon spills, which happen in low environmental impact areas and are almost always contained and recovered. It is extremely rare that we experience large spills with impact on the environment. Spills that do occur that we must report are typically just above acceptable regulatory spill limits and these are always addressed with a critical time factor. The estimated volume of spills in 2018 was 5 m^3 (2017 - 15 m^3).

Air Emissions

Air emissions in 2018 decreased significantly compared with 2017 levels. The reduction was due to a significant reduction in coal power generation from our Sundance coal facility and increased generation from co-firing with gas at our merchant facilities. SO_2 emissions decreased by 47 per cent, NOx emissions decreased by 37 per cent, particulate matter emissions decreased by 62 per cent and mercury emissions decreased by 41 per cent. These reductions highlight our commentary in our 2017 annual integrated report, which noted that we will dramatically reduce air emissions through our planned conversion of two coal units at Sundance, Alberta and the three coal units at Keephills, Alberta to gas-fired generation in the 2020 to 2023 time frame.

We continue to capture 80 per cent of mercury emissions at our coal plants and by 2025 our post-coal era, mercury emissions will be eliminated. Particulate matter and SO_2 emissions will also be virtually eliminated or considered negligible post-coal power generation. NOx emissions will also be reduced to levels under 20,000 tonnes annually.

We are well underway and remain on track to achieve our target of 95 per cent SO_2 emission reductions by 2030. Since 2005, we have reduced SO_2 emissions by 72 per cent. As noted above, we are on track to achieve our SO_2 target by 2025, well ahead of our 2030 goal. In 2018 we revised our NOx reduction target to 2030 from 95 per cent to 50 per cent. This allows flexibility as we convert coal facilities to natural gas and expand our natural gas fleet.

Year ended Dec. 31	2018	2017	2016
Sulphur dioxide (tonnes)	**19,300**	36,200	39,600
Nitrogen dioxide (tonnes)	**28,000**	44,400	48,400
Particulate matter (tonnes)	**7,800**	14,500	13,800
Mercury (kilograms)	**70**	110	130

Water

Our principal water uses are for cooling and steam generation in coal and gas plants, and for hydro power production. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2018 we withdrew 245 million m^3 and returned approximately 208 million m^3 back to its source. Water is withdrawn primarily from rivers where we hold permits to withdraw water and adhere to regulations on water quality. We return or discharge approximately 70 per cent of water back to the source, meeting the regulatory quality levels that exist in the various locations in which we operate. The difference between withdraw and discharge, representing consumption, is largely due to evaporation loss.

The following represents our total water consumption (million m^3) over the last three years:

Year ended Dec. 31	2018	2017	2016
Water from environment	**245**	213	239
Water to environment	**208**	172	197
Total water consumption	**37**	41	42

Our areas of higher water risk are situated east of Perth in our simple-cycle gas plants in Western Australia and in our southern Alberta hydro operations. We monitor and manage water risk in our operating areas east of Perth. In southern Alberta, following the flood of 2013, our hydro facilities are being used for a greater water management role than they have played in the past. In 2016, we signed a five-year agreement with the Government of Alberta to manage water on the Bow River at our Ghost reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis Lakes System (which includes Interlakes, Pocaterra and Barrier) for drought mitigation efforts.

Land Use

The largest land use associated with our operations is for surface mining of coal. Of the three mines we have operated, the Whitewood mine in Alberta is completely reclaimed and the land certification process is ongoing. Our Centralia mine in Washington State is currently in the reclamation phase (35 per cent reclaimed), and our Highvale mine in Alberta is actively mined with certain sections undergoing reclamation. Our reclamation plans are set out on a life-cycle basis and include contouring disturbed areas, re-establishing drainage, replacing topsoil and subsoil, re-vegetation and land management. Our mining practice incorporates progressive reclamation where the final end use of the land is considered at all stages of planning and development.

In 2018, we reclaimed 28 acres (11 hectares) at our Highvale mine, which was below our target of 74 acres (30 hectares). This was due to weather conditions limiting the amount of final placement of topsoil. Topsoil placement is the final stage of reclamation. We reallocated resources to other stages of reclamation (such as ground leveling) to move us closer to final reclamation in following years, which keeps us on track with our long-range reclamation plan. The Centralia mine is no longer actively used for coal operations, but reclamation activity is ongoing. In 2018 we reclaimed 113 acres (46 hectares) of land. Since 1991, over 3,000 acres have been reclaimed and approximately 1.7 million seedlings have been planted as part of the reclamation work.

In 2016, we decommissioned our Cowley Ridge wind plant, which was Canada's first commercial wind plant when it was constructed in 1993 and reached its end of life in 2016. During this process, our wind operations team recycled:

- 54 towers weighing over 9,000 kilograms ("kg");
- 61 nacelles, which is the housing of the turbine generating components, weighing 10,000 kg;
- 19 transformers weighing over 4,000 kg; and
- 32,000 litres of oil.

Our recycling efforts meant that we diverted close to 1,200,000 kg from the land fill. This job was completed safely, and in addition generated around $0.15 million of value from the recycled components. This work reflects TransAlta's values of innovation and safety, while maintaining a positive environmental impact at our operations.

Waste

In 2018 our operations generated approximately 1.3 million tonnes of waste. Waste volumes are all primarily non-hazardous. Only 0.1 per cent of waste volumes are hazardous materials. In 2018, only 0.1 per cent of waste was directed to landfill. From the remaining 99.9 per cent, 56 per cent was returned to the mine (ash from coal combustion), 43 per cent was reused and the remaining 0.3 per cent was recycled.

Our reuse waste or byproduct waste is resold in to markets. Byproduct sales and associated annual revenue generation typically ranges from $25 million to $35 million. Our operating teams are diligent at not only minimizing waste, but also maximizing recoverable value from waste. Over the years, we have invested in equipment to capture byproducts from the combustion of coal, such as fly ash, bottom ash, gypsum and cenospheres, for subsequent sale. These non-hazardous materials add value to products like cement and asphalt, wallboard, paints and plastics.

Energy Use

TransAlta uses energy in a number of different ways. We burn coal, gas and diesel to generate electricity. We harness the kinetic energy of water and wind to generate electricity. We also use the sun to generate electricity. In addition to combustion of fuel sources we also track combustion of fuel in the vehicles we use and energy use in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies. As an energy corporation, we naturally look for ways to optimize or create efficiencies related to the use of energy. Our coal-to-gas conversions display one innovative way we intend to reduce a significant amount of energy use and significantly reduce our environmental impact, while returning the generation of reliable and low-cost power supply to Albertan customers.

The following captures our energy use (millions of gigajoules). On a comparable basis, our energy use declined by 30 per cent over 2017 as a result of coal retirements and reduced coal generation from our Sundance facility. Our coal-to-gas conversions will significantly reduce our energy usage as gas uses less energy for generation of a MWh.

Year ended Dec. 31	**2018**	2017	2016
Coal	**309.8**	447.4	469.1
Gas and renewables	**48.6**	49.4	59.2
Corporate	**0.1**	0.1	0.1
Total energy use	**358.5**	496.9	528.4

Weather
Abnormal weather events can impact our operations and give rise to risks. In addition, normal year-over-year variations in wind, solar, water and temperatures give rise to various levels of volume risk depending on the input fuel of each facility; events outside the design parameters of our facilities give rise to equipment risk; and fluctuations in temperatures can cause commodity price risk through impact on customer demand for heating or cooling. Refer to the Governance and Risk Management section of this MD&A for further discussion of each risk and our related management strategy.

During the past five years, some deviations from expected weather patterns have negatively impacted our annual financial results:
- the southern Alberta flood of 2013 disrupted our hydro operations and caused us to invest in substantial repair work. Our losses have been largely covered through insurance;
- warm weather in Alberta in 2015 increased derates at our coal facilities due to its impact on the Sundance cooling ponds. These cooling ponds are susceptible to warm weather; however, we anticipate that decreased coal production from the retirement of Sundance Units 1 and 2, respectively, in the medium term will reduce the stress from such occurrence; and
- our Alberta mine was susceptible to significant rain starting in August 2016, which resulted in several weeks of flooding and threatened our coal deliveries. We focused on improving drainage infrastructure and using stockpiles to mitigate future risks.

Climate Change
We believe in open and transparent reporting on climate change. Our climate change reporting is structured as per guidance from the Financial Stability Board's Task Force on Climate-Related Financial Disclosures ("TCFD") recommendations. The following highlights our management, performance and leadership of climate change related impacts. For more detailed information, please visit our Climate Change Management webpage: https://www.transalta.com/sustainability/climate-change-management/

Governance
The highest level of oversight on climate change related business impacts is at our Board level, specifically by our Governance Safety and Sustainability Committee ("GSSC") of the Board and the Audit and Risk Committee ("ARC") of the Board. Business impacts related to climate change are assessed by our executive team quarterly and reported to the Board GSSC and ARC, as applicable.

Strategy
Our corporate vision is to be a leading clean power company by 2025. To support this vision our strategic goals include growth in renewable energy and gas, while reducing a significant amount of emissions from our coal fleet by way of coal-to-gas conversions and coal retirements.

Our corporate goal is to reduce our GHG emissions by 19.7 million tonnes by 2030 compared to 2015 levels, while we grow renewable energy and gas. Our modeling shows that our target aligns us, under many scenarios, with science-based target setting, which highlights the resilience of our business to 2 degrees of global warming. We have not officially validated a science-based target, but continue to monitor and model our future performance with the Sectoral Decarbonization Approach from the Science Based Target Initiative.

Aligned with our corporate strategy, our business units or operations consistently seek energy-efficiency improvements, development of emissions offset portfolios to achieve emissions reductions at competitive costs, and development of clean combustion technologies.

We seek investment in climate change related mitigation solutions, such as renewable energy development, where we can maximize value creation for our shareholders, local communities and the environment. Conversion of our large coal fleet to gas-fired generation highlights this approach, which will allow us to run our assets longer than the federally mandated coal retirement schedule. Our goals for undertaking such actions are to enhance value for our shareholders, ensure low-cost and reliable power for Albertans, and reduce the environmental impact from coal-fired generation.

Our investment and growth in renewable energy is highlighted by our diverse portfolio of renewable energy-generating assets. We currently operate over 2,200 MW of hydro, wind and solar power. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. Production from renewable energy in 2018 resulted in avoidance of approximately 2.9 million tonnes of CO_2e, which is equivalent to removing over 620,000 vehicles from North American roads over the same year. For further details on governance and risk, see the Governance and Risk Management section of this MD&A.

Risk Management

Risks and opportunities are identified at the business unit level and through corporate functions (government relations, regulatory, emissions trading and sustainability). Furthermore, risks and opportunities are monitored through our Corporation-wide risk management processes and actively managed on a priority basis. As noted above risks and opportunities are reviewed by our executive team quarterly and reported to the Board GSSC and ARC, as applicable.

The following highlights identified climate change risk or opportunities, which have been assessed and integrated into business operations.

Risk or opportunity	Management approach
Policy requirements	TransAlta supports smart regulation and carbon pricing that ensures economic growth and certainty for investment. We have also demonstrated co-operation and collaboration on climate-related policy, while ensuring we protect value for employees and shareholders. This is evidenced by our Off-Coal Agreement with the Alberta Government, totallng $524 million and MOU to convert coal plants to gas. Further climate-related policy updates can be found in the Regional Regulation and Compliance subsection of this MD&A
Carbon pricing	Our Corporate function attributes regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks pertaining to uncertainty in the carbon market and as a safeguard to anticipate future impacts of regulatory changes on facilities. This information is directed to the business unit level for further integration. Identified climate change risks or opportunities and carbon pricing are recognized in the annual TransAlta long-and-medium range forecasting processes. We capture economic profit from carbon markets through generation of renewable energy credits or offsets and via our emission trading function, which seeks to commoditize and profit from carbon trading.
New technology	We have demonstrated upside in growing renewables and gas-powered generation. From 2000 to 2018 we have grown renewables capacity from approximately 900 MW to over 2,200 MW. We have recently announced development of three wind projects, totaling over 330 MW of future capacity.
Adaptation and mitigation	Our clean power strategy means that all new investment must meet clean standards in order to mitigate potential future risk related to carbon policy and pricing. Our target is for 100 per cent of net generation capacity to be from gas and renewables capacity by 2025. Our coal-to-gas conversion plan in Alberta is an adaptive measure to climate change related policy. Using existing infrastructure significantly reduces capital costs compared with new gas builds and also results in the avoidance of approximately $15/MW in carbon-related pricing (assuming a $30 per tonne carbon price). Our new gas facility at South Hedland Power Station is built with adaptation in mind. The facility will operate with a best-in-class emission intensity, and the facility uses less water than traditional gas plants as we use dry cooling towers as opposed to the normal wet cooling towers (wet cooling towers have heavy water consumption). The plant is designed to withstand a category 5 cyclone, which can frequent the northwest region of Western Australia. Category 5 is the highest cyclone rating. Floods, which can occur in the area, have been mitigated by constructing the facility above the normal flood levels.
Water stress	Our thermal plants require water for operation. The majority of our thermal facilities are operated in low water stress environments. Our most water-stressed area of operation is at Sarnia; however, due to the nature of the operation, 98 per cent of water is recycled. The plant is a cogeneration facility. At all of our coal facilities we hold licences to pull water from low stressed areas. In Australia we purchase water for operations, and despite operating in remote locations, these areas are not currently water-stressed. Water purchasing will allow us to minimize local water stress if this becomes an issue. Our operating cost increase exposure due to water in Australia is low as our thermal operations are small.

Greenhouse Gas Emissions

In 2018, we estimate that 20.8 million tonnes of GHGs with an intensity of 0.77 tonnes per MWh (2017-29.9 million tonnes of GHGs with an intensity of 0.86 tonnes per MWh) were emitted as a result of normal operating activities. Our significant reduction in GHG emissions is the result of coal closures and reduced coal power generation from our Sundance facility in Alberta and increased co-firing with gas at our merchant coal facilities. Notably, our 2018 emissions reductions, supported achieving our 2021 target to reduce GHG emissions by 30 per cent over 2015 levels of 32.2 million tonnes CO_2e. This target was achieved well ahead of schedule and supports our clean power transition.

Our 2018 data are estimates based on best available data at the time of report production. GHGs include water vapour, 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. Emissions intensity data has been aligned with the "Setting Organizational Boundaries: Operational Control" methodology set out in *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* developed by the World Resources Institute and the World Business Council for Sustainable Development. As per the methodology, TransAlta reports emissions on an operation control basis, which means that we report 100 per cent of emissions at facilities in which we are the operator. Emissions intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership.

The following are our GHG emissions in million tonnes CO_2:

Year ended Dec. 31	2018	2017	2016
Coal	**18.3**	27.4	27.7
Gas and renewables	**2.4**	2.5	3.0
Total GHG emissions	**20.8**	**29.9**	**30.7**

Our total GHG emissions include both scope 1 and scope 2 emissions. The GHG Protocol Corporate Standard classifies a company's GHG emissions into three 'scopes'. Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy. Scope 3 emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. Scope 1 emissions in 2018 were estimated to be 20.6 million tonnes CO_2e. Scope 2 emissions were estimated to be 0.2 million tonnes CO_2e. We estimate our scope 3 emissions to be in the range of six million tonnes.

Future performance on GHG emissions will reduce as we retire or convert coal plants to gas and grow our renewable energy and gas fleet, while optimizing our existing fleet. Our target to is to reduce 60 per cent or 19.7 million tonnes of GHG emissions by 2030 over 2015 levels, which is line with UN Sustainable Development Goal ("SDG") Goal 13, Climate Action. Since 2015 we have reduced 9.1 million tonnes, which represents a reduction of 35 per cent.

The following highlights our longer-term track record on GHG emission reductions since 2005 and our projected emissions in 2030.

Year ended Dec. 31	2030	2018	2005
Total GHG emissions	**12.5**	20.8	41.9

In 2018, TransAlta maintained its scoring on the Carbon Disclosure Project Climate Change investor request. Our overall score was a B, which places us as ahead of our peers when it comes to carbon disclosure, management, performance and leadership. In 2017 we were highlighted by the Chartered Professional Accountants of Canada ("CPA Canada") as the only company in Canada, out of 75 companies, that reports on climate change across all levels of disclosure: the Annual Information Form, this MD&A and our information circular. Our 2016 Integrated Report was selected as a finalist for CPA Canada's Award of Excellence in Corporate Reporting - of note, our Climate Change disclosure was highlighted as "outstanding" by CPA Canada judges.

Regional Regulation and Compliance

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

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

Canadian Federal Government

On June 21, 2018, the *Greenhouse Gas Pollution Pricing Act* (GGPPA) was passed. Under this Act, the Canadian federal government implemented a national price on GHG emissions. The price will begin at $20 per tonne of CO_2e for emissions in 2019, rising by $10 per year, until reaching $50 per tonne in 2022.

On Jan. 1, 2019, the GGPPA's "backstop" mechanisms came into effect for large emitters in jurisdictions that did not have an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system - Ontario, Manitoba, New Brunswick, Saskatchewan, Prince Edward Island, Yukon and Nunavut. The backstop mechanism has two components: a carbon levy for small emitters and regulation for large emitters called the Output-Based Pricing System (OBPS). The carbon levy sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources.

The OBPS is an intensity-based standard where large emitters must meet an industry specific emission intensity performance standard per unit of production. A large emitter's emission intensity per unit of product must meet their industry's OBPS intensity performance standard. If the facility's emission intensity is below or above the performance standard, the facility will generate carbon credits or carbon obligations equal to the difference between the industry's emission intensity performance standard and the regulated facility's emission intensity.

Federal Gas Regulation

On Dec. 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. Under the regulation, new and significantly modified natural-gas-fired electricity facilities with a capacity greater than 150 MWs must meet a standard of 420 tCO_2e per gigawatt hour (tCO_2e/GWh) to operate. Units with a capacity of between 25 MW and 150 MW must meet a standard of 550 tCO_2e/GWh.

The rules for converted units will allow the plants to operate for a set number of years following the end-of-life for the unit under the coal regulations based on a one-time performance test at the time of conversion. For our units, these rules are expected to provide 8 or 10 additional years of operating life to each of our units.

Federal Coal Regulation

On Dec. 18, 2018, amendments to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* came into force under the *Canadian Environmental Protection Act*, 1999. The amended regulations will require coal units to meet an emission level of 420 tCO2e/GWh by the earlier of end-of-life under the 2012 regulations or Dec. 31, 2029.

Alberta

On November 22, 2015, the Government of Alberta announced the Alberta Climate Leadership Plan. The government has now largely delivered on its commitments through legislation to require:

- the elimination of coal generation by 2030;
- the creation of the Renewable Energy Program (REP) to meet the commitment that renewables account for 30 per cent of Alberta's electricity system by 2030. Under the REP, the system operator, the AESO, is tasked with running procurement processes for government approved volumes of renewable power. To date, the AESO has run three separate Requests for Proposals (RFP). The RFPs have resulted in 20-year contracts for approximately 1,360 MWs of wind power projects. These projects are scheduled to be grid integrated between 2019 and 2021;
- the *Carbon Competitiveness Incentive Regulation* (CCIR) replaces the previous large emitters regulation, *Specified Gas Emitters Regulation* (SGER), moving from a facility-specific compliance standard to a product or sector performance compliance standard; and
- a carbon levy was introduced on most carbon emissions not covered by the CCIR.

On Jan. 1, 2018, the Alberta government transitioned from the SGER to the CCIR. Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sector performance compliance standard. Currently, the provincial government has announced that the carbon price will remain at \$30/tCO_2e going forward and will not increase to the federally mandated price increase of \$40/tCO_2e in 2021 and \$50/tCO2e in 2022; however, increases may be implemented by the federal government under their program equivalency review. The electricity sector performance standard was set at 370 tCO_2e/GWh but will decline over time. All renewable assets that received crediting under the SGER will continue to receive credits under CCIR on a one-to-one basis. All other renewables that did not receive credits under the previous standards will now be able to opt in to the CCIR and get carbon crediting up to the electricity sector performance standard in perpetuity. Once wind projects' crediting under SGER protocol ends, these projects will also be able to opt in to the CCIR system and be credited up to the performance standard for the rest of their operational life.

British Columbia

Beginning April 1, 2018, BC increased its carbon tax rate to \$35/tCO_2e and committed to raise the price \$5 per year until it reaches \$50 per tonne in 2021.

BC Hydro has indicated there will be no additional contracts for independent power producer renewable projects with capacity above 15 MW. It has also suspended the purchase of energy from its Standing Offer Program for small projects up to 15 MW pending a review of the program.

Ontario

On Oct. 31, 2018, the Ontario government passed the *Cap and Trade Cancellation Act*. This Act removed all existing provincial carbon emission regulations and costs on large emitters.

The Canadian federal *Greenhouse Gas Pollution Pricing Act* requires provinces to have GHG gas regulations and prices in place that align with the federal GGPPA. On Oct. 23, the federal government announced that the federal program would be implemented in Ontario as of Jan. 1, 2019. Small emitters will face a carbon levy and large emitters, under covered industries, with annual GHG emission greater than 50,000 tCO_2e will be subject to the OBPS. Ontario is now subject to the federal government's backstop carbon levy price for small emitters and the OBPS for large emitters.

On Nov. 29th, 2018, the Ontario government unveiled a new climate change policy called Preserving and Protecting our Environment for Future Generations: A Made-In-Ontario Environment Plan. The plan aims to keep the province working toward meeting the emissions-reduction goal of achieving 30 per cent reduction of 2005 levels by 2030. The plan commits to developing emission performance standards to achieve reductions from large emitters and references Saskatchewan's OBPS as an example. The government has indicated that it will be consulting and developing the program in 2019. The plan's specifics related to the electricity sector have not yet been defined and are expected to be determined through the program development process.

Australia

On Dec. 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The AUD 2.55 billion ERF is the centrepiece of the Australian government's policy and provides a policy framework to cut emissions by five per cent below 2000 levels by 2020 and 26 to 28 per cent below 2005 emissions by 2030.

The ERF's safeguard mechanism, commencing from July 1, 2016, is designed to ensure emissions reductions purchased by the Australian government through the ERF are not displaced by significant increases in emissions elsewhere in the economy. The ERF and its safeguard mechanism provide incentives to reduce emissions across the Australian economy.

The Australian government has also committed to develop a National Energy Productivity Plan with a target to improve Australia's energy productivity by 40 per cent between 2015 and 2030. The ERF is not expected to have a material impact on our Australian assets as a result of the Australian assets being primarily composed of gas-fired generation.

In addition, on June 23, 2015, the federal Australian government also reformed the Renewable Energy Target ("RET") scheme. The RET should add at least 33,000 gigawatt-hours (GWh) of renewable sources by 2020. This would double the amount of large-scale renewable energy being delivered compared to current levels and result in approximately 23.5 per cent of Australia's electricity generation being sourced from renewable projects.

Pacific Northwest

In 2010, the Washington Governor's office and Ecology negotiated agreements with TransAlta related to the operation of Centralia's two coal power electricity generating units. TransAlta agreed to retire its two Centralia coal units - one in 2020 and the other in 2025. This agreement is formally part of the state's climate change program. We currently believe that there will be no additional GHG regulatory burden on US Coal given these commitments. The related *TransAlta Energy Transition Bill* was signed into law in 2011 and provides a framework to transition from coal to other forms of generation in the State of Washington.

2018 Sustainability Performance

Stakeholder Communication and Value Creation

The information in this section seeks to highlight our ability to create value for investors, stakeholders and society in the short, medium and long term. The selection of key information and key metrics disclosed in this integrated report and our full sustainability disclosures follow a materiality assessment process, which identifies key impact areas to our stakeholders. We subsequently are guided by, and place focus on, reporting on these key areas.

Sustainability Targets and Results

Sustainability targets are strategic goals that support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas.

2018 Sustainability Targets

	Financial	Results	Comments
1. Maintain our investment grade rating	Achieve and maintain investment grade credit metrics	Partly achieved	TransAlta maintains investment grade ratings from three out of four rating agencies: S&P (BBB-) negative outlook, DBRS (BBB low) stable outlook, and Fitch (BBB-) stable outlook.
2. Increase focus on FFO and EBITDA	Deliver comparable EBITDA and FFO in the range of $1,000 million to $1,050 million and $750 million to $800 million, respectively(1)	Achieved	For the year ended Dec. 31, 2018, adjusted comparable EBITDA was $988 million and adjusted FFO was $770 million. Comparable EBITDA was adjusted to remove the impact of unrealized mark-to-market gains or losses. Additionally, Comparable EBITDA and FFO were adjusted to remove the $157 million for the termination of Sundance B and C PPAs as this was not included in the targets.

(1) Represents our revised outlook. As a result of strong performance in the first quarter of 2018, we revised the following 2018 targets: comparable EBITDA from the previously announced target range of $950 million to $1,050 million to $1,000 to $1,050 million, and FFO from the target range of $725 million to $800 million to $750 million to $800 million.

	Human and Intellectual	Results	Comments
3. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.53	Mostly Achieved	Although we narrowly missed our target, we achieved one of our lowest IFRs in our history. Our 2018 IFR was 0.54, a 25 per cent improvement over 2017 performance
	Achieve a Total Incident Frequency rate below 2.83	Achieved	Our 2018 TIF was 1.98, a 25 per cent improvement over 2017 performance
4. Human resources	Maintain voluntary turnover percentage under eight per cent	Not achieved	Our voluntary turnover in 2018 was 20 per cent. We seek to maintain voluntary turnover or attrition under eight per cent as this is considered a healthy amount of attrition for a corporation. As we transition away from coal-fired generation and its associated jobs we face significant workforce challenges with retention
5. Support employee development	Continue development plans for all high-potential employees at the top three levels of the organization	Achieved	In 2018, we completed a six-month (peer-led) leadership training program, called Elevate, for our high-potential employees at the top three levels of the organization. The program was focused on establishing a learner's mindset, building trust and influence, strengths-based leadership, being transparent, providing feedback, collaboration as a team and innovation

	Natural	Results	Comments
6. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 9	Achieved	We recorded seven significant environmental incidents in 2018, none of which had a material environmental impact. This was below our target of nine, but was a 40 per cent increase over 2017 performance
7. Increase mine reclaimed acreage	Replace annual topsoil rate at Highvale mine at a rate of 74 acres/year	Not achieved	Due to weather conditions, not all topsoil was placed to fully meet our target. Top Soil is the last stage of reclamation, despite weather constraints, we did manage to complete 28 acres. Instead, we reallocated resources to other stages of reclamation to move other areas closer to final reclamation (such as ground leveling). Overall we reduced reclamation spend by $2.1 million and maintained progress towards our long-range reclamation plan
9. Reduce air emissions	Achieve a 95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030	On track	We are well underway and on track to achieve our target of 95 per cent emission reductions of SO_2 and NOx by 2030. Since 2005, we have reduced NOx emissions by 58 per cent and SO_2 emissions by 72 per cent. In 2018 we reduced approximately 16,000 tonnes of NOx emissions and 17,000 tonnes of SO_2 emissions over 2017 levels
10. Reduce GHG emissions	a) Our goal is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels, in line with a commitment to the UN SDGs	Achieved	We achieved this target in 2018, well ahead of our target for 2021. In 2018 we reduced approximately 9.1 million tonnes of CO_2e over 2017 levels due to reduced coal power generation from our Sundance facility and co-firing at our merchant coal facilities
	b) Our goal is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and to prevent two degrees Celsius of global warming	On track	We are well underway and on track to achieve our target of 60 per cent GHG emission reductions by 2030. Since 2015, we have reduced emissions by 36 per cent. In 2018 we reduced approximately 9.1 million tonnes of CO_2e over 2017 levels

	Social and Relationship	Results	Comments
11. Support quality education for youth	Support equal access to all levels of education for youth and Indigenous peoples	Achieved	TransAlta provides an Aboriginal bursary to support education for Indigenous peoples that includes bursaries for both trades and post-secondary. TransAlta's criteria for accessing the bursary are open to any educational pursuit that will support the well being of Indigenous peoples and communities. The bursary is open to all Indigenous applicants that have completed high school. TransAlta has also created a Indigenous Gap program with SAIT to give support to Indigenous students where it is needed.
Our education goal and targets support UN SDG Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"	Direct approximately $0.75 million of community investment spending to youth education	Achieved	Our community investments have supported the University of Calgary, Southern and Northern Alberta Institute of Technology, Mount Royal University, Banff Centre for Arts and Creativity (Indigenous leadership scholarships), Mother Earth Children's Charter School (Indigenous kindergarten to Grade 9), Calgary Stampede (The Young Canadians - ages 7 to 18), national Canada and US Indigenous scholarships (post-secondary for trades and academic) and the Alberta Council for Environmental Education
12. Increase internal best practice Aboriginal engagement awareness	Develop sustainability and Indigenous engagement materials for integration within our developmental leadership programs at TransAlta	Achieved	An Indigenous Awareness presentation was developed, that includes historical facts and basic concepts around consultation and engagement, which will be shared with all employees. The same presentation will be used at the Schulich School of Engineering at the University of Calgary in 2018 for one of their ethics courses

	Comprehensive	Results	Comments
13. TransAlta will be a leading clean power company by 2030	By 2022, we will convert six coal plant units from coal-fired generation to gas-fired generation	On track	In 2018 we exercised our option to acquire a 50 per cent ownership in the Pioneer Pipeline connecting Tidewater's Brazeau River Complex to TransAlta's generating units at Sundance and Keephills. Our investment is subject to regulatory approval
Our clean power goal and targets support the UN SDG Goal 7: Affordable and Clean Energy related to ensuring "access to affordable, reliable, sustainable and modern energy"	By 2025, 100 per cent of our owned asset company-wide net generation capacity will be from gas and renewables	On track	We continued our coal-to-gas transition plans in 2018, while announcing new renewable energy growth projects. Please see above and below for more detail.
	We will continue to seek new opportunities to grow our portfolio of 2,265 MW wind, hydro and solar assets	Achieved	In 2018 we announced development of three wind development projects, totaling over 320 MW of additional renewable energy capacity. Projects include a 90 MW wind facility in Pennsylvania (US), a 29 MW wind facility in New Hampshire (US) and a 207 MW wind facility in Alberta (Canada)
	Continue to explore viability of the Brazeau 900 MW pumped hydro expansion – doubling our hydro capacity in Alberta	Not achieved	In May 2018, the AESO released a report stating that dispatchable renewable resources are not needed in the Alberta market before 2030. The value and benefit of the Brazeau Hydro Pumped Storage project would be well beyond the 2030 period. The Corporation still believes that generation from pumped storage should be part of future calls for power under the Alberta *Renewable Electricity Program*. The Corporation is not spending additional development dollars on the project at this time, but will continue to work with governments to find the appropriate financial mechanisms for bringing low-cost, green, dispatchable renewables into the market to support low prices and emissions for Alberta customers

2019 Sustainable Development Targets

Our 2019 and longer-term sustainability targets support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas. We continue to evolve and adapt targets to focus on anticipated key areas of materiality to stakeholders. Targets are outlined below:

	Human and Intellectual	**Annual Performance Status**
1. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.43	20 per cent improvement over 2018 performance (0.54)
	Achieve a Total Incident Frequency Rate below 1.58	20 per cent improvement over 2018 performance (1.98)

		Annual Performance Status
2. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below five	44 per cent improvement over 2018 target
3. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 110 acres/year	57 per cent increase over 2018 target (70 acres)
4. Reduce air emissions	Achieve a 95 per cent reduction from 2005 levels of TransAlta SO_2 emissions and 50 per cent reduction in NOx emissions by 2030	Revised NOx target to align with coal-to-gas conversion strategy and growth in gas estimations
5. Reduce GHG emissions Our GHG goal and targets support UN SDG Goal 13: Climate Action related to ensuring "integrate climate change measures into national policies, strategies and planning."	Our goal is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming (our GHG and clean power targets assume reasonably anticipated growth and operating scenarios)	Consistent with 2018

	Social and Relationship	**Annual Performance Status**
6. Support quality education for youth	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	Consistent with 2018 target
Our education goal and target support UN SDG Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"		

	Comprehensive	**Annual Performance Status**
7. TransAlta will be a leading clean power company by 2025	Convert at least two coal units at Sundance, Alberta and three coal units at Keephills, Alberta to gas-fired generation in the 2020 to 2023 time frame	Revised 2018 target
Our clean power goal and targets support the UN SDG Goal 7: Affordable and Clean Energy related to ensuring "access to affordable, reliable, sustainable and modern energy"	Aim that by 2025, 100 per cent of our owned net generation capacity will be from clean power (renewables and gas)	Consistent with 2018 target
	Seek new opportunities to grow our renewable portfolio of 2,265 MW wind, hydro and solar assets	Consistent with 2018 target

Governance and Risk Management

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

Governance

The key elements of our governance practices are:

- employees, management and the Board are committed to ethical business conduct, integrity, and honesty;
- we have established key policies and standards to provide a framework for how we conduct our business;
- the Chair of our Board and all directors, other than our President and Chief Executive Officer ("CEO") are independent;
- the Board is comprised of individuals with a mix of skills, knowledge and experience that are critical for our business and our strategy;
- the effectiveness of the Board is achieved through robust annual evaluations and continuing education of our directors; and
- our management and Board facilitate and foster an open dialogue with shareholders and community stakeholders.

Commitment to ethical conduct is the foundation of our corporate governance model. We have adopted the following codes of conduct to guide our business decisions and everyday business activities:

- Corporate Code of Conduct, which applies to all employees and officers of TransAlta and its subsidiaries,
- Directors' Code of Conduct,
- Supplier's Code of Conduct,
- Finance Code of Ethics, which applies to all financial employees of the Corporation, and
- Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our codes of conduct outline the standards and expectations we have for our employees, officers, directors, consultants and suppliers with respect to, among other things, the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, avoiding conflicts of interest, respect in the workplace, social responsibility, privacy, compliance with laws, insider trading, environment, health and safety, and our commitment to ethical and honest conduct. Our Corporate Code of Conduct and Directors' Code of Conduct each goes beyond the laws, rules, and regulations that govern our business in the jurisdictions in which we operate; it outlines the principal business practices with which all employees and directors must comply.

Our employees, officers and directors are reminded annually about the importance of ethics and professionalism in their daily work, and must certify annually that they have reviewed and understand their responsibilities as set forth in the respective codes of conduct. This certification also requires our employees, officers and directors to acknowledge that they have complied with the standards set out in the respective code during the last calendar year.

The Board provides stewardship of the Corporation and ensures that the Corporation establishes key policies and procedures for the identification, assessment and management of principal risks and strategic plans. The Board monitors and assesses the performance and progress of the Corporation's goals through candid and timely reports from the CEO and the senior management team. We have also established an annual evaluation process whereby our directors are provided with an opportunity to evaluate the Board, Board committees, individual directors and the Chair's performance.

In order to allow the Board to establish and manage the financial, environmental, and social elements of our governance practices, the Board has established the Audit and Risk Committee ("ARC"), the Governance, Safety and Sustainability Committee ("GSSC"), and the Human Resources Committee (the "HRC").

The ARC, consisting of independent members of the Board, provides assistance to the Board in fulfilling its oversight responsibility relating to the integrity of our consolidated 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. The ARC approves our Commodity and Financial Exposure Management policies and reviews quarterly Enterprise Risk Management reporting.

The GSSC is responsible for developing and recommending to the Board a set of corporate governance principles applicable to the Corporation and for monitoring the compliance with these principles. The GSSC is also responsible for Board recruitment, succession planning and for the nomination of directors to the Board and its committees. In addition, the GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations and public policy changes and the establishment and adherence to environmental, health and safety practices, procedures and policies. The GSSC also receives an annual report on the annual codes of conduct certification process.

In regards to overseeing and seeking to ensure that the Corporation consistently achieves strong environment, health and safety ("EH&S") performance, the GSSC undertakes a number of actions that include: i) receiving regular reports from management regarding environmental compliance, trends, and TransAlta's responses; ii) receiving reports and briefings on management's initiatives with respect to changes in climate change legislation, policy developments as well as other draft initiatives and the potential impact such initiatives may have on our operations; iii) assessing the impact of the GHG policies implementation and other legislative initiatives on the Corporation's business; iv) reviewing with management the EH&S policies of the Corporation; v) reviewing with management the health and safety practices implemented within the Corporation, as well as the evaluation and training processes put in place to address problem areas; vi) receiving reports from management on the near-miss reporting program and discussing with management ways to improve the EH&S processes and practices; and vi) reviewing the effectiveness of our response to EH&S issues and any new initiatives put in place to further improve the Corporation's EH&S culture.

The HRC is empowered by the Board to review and approve key compensation and human resources policies of the Corporation that are intended to attract, recruit, retain and motivate employees of the Corporation. The HRC also makes recommendations to the Board regarding the compensation of the Corporation's CEO, including the review and adoption of equity-based incentive compensation plans, the adoption of human resources policies that support human rights and ethical conduct, and the review and approval of executive management succession and development plans.

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

The CEO and senior management review and report on key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity and Compliance Risk Committee, and weekly by the Managing Director Commodity Risk, the commercial managing directors in Trading and Marketing, and the Senior Vice-President Trading and Marketing.

The Investment Committee is chaired by our Chief Financial Officer and is comprised of the CEO, Chief Financial Officer, Chief Legal and Compliance Officer and Corporate Secretary, and Chief Investment Officer. 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, if required.

The Commodity Risk & Compliance Committee is chaired by our Senior Vice-President of Business Development and is comprised of the Chief Financial Officer, Chief Legal and Compliance Officer, Senior Vice-President of Business Development and Managing Director & Corporate Controller. It oversees the risk and compliance program in trading and ensures that this program is adequately resourced to monitor trading operations from a risk and compliance perspective. It also ensures the existence of appropriate controls, processes, systems and procedures to monitor adherence to policy.

TransAlta is listed on the TSX and the New York Stock Exchange and is subject to the governance regulations, rules and standards applicable under both exchanges. Our corporate governance practices meet the following governance rules of the TSX and Canadian Securities Administrators: i) Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings; ii) National Instrument 52-110 Audit Committees; iii) National Policy 58-201 Corporate Governance Guidelines; and iv) National Instrument 58-101 Disclosure of Corporate Governance Practices. As a "foreign private issuer" under US securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our management information circular.

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 code of conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision-makers including the Board, the ARC, senior management, and/or the Commodity Risk & Compliance Committee, as applicable. Reporting to this latter committee includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion and review of the status of actions to minimize risks. This quarterly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a process in place where employees, contractors, shareholders or other stakeholders may confidentially or anonymously report any potential legal or ethical concerns, including concerns relating to accounting, internal control accounting, auditing or financial matters or relating to alleged violations of our codes of conduct. These concerns can be submitted confidentially and anonymously, either directly to the ARC or through TransAlta's toll-free telephone or online Ethics Helpline. The ARC Chair is immediately notified of any material complaints and, otherwise, the ARC receives a report at every quarterly committee meeting on all findings related to any material complaints or complaints relating to accounting or financial reporting or alleged breaches in internal controls over financial reporting.

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, 2018, associated with our proprietary commodity risk management activities was $2 million (2017 - $5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other. For a further discussion of risk factors affecting the Corporation, readers are encouraged to read the Risk Factors section of our Annual Information Form for the year ended Dec. 31, 2018, available on our website at www.transalta.com and under our profile on SEDAR at www.sedar.com and on EDGAR at www.edgar.gov.

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 2018. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk
Volume risk relates to the variances from our expected production. For example, the financial performance of our Hydro, Wind and Solar operations is 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 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 facilities in locations 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 to mitigate regional or fuel-specific events.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	9

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.

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 preventive 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 proven technology in our generating facilities;
- 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 replacing 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 2018, we had approximately 85 per cent (2017 - 92 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 fulfil our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the cost 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 2018, 67 per cent (2017 - 57 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 85 per cent (2017 - 83 per cent) of our purchased coal costs were contractually fixed.

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.

Coal Supply Risk

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 operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At US Coal, interruptions at our supplier's mine, the availability of trains to deliver coal and the financial viability of our coal suppliers could affect our ability to generate electricity.

We manage coal supply risk by:

- ensuring that the majority of the coal used in electrical generation in Alberta is from reserves permitted through coal rights we have purchased or for which we have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties;
- using longer-term mining plans to ensure the optimal supply of coal from our mines;
- sourcing the majority of the coal used at US 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 US Coal;
- ensuring coal inventories on hand at Canadian Coal and US 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, and carefully matching the specifications mined with the requirements of our plants;
- co-firing natural gas with coal;
- monitoring the financial viability of US coal suppliers; and
- hedging diesel exposure in mining and transportation costs.

Environmental Compliance Risk

Environmental compliance 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 (including as set forth in the Alberta Climate Leadership Plan) and the US. We anticipate continued and growing scrutiny by investors and other stakeholders relating to sustainability performance. These changes to regulations may affect our earnings by reducing the operating life of generating facilities, imposing additional costs on the generation of electricity, such as emission caps or tax, 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 compliance 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 US to advocate that regulatory changes are well designed and cost effective;
- developing compliance plans that address how to meet or surpass 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, solar and hydro 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 GSSC.

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 fulfil 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 or third-party credit insurance if a counterparty goes over its limits. Such security instruments can be collected if a counterparty fails to fulfil its obligation; 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 by 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, 2017. We had no material counterparty losses in 2018. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2018:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1)	86	14	**100**	**731**
Long-term finance lease receivables	100	—	**100**	**191**
Risk management assets(1)	99	1	**100**	**808**
Loan receivable(2)	—	100	**100**	**77**
Total				**1,807**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparties have no external credit ratings.

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $13 million (2017 - $40 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 US-denominated debt. Our exposures are primarily to the US 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 US operations using US-denominated debt;
- entering into forward foreign exchange contracts to hedge future foreign-denominated expenditures including our US-denominated debt that is outside the net investment portfolio; and
- hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year and 30 per cent in the fourth year. The US exposure will be managed with a combination of interest expense on our US-denominated debt and forward foreign exchange contracts; the Australian exposure will be managed with forward foreign exchange contracts.

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 US 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	$27 million before tax

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to engage in trading and hedging activities, capital projects, debt refinancing and payment of liabilities, capital structure 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. Changes in credit ratings may also affect our ability and/or the cost of establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment. 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 challenge our ability to enter into these contracts or any ordinary course contract, decrease the credit limits granted, and increase the amount of collateral that may have to be provided. Certain existing contracts contain credit rating contingent clauses, that, when triggered, automatically increase costs under the contract or require additional collateral to be posted. Where the contingency is based on the lowest single rating, a one-level downgrade from a credit rating agency with an originally higher rating may not, however, trigger additional direct adverse impact.

We are focused on strengthening our financial position and flexibility and achieving stable investment grade credit ratings with rating agencies. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlooks, are set out in the Financial Capital section of this MD&A. Credit ratings are subject to revision or withdrawal at any time by the rating organization, and there can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, resulting in the adverse possible impacts identified above.

As at Dec. 31, 2018, we have liquidity of $1.0 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2019.

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 Commodity Risk & Compliance Committee, senior management and the ARC;
- maintaining investment grade credit ratings; and
- maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

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

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

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

At Dec. 31, 2018, approximately 14 per cent (2017 - six 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
Interest rate	15%	$1 million before tax

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 reviewed 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 Director approvals;
- using consistent and disciplined project management methodologies 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 before starting construction;
- 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 before proceeding with the project; and
- entering into labour agreements to provide security around cost and productivity.

Human Resource Risk

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

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

We manage this risk by:

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

In 2018, 50 per cent (2017 - 52 per cent) of our labour force was covered by 10 (2017 - 11) collective bargaining agreements. In 2018, four (2017 - four) agreements were renegotiated. We anticipate the successful negotiation of five collective agreements in 2019.

Regulatory and Political Risk

Regulatory and political risk is 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 regulation and 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. This risk includes, among other things, uncertainties associated with the development of capacity markets for electricity in the provinces of Alberta and Ontario, uncertainties associated with the development of carbon pricing policies, the qualification of our renewable facilities in Alberta to the generation of tradable GHG allowances as part of the transition from the *Specified Gas Emitters Regulation* to the new regulation to be formulated to give effect to the Alberta Climate Leadership Plan in 2020, as well as the influence of regulation on the value of allowances or credits generated.

We manage these risks systematically through our Legal and Regulatory groups and our Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electricity 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 industry and government agency led 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 and regulatory agencies 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 to our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in markets in which we operate 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 and transparent basis;
- applying innovative technologies to improve our operations, work environment and environmental footprint;
- 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, including the annual code of conduct sign-off.

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.

Cybersecurity Risk

We rely on our information technology to process, transmit and store electronic information and data used for the safe operation of our assets. In today's ever evolving cybersecurity landscape, any attacks or other breaches of network or information systems may cause disruptions to our business operations. Cyberattackers may use a range of techniques, from exploiting vulnerabilities within our user-base, to using sophisticated malicious code on a single or distributed basis to try to breach our network security controls. Attackers may also use a combination of techniques in their attempt to evade safeguards such as firewalls, intrusion prevention systems and antivirus software that exist on our network infrastructure systems. A successful cyberattack may allow for the unauthorized interception, destruction, use or dissemination of our information and may cause disruptions to our business operations.

We continuously take measures to secure our infrastructure against potential cyberattacks that may damage our infrastructure, systems and data. Our cybersecurity program aligns with industry best practices to ensure that a holistic approach to security is maintained. We have implemented security controls to help secure our data and business operations, including access control measures, intrusion detection and prevention systems, logging and monitoring of network activities, and implementing policies and procedures to ensure the secure operations of the business. We have also established security awareness programs to help educate our users on cybersecurity risks and their responsibilities in helping protect the business.

While we have systems, policies, hardware, practices, data backups, and procedures designed to prevent or limit the effect of the security breaches of our generation facilities and infrastructure and data, there can be no assurance that these measures will be sufficient or that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

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 Corporation is subject to changing laws, treaties and regulations in and between countries. Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on the Corporation.

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	$1 million

Legal Contingencies

We are occasionally named as a party in various disputes, claims and legal or regulatory 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 dispute, claim or proceeding will be resolved in our favour or our liabilities with respect to such claims will not have a material adverse effect on us or our business, operations or financial results.

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 Dec. 31, 2018. 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. All insurance policies are subject to standard exclusions. Cyber coverage is not currently purchased.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2018	2017
Revenues	**622**	638
Net earnings (loss) attributable to common shareholders	**(122)**	(145)
Cash flow from operating activities	**132**	81
Comparable EBITDA(1)	**233**	275
FFO(1)	**217**	219
FCF(1)	**98**	101
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.43)**	(0.50)
FFO per share(1)	**0.76**	0.76
FCF per share(1)	**0.34**	0.35
Dividends declared per common share(2)	**0.08**	0.04
Dividends declared per preferred share(2)	**0.52**	0.26

(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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(2) Dividends declared vary year over year due to timing of dividend declarations.

Financial Highlights

We delivered consistent results in the fourth quarter with FCF of $98 million, compared to $101 million last year. FFO was $217 million, which was comparable to the fourth quarter of 2017, as the business continues to deliver solid performance.

Net loss attributable to common shareholders in the fourth quarter of 2018 was $122 million ($0.43 net loss per share) compared to a net loss of $145 million ($0.50 net earnings per share) in the same period of 2017, an improvement of $23 million compared to last year. This was driven by an income tax recovery of $16 million compared to income tax expense of $105 million in 2017, which was high due to the US tax rate reduction. This improvement was partially offset by lower comparable EBITDA of $42 million and the write-off of project development costs of $23 million in the fourth quarter of 2018.

Segmented Cash Flows Generated by the Business and Operational Performance

Segmented cash flows generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs and provisions. It also excludes non-cash mark-to-market gains or losses. This is the cash flows available to pay our interest and cash taxes, distributions to our non-controlling partners and dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

Segmented cash flows and operational performance for the business during the quarter is as follows:

Three months ended Dec. 31	2018	2017
Availability (%)(1)	**91.5**	88.4
Production (GWh)(1)	**8,276**	10,374
Segmented cash inflow (outflow)(2)		
Canadian Coal	**16**	11
US Coal	**21**	15
Canadian Gas	**59**	56
Australian Gas(3)	**35**	33
Wind and Solar	**74**	73
Hydro	**11**	10
Generation cash inflow	**216**	198
Energy Marketing	**10**	15
Corporate	**(34)**	(28)
Total comparable cash inflow	**192**	185

(1) Availability and production includes all generating assets under generation operations that we operate and finance leases and excludes hydro assets and equity investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.
(2) This is not defined under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(3) 2017 cash flow revised to reflect the impacts of the change in the long-term receivable in Australian Gas.

Adjusted availability for the three months ended Dec. 31, 2018, improved compared with the same period in 2017. Lower production for the three months ended Dec. 31, 2018, compared to the same period in 2017 is primarily due to the termination of the Sundance B and C PPAs and derates, partially offset by higher dispatch optimization in US Coal and higher Ancillary Services within our Hydro segment.

Cash flows generated by the business totalled $192 million in the fourth quarter, an increase of $7 million compared with last year's performance. Increased cash flows are largely due to the strong merchant prices in the Alberta market, lower sustaining capital spend and the settlement of a long-term receivable in Australian Gas, partially offset by higher carbon compliance costs.

Discussion of Consolidated Financial Results

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, including the comparable figures below 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 segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Comparable EBITDA

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

Three months ended Dec. 31	**2018**	2017
Net earnings (loss) attributable to common shareholders	**(122)**	(145)
Net earnings attributable to non-controlling interests	**43**	19
Preferred share dividends	**20**	10
Net earnings (loss)	**(59)**	(116)
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**(16)**	105
Gain on sale of assets and other	**—**	(1)
Foreign exchange (gain) loss	**—**	(6)
Net interest expense	**50**	57
Depreciation and amortization	**152**	180
Comparable reclassifications		
Decrease in finance lease receivables	**15**	15
Mine depreciation included in fuel cost	**37**	20
Australian interest income	**1**	1
Adjustments to earnings to arrive at comparable EBITDA		
Impacts associated with Mississauga recontracting(1)	**30**	20
Asset impairment charge (reversal)	**23**	—
Comparable EBITDA	**233**	275

(1) Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2018, are as follows: revenue $30 million (2017 - $29 million) and recovery related to renegotiated land lease of nil (2017 - $9 million).
(2) Asset impairment charges for the three months ended Dec. 31, 2018, include a write-off of project development costs of $23 million.

A summary of our comparable EBITDA by segments for the three months ended Dec. 31, 2018 and 2017 is as follows:

Three months ended Dec. 31	**2018**	2017
Comparable EBITDA		
Canadian Coal	**56**	66
US Coal	**(1)**	21
Canadian Gas	**73**	62
Australian Gas	**32**	29
Wind and Solar	**72**	78
Hydro	**17**	14
Energy Marketing	**12**	25
Corporate	**(28)**	(20)
Total comparable EBITDA	**233**	275

Comparable EBITDA decreased by $42 million for the fourth quarter 2018, compared to 2017, primarily as a result of:

- Our Canadian Coal results were down $10 million mainly due to higher carbon compliance costs in 2018.
- US Coal results were down $22 million primarily due to unfavourable changes on unrealized mark-to-market positions.
- Our Canadian Gas business was up $11 million period-over-period due to higher market price impacts.
- Australian Gas was up $3 million and was fairly consistent with prior year results.
- Wind and Solar results were down $6 million period-over-period mainly due to lower production, partially offset by higher prices in Alberta.
- Hydro results were $3 million higher period-over-period due to higher Ancillary Service revenues.
- Energy Marketing's comparable EBITDA was down $13 million during the fourth quarter of 2018 compared to 2017 mainly because the 2017 results were very strong in the Alberta market.
- Corporate costs increased by $8 million in the fourth quarter mainly due to higher contractor costs.

Funds from Operations and Free Cash Flow

FFO per share and FCF per share are calculated as follows using the weighted average number of common shares outstanding during the period. FFO, FFO per share, FCF and FCF per share are non-IFRS measures, are not defined under IFRS, and therefore, should not be considered in isolation or as an alternative to or to be more meaningful than cash flow from operating activities as determined in accordance with IFRS, when assessing our financial performance or liquidity. See the Additional IFRS Measures and Non-IFRS Measures section above and elsewhere in this MD&A for further details. The table below reconciles our cash flow from operating activities to our FFO and FCF:

Three months ended Dec. 31	**2018**	2017
Cash flow from operating activities	**132**	81
Change in non-cash operating working capital balances	**69**	121
Cash flow from operations before changes in working capital	**201**	202
Adjustments		
Decrease in finance lease receivable	**15**	15
Other	**1**	2
FFO	**217**	219
Deduct:		
Sustaining capital	**(56)**	(62)
Productivity capital	**(9)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(43)**	(36)
Other	**(1)**	(1)
FCF	**98**	101
Weighted average number of common shares outstanding in the period	**286**	288
FFO per share	**0.76**	0.76
FCF per share	**0.34**	0.35

FFO was down $2 million during the fourth quarter of 2018 compared to the same period in 2017. FCF decreased by $3 million period-over-period as we continued to reduce our sustaining capital spend as a result of our decision to mothball certain Sundance units.

The table below provides a reconciliation of our comparable EBITDA to our FFO and FCF:

Three months ended Dec. 31	**2018**	2017
Comparable EBITDA	**233**	275
Provisions	**—**	(10)
Unrealized (gains) losses from risk management activities	**27**	(8)
Interest expense	**(40)**	(52)
Current income tax expense	**(10)**	(6)
Realized foreign exchange gain (loss)	**1**	8
Decommissioning and restoration costs settled	**(8)**	(7)
Other non-cash items	**14**	19
FFO	**217**	219
Deduct:		
Sustaining capital	**(56)**	(62)
Productivity capital	**(9)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(43)**	(36)
Other	(1)	(1)
Comparable FCF	**98**	101
Weighted average number of common shares outstanding in the period	**286**	288
Comparable FFO per share	**0.76**	0.76
Comparable FCF per share	**0.34**	0.35

Selected Quarterly Information

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, which impacts production at US 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.

	Q1 2018	Q2 2018	Q3 2018	**Q4 2018**
Revenues	588	446	593	**622**
Comparable EBITDA	416	225	249	**233**
FFO	318	188	204	**217**
Net earnings (loss) attributable to common shareholders	65	(105)	(86)	**(122)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.23	(0.36)	(0.30)	**(0.43)**
	Q1 2017	**Q2 2017**	**Q3 2017**	**Q4 2017**
Revenues	578	503	588	638
Comparable EBITDA	274	268	245	275
FFO	202	187	196	219
Net earnings (loss) attributable to common shareholders	—	(18)	(27)	(145)
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	—	(0.06)	(0.09)	(0.50)

(1) 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.

Reported net earnings, comparable EBITDA, and FFO are generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate and lower planned outages.

Net earnings attributable to common shareholders has also been impacted by the following variations and events:

- effects of impairment charges during the second, third and fourth quarters of 2018 and second quarter of 2017;
- recognition of the $157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018;
- a recovery of a writedown of deferred tax assets in the second quarter of 2017;
- change in income tax rates in the US in the fourth quarter of 2017;
- effects of non-comparable unrealized gains on intercompany financial instruments that are attributable only to the non-controlling interests in the first quarter of 2017;
- effects of changes in useful lives of certain Canadian Coal assets during the first, second and third quarters of 2017; and
- effects of an impairment of $137 million in 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). There have been no changes in our ICFR or DC&P during the year ended Dec. 31, 2018, that have materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS. Management has used the *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) in order to assess the effectiveness of the Corporation's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation are recorded, processed, summarized and reported within the time frame specified in securities legislation. DC&P 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 securities legislation 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.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, 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 as such may not prevent or detect all misstatements, and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2018, the end of the period covered by this report, our ICFR and DC&P were effective.

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

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

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

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

Dawn L. Farrell
President and Chief Executive Officer

Christophe Dehout
Chief Financial Officer

February 26, 2019

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's ("TransAlta") internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States *Securities Exchange Act of 1934* and *National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings).*

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

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is a suitable framework for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

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

TransAlta proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2018 Consolidated Financial Statements of TransAlta included $588 million and $521 million of total and net assets, respectively, as of December 31, 2018, and $244 million and $27 million of revenues and net loss, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at December 31, 2018, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended December 31, 2018, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell	**Christophe Dehout**
President and Chief Executive Officer	Chief Financial Officer

February 26, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on Internal Control over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Consolidated Statements of Financial Position of TransAlta Corporation as of December 31, 2018 and 2017, and the related Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Changes in Equity and Cash Flows for each of the three years in the period ended December 31, 2018 and the related notes and our report dated February 26, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

TransAlta Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on TransAlta Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to TransAlta Corporation in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2018 consolidated financial statements of TransAlta and constituted $588 million and $521 million of total and net assets, respectively, as of December 31, 2018, and $244 million and $27 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

Ernst + Young LLP

Chartered Professional Accountants
Calgary, Canada
February 26, 2019

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying Consolidated Statements of Financial Position of TransAlta Corporation as of December 31, 2018 and 2017, the related Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Changes in Equity and Cash Flows, for each of the years then ended, and the related notes (collectively referred to as the "Consolidated Financial Statements"). In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of TransAlta Corporation at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 26, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of TransAlta Corporation's management. Our responsibility is to express an opinion on TransAlta Corporation's Consolidated Financial Statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to TransAlta Corporation in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements. We believe that our audits provide a reasonable basis for our opinion.

Ernst & Young LLP

Chartered Professional Accountants
We have served as TransAlta Corporation and its predecessor entities' auditor since 1947
Calgary, Canada
February 26, 2019

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2018**	2017	2016
Revenues (Note 5)	**2,249**	2,307	2,397
Fuel and purchased power (Note 6)	**1,100**	1,016	963
Gross margin	**1,149**	1,291	1,434
Operations, maintenance and administration (Note 6)	**515**	517	489
Depreciation and amortization	**574**	635	601
Asset impairment charges (reversals) (Note 7)	**73**	20	28
Taxes, other than income taxes	**31**	30	31
Net other operating expense (income) (Note 9)	**(204)**	(49)	(193)
Operating income	**160**	138	478
Finance lease income	**8**	54	66
Net interest expense (Note 10)	**(250)**	(247)	(229)
Foreign exchange gain (loss)	**(15)**	(1)	(5)
Gain on sale of assets and other	**1**	2	4
Earnings (loss) before income taxes	**(96)**	(54)	314
Income tax expense (recovery) (Note 11)	**(6)**	64	38
Net earnings (loss)	**(90)**	(118)	276
Net earnings (loss) attributable to:			
TransAlta shareholders	**(198)**	(160)	169
Non-controlling interests (Note 12)	**108**	42	107
	(90)	(118)	276
Net earnings (loss) attributable to TransAlta shareholders	**(198)**	(160)	169
Preferred share dividends (Note 25)	**50**	30	52
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Weighted average number of common shares outstanding in the year *(millions)*	**287**	288	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 24)	**(0.86)**	(0.66)	0.41

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2018**	2017	2016
Net earnings (loss)	**(90)**	(118)	276
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**15**	(6)	8
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(2)]	**—**	(1)	(1)
Total items that will not be reclassified subsequently to net earnings	**15**	(7)	7
Gains (losses) on translating net assets of foreign operations, net of tax[(3)]	**84**	(80)	(71)
Reclassification of translation gains on net assets of divested foreign operations[(4)] (Note 4)	**—**	(9)	—
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(5)]	**(41)**	50	18
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[(6)] (Note 4)	**—**	14	—
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(7)]	**(8)**	214	179
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(8)]	**(46)**	(107)	(48)
Total items that will be reclassified subsequently to net earnings	**(11)**	82	78
Other comprehensive income	**4**	75	85
Total comprehensive income (loss)	**(86)**	(43)	361

Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(210)**	(74)	215
Non-controlling interests (Note 12)	**124**	31	146
	(86)	(43)	361

(1) Net of income tax expense of 5 million for the year ended Dec. 31, 2018 (2017 - 4 million recovery, 2016 - 4 million expense).
(2) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - nil , 2016 - nil).
(3) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - nil, 2016 - 11 million expense).
(4) Net of reclassification of income tax of nil for the year ended Dec. 31, 2018 (2017 - 11 million expense, 2016 - nil).
(5) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 2 million expense, 2016 - 5 million expense).
(6) Net of reclassification of income tax of nil for the year ended Dec. 31, 2018 (2017 - 2 million recovery, 2016 - nil).
(7) Net of income tax recovery of 1 million for the year ended Dec. 31, 2018 (2017 - 77 million recovery, 2016 - 92 million expense).
(8) Net of reclassification of income tax expense of 11 million for the year ended Dec. 31, 2018 (2017 - 31 million expense, 2016 - 41 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2018**	2017
Cash and cash equivalents	**89**	314
Restricted cash (Note 22)	**66**	—
Trade and other receivables (Note 13)	**756**	933
Prepaid expenses	**13**	24
Risk management assets (Note 14 and 15)	**146**	219
Inventory (Note 16)	**242**	219
	1,312	1,709
Restricted cash (Note 22)	**—**	30
Long-term portion of finance lease receivables (Note 8)	**191**	215
Property, plant and equipment (Note 17)		
Cost	**13,202**	12,973
Accumulated depreciation	**(7,038)**	(6,395)
	6,164	6,578
Goodwill (Note 18)	**464**	463
Intangible assets (Note 19)	**373**	364
Deferred income tax assets (Note 11)	**28**	24
Risk management assets (Note 14 and 15)	**662**	684
Other assets (Note 20)	**234**	237
Total assets	**9,428**	10,304
Accounts payable and accrued liabilities	**497**	595
Current portion of decommissioning and other provisions (Note 21)	**70**	67
Risk management liabilities (Note 14 and 15)	**90**	101
Income taxes payable	**10**	64
Dividends payable (Note 24 and 25)	**58**	34
Current portion of long-term debt and finance lease obligations (Note 22)	**148**	747
	873	1,608
Credit facilities, long-term debt and finance lease obligations (Note 22)	**3,119**	2,960
Decommissioning and other provisions (Note 21)	**386**	403
Deferred income tax liabilities (Note 11)	**501**	549
Risk management liabilities (Note 14 and 15)	**41**	40
Contract liabilities (Note 5)	**87**	62
Defined benefit obligation and other long-term liabilities (Note 23)	**287**	297
Equity		
Common shares (Note 24)	**3,059**	3,094
Preferred shares (Note 25)	**942**	942
Contributed surplus	**11**	10
Deficit	**(1,496)**	(1,209)
Accumulated other comprehensive income (Note 26)	**481**	489
Equity attributable to shareholders	**2,997**	3,326
Non-controlling interests (Note 12)	**1,137**	1,059
Total equity	**4,134**	4,385
Total liabilities and equity	**9,428**	10,304

Commitments and contingencies (Note 33)

On behalf of the Board:

Gordon D. Giffin
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings	–	–	–	(160)	–	(160)	42	(118)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	(25)	(25)	–	(25)
Net gains on derivatives designated as cash flow hedges, net of tax	–	–	–	–	106	106	–	106
Net actuarial gains on defined benefits plans, net of tax	–	–	–	–	(6)	(6)	–	(6)
Intercompany available-for-sale investments	–	–	–	–	11	11	(11)	–
Total comprehensive income				(160)	86	(74)	31	(43)
Common share dividends	–	–	–	(34)	–	(34)	–	(34)
Preferred share dividends	–	–	–	(30)	–	(30)	–	(30)
Changes in non-controlling interests in TransAlta Renewables (Note 4)	–	–	–	(52)	4	(48)	48	–
Effect of share-based payment plans	–	–	1	–	–	1	–	1
Distributions paid, and payable, to non-controlling interests	–	–	–	–	–	–	(172)	(172)
Balance, Dec. 31, 2017	3,094	942	10	(1,209)	489	3,326	1,059	4,385
Impact of change in accounting policy (Note 3)	**–**	**–**	**–**	**(14)**	**–**	**(14)**	**1**	**(13)**
Adjusted balance as at Jan. 1, 2018	**3,094**	**942**	**10**	**(1,223)**	**489**	**3,312**	**1,060**	**4,372**
Net earnings (loss)	**–**	**–**	**–**	**(198)**	**–**	**(198)**	**108**	**(90)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**–**	**–**	**–**	**–**	**43**	**43**	**–**	**43**
Net gains on derivatives designated as cash flow hedges, net of tax	**–**	**–**	**–**	**–**	**(54)**	**(54)**	**–**	**(54)**
Net actuarial gains on defined benefits plans, net of tax	**–**	**–**	**–**	**–**	**15**	**15**	**–**	**15**
Intercompany fair value through other comprehensive income investments	**–**	**–**	**–**	**–**	**(16)**	**(16)**	**16**	**–**
Total comprehensive income				**(198)**	**(12)**	**(210)**	**124**	**(86)**
Common share dividends	**–**	**–**	**–**	**(57)**	**–**	**(57)**	**–**	**(57)**
Preferred share dividends	**–**	**–**	**–**	**(50)**	**–**	**(50)**	**–**	**(50)**
Shares purchased under NCIB	**(35)**	**–**	**–**	**12**	**–**	**(23)**	**–**	**(23)**
Changes in non-controlling interests in TransAlta Renewables (Note 4)	**–**	**–**	**–**	**20**	**4**	**24**	**133**	**157**
Effect of share-based payment plans	**–**	**–**	**1**	**–**	**–**	**1**	**–**	**1**
Distributions paid, and payable, to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(180)**	**(180)**
Balance, Dec.31, 2018	**3,059**	**942**	**11**	**(1,496)**	**481**	**2,997**	**1,137**	**4,134**

(1) Refer to Note 26 for details on components of, and changes in, accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2018**	2017	2016
Operating activities			
Net earnings (loss)	**(90)**	(118)	276
Depreciation and amortization (Note 34)	**710**	708	664
Gain (loss) on sale of assets (Note 4)	**—**	(1)	(1)
Accretion of provisions (Note 21)	**24**	23	20
Decommissioning and restoration costs settled (Note 21)	**(31)**	(19)	(23)
Deferred income tax expense (recovery) (Note 11)	**(34)**	(15)	15
Unrealized (gain) loss from risk management activities	**30**	(48)	58
Unrealized foreign exchange (gain) loss	**28**	22	(1)
Provisions	**7**	(7)	(123)
Asset impairment charges (reversals) (Note 7)	**73**	20	28
Other non-cash items	**147**	175	(242)
Cash flow from operations before changes in working capital	**864**	740	671
Change in non-cash operating working capital balances (Note 30)	**(44)**	(114)	73
Cash flow from operating activities	**820**	626	744
Investing activities			
Additions to property, plant and equipment (Note 17 and 34)	**(277)**	(338)	(358)
Additions to intangibles (Note 19 and 34)	**(20)**	(51)	(21)
Restricted cash (Note 22)	**(35)**	(30)	—
Loan receivable (Note 20)	**1**	(38)	—
Acquisition of renewable energy facilities, net of cash acquired (Note 4)	**(30)**	—	—
Proceeds on sale of property, plant and equipment	**2**	3	6
Proceeds on sale of Wintering Hills facility and Solomon disposition (Note 4)	**2**	478	—
Income tax expense on Solomon disposition (Note 4 and 11)	**—**	(56)	—
Realized gains (losses) on financial instruments	**2**	6	(6)
Decrease in finance lease receivable	**59**	59	56
Other	**(2)**	(3)	2
Change in non-cash investing working capital balances	**(96)**	57	(6)
Cash flow from (used in) investing activities	**(394)**	87	(327)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 22)	**312**	26	(315)
Repayment of long-term debt (Note 22)	**(1,179)**	(814)	(88)
Issuance of long-term debt (Note 22)	**345**	260	361
Dividends paid on common shares (Note 24)	**(46)**	(46)	(69)
Dividends paid on preferred shares (Note 25)	**(40)**	(40)	(42)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4)	**144**	—	162
Repurchase of common shares under NCIB (Note 24)	**(23)**	—	—
Realized gains (losses) on financial instruments	**48**	106	(2)
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(165)**	(172)	(151)
Decrease in finance lease obligations (Note 22)	**(18)**	(17)	(16)
Other	**(31)**	(6)	(3)
Change in non-cash financing working capital balances	**2**	—	—
Cash flow from (used in) financing activities	**(651)**	(703)	(163)
Cash flow from (used in) operating, investing, and financing activities	**(225)**	10	254
Effect of translation on foreign currency cash	**—**	(1)	(3)
Increase (decrease) in cash and cash equivalents	**(225)**	9	251
Cash and cash equivalents, beginning of year	**314**	305	54
Cash and cash equivalents, end of year	**89**	314	305
Cash income taxes paid	**87**	14	27
Cash interest paid	**188**	230	235

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992. Its head office is located in Calgary, Alberta.

I. Generation Segments

The six generation segments of the Corporation are as follows: Canadian Coal, US Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro. The Corporation directly or indirectly owns and operates hydro, wind and solar, natural gas and coal-fired facilities, and related mining operations in Canada, the United States ("US"), and Australia. Revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Canadian Coal segment.

II. Energy Marketing Segment

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

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

III. Corporate

The Corporate segment includes the Corporation's central financial, legal, administrative, investor relation functions and corporate development. Charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on February 26, 2019.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists when the Corporation is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Significant Accounting Policies

A. Revenue Recognition

I. Revenue from Contracts with Customers

The Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018. As a result, the Corporation has changed its accounting policy for revenue recognition, which is outlined below.

The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are active at the date of initial adoption. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to section III below for the accounting policy for prior years.

The majority of the Corporation's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, renewable attributes and byproducts of power generation. The Corporation evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Corporation's performance to date. The Corporation excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Corporation's contracts may contain more than one performance obligation.

Transaction Price

The Corporation allocates the transaction price in the contract to each performance obligation. Transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Corporation's contracts with customers is primarily variable, and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes which are driven by customer or market demand or by the operational ability of the plant; revenues can be dependent upon the variable cost of producing the energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Corporation expects to be entitled to in exchange for transferring the good or service. The Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their relative standalone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition
The nature, timing of recognition of satisfied performance obligations, and payment terms for the Corporation's goods and services are described below:

Good or Service	*Description*
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (i.e., monthly) in an amount representative of availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract Power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal Energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Renewable Attributes	Renewable attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for renewable attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the renewable attributes. Obligations to deliver renewable attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Corporation's Canadian and US coal operations, and the sale of coal to third parties. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

The Corporation recognizes a contract asset or contract liability for contracts where either party has performed. A contract liability is recorded when the Corporation receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Corporation has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Corporation recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

The Corporation recognizes a significant financing component where the timing of payment from the customer differs from the Corporation's performance under the contract and where that difference is the result of the Corporation financing the transfer of goods and services.

Significant Judgments
Identification of performance obligations
Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

Transaction price
In determining the transaction price and estimates of variable consideration, management considers past history of customer usage and capacity requirements, in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of transaction price to performance obligations
The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of performance obligations
The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient can be relied upon in measuring progress toward complete satisfaction of performance obligations. The invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

II. Revenue from Other Sources
Lease revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. 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 the Corporation retains 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.

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

III. Revenue Recognition Policy in Prior Years
The majority of the Corporation's revenues are derived from the sale of physical power, the leasing of power facilities and from energy marketing and trading activities. Revenues are measured at the fair value of the consideration received or receivable.

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

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

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

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

Effective Jan. 1, 2018, the Corporation adopted IFRS 9. In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods. Refer to section III below for information on its prior accounting policy. The Corporation's accounting policies under IFRS 9 are outlined below.

Classification and Measurement

IFRS 9 introduces the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Corporation's business model for the financial asset. All financial assets and financial liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Corporation becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss ("FVTPL"), or at fair value through other comprehensive income ("FVTOCI").

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those that have contractual cash flows arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

The Corporation enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk, and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled or expired.

Financial assets are also derecognized when the Corporation has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows to a third party under a "pass-through" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if TransAlta retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

Financial assets and financial liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

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

Impairment of Financial Assets
TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition, or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Corporation does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information. Forward-looking information utilized includes third-party default rates over time, dependent on credit ratings.

II. Hedges
Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

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

Fair Value Hedges
In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate ("EIR") method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in profit or loss.

Cash Flow Hedges
In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in AOCI must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation
In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

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

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization. Other financial assets are those non-derivative financial assets that are designated as such or that have not been classified as another type of financial asset, and are measured at fair value through OCI. Other financial assets are measured at cost if fair value is not reliably measurable.

Financial assets are assessed for impairment on an ongoing basis and at reporting dates. An impairment may exist if an incurred loss event has arisen that has an impact on the recoverability of the financial asset. Factors that may indicate an incurred loss event and related impairment may exist include, for example, if a debtor is experiencing significant financial difficulty, or a debtor has entered or it is probable that they will enter, bankruptcy or other financial reorganization. The carrying amount of financial assets, such as receivables, is reduced for impairment losses through the use of an allowance account, and the loss is recognized in net earnings.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled or expired.

Financial assets and financial liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

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

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

Hedges

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

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

Fair Value Hedges

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

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

Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivative's cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when the forecasted transaction is no longer expected to occur within the time period specified in the hedge documentation.

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

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

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

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

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

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

F. Inventory
I. Fuel
The Corporation's inventory balance is comprised of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value.

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

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

III. Parts, Materials and Supplies
Parts, materials and supplies are recorded at the lower of cost, measured at moving average costs, and net realizable value.

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

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

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

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

Coal generation	2-12 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	2-12 years
Capital spares and other	2-30 years

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

H. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale, and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

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

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

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

Software	2-7 years
Power sale contracts	5-20 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Corporation assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

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 the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating 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 the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's 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 asset or cash-generating unit ("CGU") to which the asset 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, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

The Corporation has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

The Corporation measures share-based awards compensation expense at grant date fair value and recognizes the expense over the vesting period based on the Corporation's estimate of the number of units that will eventually vest. Any award that vests in installments is accounted for as a separate award with its own distinct fair value measurement.

Compensation expense associated with equity-settled and cash-settled awards are recognized within equity and liability, respectively. The liability associated with cash-settled awards is remeasured to fair value at each reporting date up to, and including, the settlement date, with changes in fair value recognized within compensation expense.

P. Emission Credits and Allowances

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

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

Q. Assets Held for Sale

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

R. Leases

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

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

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

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

Leasing or other contractual arrangements that transfer substantially all of the risks and rewards of ownership to the Corporation are considered finance leases. A leased asset and lease obligation are recognized at the lower of the fair value or the present value of the minimum lease payments. Lease payments are apportioned between interest expense and a reduction of the lease liability. Contingent rents are charged as expenses in the periods incurred. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

S. Borrowing Costs

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

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

T. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used. Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains control.

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

U. Joint Arrangements

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

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

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

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

V. Government Incentives

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

W. Earnings per Share

Basic earnings per share is calculated by dividing net earnings attributable to common shareholders by the weighted average number of common shares outstanding in the year.

Diluted earnings per share is calculated by dividing net earnings attributable to common shareholders, adjusted for the after-tax effects of dividends, interest or other changes in net earnings that would result from potential dilutive instruments, by the weighted average number of common shares outstanding in the year, adjusted for additional common shares that would have been issued on the conversion of all potential dilutive instruments.

X. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed.

Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

Y. Stripping Costs

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

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. 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, capital expenditures, 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, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. 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.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. 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, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Corporation evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Corporation's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2016 to 2018 is found in Notes 7 and 18.

II. Leases

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

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. See Note 11 for further details on the impacts of the Corporation's tax policies.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Project Development Costs
Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized. Information on the write-off of project development costs is disclosed in Note 7(B).

VI. Provisions for Decommissioning and Restoration Activities
TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 21. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision.

VII. Useful Life of PP&E
Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 3(A)(III).

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 28 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 21 with respect to other provisions.

3. Accounting Changes

A. Current Accounting Changes

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), 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. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted.

The Corporation has adopted IFRS 15 with an initial adoption date of Jan. 1, 2018. As a result, the Corporation has changed its accounting policy for revenue recognition, which is outlined in Note 2(A).

The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are not completed contracts at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* ("IAS 18"), which is outlined in Note 2(A)(iii).

The Corporation recognized the cumulative impact of the initial application of the standard in the deficit as at Jan. 1, 2018. Applying the significant financing component requirements to a specific contract resulted in an increase to the contract liability of $17 million, a decrease in deferred income tax liabilities of $4 million and an increase to the deficit of $13 million. IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer (“significant financing component”). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. The application of the significant financing component requirement results in the recognition of interest expense over the financing period and a higher amount of revenue.

Additionally, the Corporation no longer recognizes revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of its gas plants , as it was determined under IFRS 15 that the Corporation does not obtain control of the customer-supplied natural gas.

Refer to the discussion in Note 2(A) and in Note 5 for a breakdown of the Corporation's revenues from contracts with customers and revenues from other sources.

The following tables summarize the financial statement line items impacted by adopting IFRS 15 as at and for the year ended Dec. 31, 2018:

Condensed Consolidated Statement of Earnings (Loss)

Year ended Dec. 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Revenues	2,253	(4)	2,249
Fuel, carbon costs and purchased power	(1,109)	9	(1,100)
Net interest expense	(243)	(7)	(250)
Net earnings impact	(88)	(2)	(90)

Condensed Consolidated Statements of Financial Position

As at Dec. 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Deferred income tax liabilities	505	(4)	501
Contract liability	68	19	87
Deficit	(1,481)	(15)	(1,496)

There were no impacts to the statement of cash flows as a result of adopting IFRS 15.

II. IFRS 9 *Financial Instruments*

Effective Jan. 1, 2018, the Corporation adopted IFRS 9, which introduces new requirements for:

- the classification and measurement of financial assets and liabilities;
- the recognition and measurement of impairment of financial assets; and
- general hedge accounting.

In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods. The impact of adopting IFRS 9 was recognized in the deficit at Jan. 1, 2018. While the Corporation had no direct impact of adopting IFRS 9, a $1 million increase in the deficit resulted from the increase in equity attributable to non-controlling interests due to IFRS 9 impacts at TransAlta Renewables Inc. ("TransAlta Renewables").

The Corporation's accounting policies under IFRS 9 are outlined in Note 2(C) and the key impacts are outlined below. For more information on the Corporation's accounting policies under IAS 39 for the period ended Dec. 31, 2017, refer to note 2 of the Corporation's 2017 annual consolidated financial statements.

a. Classification and Measurement

IFRS 9 introduces the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Corporation's business model for the financial asset. All financial assets and financial liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Corporation becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at FVTPL, or at FVTOCI. Refer to Note 2 (C) for further details.

The Corporation's management reviewed and assessed the classifications of its existing financial instruments as at Jan. 1, 2018, based on the facts and circumstances that existed at that date, as shown below. None of the reclassifications had a significant impact on the Corporation's financial position, earnings (loss), other comprehensive income (loss) or total comprehensive income (loss) after the date of initial application.

Financial instrument	IAS 39 category	IFRS 9 classification
Cash and cash equivalents	Loans and receivables	Amortized cost
Restricted cash	Loans and receivables	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost
Long-term portion of finance lease receivables	Loans and receivables	Amortized cost
Loan receivable (other assets)	Loans and receivables	Amortized cost
Risk management assets (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management assets (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost
Dividends payable	Other financial liabilities	Amortized cost
Risk management liabilities (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management liabilities (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Credit facilities and long-term debt	Other financial liabilities	Amortized cost

b. Impairment of Financial Assets
IFRS 9 introduces a new impairment model for financial assets measured at amortized cost as well as certain other instruments. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk.

The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon application of IFRS 9 and no loss allowance was recognized.

c. General Hedge Accounting
IFRS 9 retains the three types of hedges from IAS 39 (fair value hedges, cash flow hedges and hedges of a net investment in a foreign operation), but increases flexibility as to the types of transactions that are eligible for hedge accounting.

The effectiveness test of IAS 39 is replaced by the principle of an "economic relationship", which requires that the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. Additionally, retrospective hedge effectiveness testing is no longer required under IFRS 9.

In accordance with IFRS 9's transition provisions for hedge accounting, the Corporation has applied the IFRS 9 hedge accounting requirements prospectively from the date of initial application on Jan. 1, 2018, and comparative figures have not been restated. The Corporation's qualifying hedging relationships under IAS 39 in place as at Jan. 1, 2018 also qualified for hedge accounting in accordance with IFRS 9, and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018. As the critical terms of the hedging instruments match those of their corresponding hedged items, all hedging relationships continue to be effective under IFRS 9's effectiveness assessment. The Corporation has not designated any hedging relationships under IFRS 9 that would not have met the qualifying hedge accounting criteria under IAS 39. Further details of the Corporation's hedging activities are disclosed in Notes 14 and 15.

The Corporation's risk management objective and strategy, including risk management instruments and their key terms, are detailed in Notes 15A and 15C.

In certain cases, the Corporation purchases non-financial items in a foreign currency, for which it may enter into forward contracts to hedge foreign currency risk on the anticipated purchases. Both IAS 39 and IFRS 9 require hedging gains and losses to be basis adjusted to the initial carrying amount of non-financial hedged items once recognized (such as PP&E), but under IFRS 9, these adjustments are no longer considered reclassification adjustments and do not affect OCI. Under IFRS 9, these amounts will be directly transferred to the asset and will be reflected in the statement of changes in equity as a reclassification from AOCI.

The application of IFRS 9 hedge accounting requirements has no other impact on the results and financial position of the Corporation for the current or prior years.

III. Change in Estimates - Useful Lives
As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(O), the Corporation has adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. In addition, on Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2018, increased by approximately $38 million (2017 - $58 million). The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 4(A) for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2018. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 was shut down two years early, the Canadian federal Minister of Environment & Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the life of Sundance Unit 2 to 2021 (see Note 4(A) for further details). As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, decreased in total by approximately $4 million. However, in the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment loss for the remaining net book value of the asset (see Note 4(A) and Note 7 for further details).

B. 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 16 *Leases.* In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. For lessors, the accounting remains essentially unchanged.

IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019. The standard is required to be adopted either retrospectively or using a modified retrospective approach. On transition, TransAlta has elected to apply IFRS 16 using the modified retrospective approach effective Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and low value leases;
- Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;
- Adjusting the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right-of-use assets at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

The Corporation has substantially completed its assessment of existing operating leases. The Corporation estimates that we will recognize right-of-use lease assets and related lease liabilities for existing operating leases where we are the lessee in the range of $42 million to $52 million. These changes will be partially offset by the derecognition of a finance lease asset and a finance lease liability related to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16.

C. Comparative Figures

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

4. Significant Events

A. Transition to Clean Power in Alberta

I. Alberta Renewable Energy Program Project - Windrise

In the fourth quarter of 2018, TransAlta's 207 MW Windrise wind project was selected by the Alberta Electric System Operator ("AESO") as one of the three successful projects in the third round of the Renewable Electricity Program. The Windrise facility, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately $270 million and is targeted to reach commercial operation during the second quarter of 2021.

II. Gas Supply for Coal-to-Gas Conversions

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 percent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). Tidewater Midstream and Infrastructure Ltd. ("Tidewater") will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline will provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately $90 million. Construction of the pipeline commenced in November 2018 and the Pioneer Pipeline is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals, which are expected to be received in the first half of 2019.

The decision to work with Tidewater advances the time frame for the construction of the Pioneer Pipeline and permits the acceleration of plant conversions. TransAlta remains of the view that having at least two pipelines supplying natural gas would reduce operational risks and continues to advance discussions with other parties to construct additional pipelines to meet the remaining gas supply requirements for the facilities.

III. Sundance and Keephills Units 1 and 2 Coal-to-Gas Conversion Strategy
On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. During 2018, the Corporation mothballed and retired the following Sundance Units:

- retired Sundance Unit 1 on Jan. 1, 2018;
- retired Sundance Unit 2 on July 31, 2018;
- temporarily mothballed Sundance Unit 3 on April 1, 2018, for a period of up to two years; and
- temporarily mothballed Sundance Unit 5 on April 1, 2018, for a period of up to one year, which has now been extended to two years.

TransAlta is no longer planning to temporarily mothball Sundance Unit 4 and will perform maintenance during the first half of 2019.

On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The regulations provide rules for new gas-fired electricity facilities, as well as specific provisions for coal-to-gas conversions. In addition to extending their operating lives, the benefits of converting units to gas generation include: significantly lowering carbon emissions and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility. TransAlta expects to convert some or all of its Sundance Units 3 to 6 and Keephills Units 1 to 3 in the 2020 to 2023 period.

IV. Sundance Units 1 and 2
Canadian federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 was shut down two years early, the federal Minister of Environment & Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This provided the Corporation with the flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market. However, in July 2018, TransAlta retired Sundance Unit 2. This decision was driven largely by Sundance Unit 2's age, size and short useful life relative to other units, and the capital requirements needed to return the unit to service.

Sundance Units 1 and 2 collectively made up 560 MW of the 2,141 MW capacity of the Sundance power plant, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expired on Dec. 31, 2017.

In the third quarter of 2018, the Corporation recognized an impairment charge of $38 million ($28 million after-tax) relating to the retirement of Sundance Unit 2. During the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of $20 million ($15 million after-tax) due to the Corporation’s decision to early retire Sundance Unit 1. See Note 7 for further details.

B. Kent Hills 3 Wind Project

During 2017, a subsidiary of TransAlta Renewables, Kent Hills Wind LP ("KHWLP"), entered into a long-term contract with New Brunswick Power Corporation (“NB Power”) for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 expansion wind project. At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035, matching the life of the Kent Hills 2 and Kent Hills 3 wind projects.

On Oct. 19, 2018, TransAlta Renewables announced that the expansion is fully operational, bringing total generating capacity of the Kent Hills wind farm to 167 MW.

C. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire two construction-ready projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 2018,and the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the Antrim acquisition to close in early 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables and a $25 million promissory note receivable and are estimated to be US$240 million. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs using its existing liquidity and tax equity.

During the year ended Dec. 31, 2018, TransAlta Renewables funded approximately $61 million (US$48 million) of construction costs. On Jan. 2, 2019, TransAlta Renewables funded an additional $45 million (US$33 million) of construction costs.

D. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

On May 31, 2018, TransAlta Renewables acquired from a subsidiary of the Corporation an economic interest in the 50 MW Lakeswind wind farm in Minnesota and 21 MW of solar projects located in Massachusetts ("Mass Solar") through the subscription of tracking preferred shares of a subsidiary of the Corporation. In addition, TransAlta Renewables acquired from a subsidiary of the Corporation ownership of the 20 MW Kent Breeze wind farm located in Ontario. The total purchase price for the three assets was approximately $166 million, including the assumption of $62 million of tax equity obligations and project debt, for net cash consideration of $104 million. The Corporation continues to operate these assets on behalf of TransAlta Renewables.

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar, to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge, of which $11 million was recorded against PP&E and $1 million against intangibles. See Note 7 for further details.

E. TransAlta Renewables Closes $150 Million Offering of Common Shares

On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters (the "Offering"). The common shares were issued at a price of $12.65 per common share for gross proceeds of approximately $150 million ($144 million of net proceeds).

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility is to be used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(C) above.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 12 for further details of TransAlta's ownership of TransAlta Renewables.

F. $345 Million Financing

On July 20, 2018, the Corporation monetized the payments under the OCA with the Government of Alberta by closing a $345 million bond offering through its indirect wholly owned subsidiary, TransAlta OCP LP ("TransAlta OCP"). The offering was a private placement that was secured by, among other things, a first ranking charge over the OCA payments payable by the Government of Alberta. The amortizing bonds bear interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The bonds have a rating of BBB, with a Stable trend, by DBRS. Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

G. Early Redemption of $400 Million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of$400 million. The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest. See Note 22 for further details.

H. Normal Course Issuer Bid

On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.86 per cent of issued and outstanding common shares as at March 2, 2018. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Common shares purchased under the NCIB are cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018, and ends on March 13, 2019, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than102,039 common shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 common shares for the six months ended February 28, 2018) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million. See Note 24 for further details. Further transactions, if any, under the NCIB will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

I. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US $500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense. See Note 22 for further details.

J. Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective March 31, 2018.

This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective March 31, 2018. Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018. The Corporation is disputing the termination payment it received. The Balancing Pool excluded certain mining assets that the Corporation believes should be included in the net book value calculation for an additional termination payment of $56 million. The dispute is currently proceeding through the PPA arbitration process.

K. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited

On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidiary of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the power station has not reached commercial operation within a specified time period. FMG continues to be of the view that South Hedland Power Station has yet to achieve commercial operation.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation is taking all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized. The South Hedland Power Station has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA.

L. Re-acquisition of Solomon Power Station

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action in the Supreme Court of Western Australia to recover all, or a significant portion of, this amount from FMG.

M. TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, KHWLP, closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds was used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project. The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers, Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP. Proceeds of $31 million are classified as restricted cash as at Dec. 31, 2018, relating to the construction reserve account, and will be released upon certain conditions being met, which are expected to be finalized in Q1 2019.

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million, which included the principal of $191 million, an early redemption premium of $6 million and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

N. Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of its Series E Preferred Shares into Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and the dividend rate remains fixed for the subsequent five-year period. See Note 25 for further details.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of its Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and the dividend remains fixed for the subsequent five-year period. See Note 25 for further details.

O. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an agreement with the Government of Alberta (the "Government") on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation will receive annual cash payments of approximately $37 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include: maintaining prescribed spending on investment and investment-related activities in Alberta; maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels); and maintaining spending on programs and initiatives to support the communities surrounding the plants, the employees of the Corporation negatively impacted by the phase-out of coal generation and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

The Corporation also entered into a Memorandum of Understanding with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas fired conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market to be developed for the Province of Alberta.

P. Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool are seeking to set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. This application is scheduled to be heard from Feb. 27, 2019 to Mar. 1, 2019.

Q. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP, which holds the Corporation's interest in the Poplar Creek cogeneration facility, completed the private placement of a $202.5 million aggregate principal amount of senior secured floating rate bonds. The bonds, which mature on Dec. 31, 2030, are secured by a first ranking charge over the equity interests of the issuer of such bonds. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points.

R. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was effective on Jan. 1, 2017, and, in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate, effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. effective Dec. 31, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

The NUG Contract provided the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations. Further details on the NUG Contract and its impact to these financial statements can be found in Note 9(C).

S. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for net proceeds to the Corporation of $61 million.

T. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables' indirect wholly owned subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

U. Investment in, and Acquisition by, TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm and Ragged Chute Hydro Facility (the "Canadian Assets")

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Québec.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million and issued a $215 million convertible unsecured subordinated debenture. On Nov. 9, 2017, TransAlta Renewables repaid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. The convertible debenture was scheduled to mature on Dec. 31, 2020.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million through the issuance of a non-interest bearing loan payable to the Corporation.

The acquisition of the Canadian Assets was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the Canadian Assets' assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at Nov. 30, 2016, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $38 million in 2016.

5. Revenue

A. Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and green attributes, leasing of power facilities, and from energy marketing and trading activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	517	9	224	91	206	132	—	—	1,179
Revenue from leases[(1)]	68	—	—	68	27	7	—	—	170
Revenue from derivatives	(1)	115	4	—	(20)	—	67	—	165
Government incentives	—	—	—	—	16	—	—	—	16
Revenue from other[(2)]	328	318	4	6	53	17	—	(7)	719
Total revenue	912	442	232	165	282	156	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	38	9	—	—	18	—	—	—	65
Over time	479	—	224	91	188	132	—	—	1,114
Total revenue from contracts with customers	517	9	224	91	206	132	—	—	1,179

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases. 2017 - $247 million, 2016 - $221 million.
(2) Includes merchant revenue and other miscellaneous.

B. Contract Balances

The Corporation has recognized the following revenue-related contract assets and liabilities:

Contract liabilities	
Dec. 31, 2017	62
IFRS 15 transition adjustment	17
Amounts transferred to revenue included in opening balance	(10)
Consideration received	13
Increases due to interest accrued and expensed during the period	6
Amounts transferred to payables	(1)
Dec. 31, 2018	**87**

Contract liabilities are primarily comprised of consideration received from the Corporation's Keephills Unit 3 joint operation partner for which the Corporation has a future obligation to transfer goods and services to the partner under the contract. Consideration received is dependent upon the Corporation's mine capital replacement plan and revenue is recognized as the Corporation satisfies its performance obligations under the contract of being available to deliver coal and the delivery of coal.

C. Remaining Performance Obligations

As required by the new revenue standard, the Corporation is required to disclose the aggregate amount of the transaction price allocated to remaining performance obligation (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period. The following disclosures exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify

for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

Additionally, in many of the Corporation's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Corporation's influence. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved. Further, adjustments to revenue to recognize a significant financing component in a contract are not included in the amounts disclosed for remaining performance obligations.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Corporation from its contractual portfolio.

Canadian Coal
At Dec. 31, 2018, the Corporation has PPAs with the Balancing Pool for capacity and electricity from two of its coal plants, as dispatched, with contract end dates of Dec. 31, 2020. All generation produced is delivered to the customer. Certain sources of revenue under one PPA contract are accounted for as a lease, and are excluded from these disclosures. Pricing is comprised of multiple components, of both fixed and variable nature, consisting of a capacity payment based on a return of capital, availability payments (from or to the customer) based on the 30-day rolling average pool price and actual availability of the plant as compared to targeted availability specified in the PPAs, recovery of regulatory pass-through costs, and payments for delivery of energy based on the variable cost of producing the energy. Energy-related payments are variable depending on output from the plant, which is dependent upon market demand and the operational ability of the plant. Revenues are generally recognized over time, on a monthly basis. Future revenues that are based upon variable consideration are considered to be fully constrained and are excluded from these disclosures.

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal plants. The contracts range in duration from one to three years. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

The Corporation has a contract at its Alberta coal mine that requires it to be available to deliver coal as required, and to provide byproduct disposal services for the plant. The duration of the contract is largely dependent upon the Corporation's coal-to-gas transition plans and decisions. Pricing terms are based on actual costs incurred to provide the coal, and will vary over the life of the contract. Revenue will be recognized on the basis of the costs incurred and based on volumes of coal delivered, which are variable and depend upon market demand for electricity, which is subject to factors outside of the Corporation's control. Accordingly, revenues related to remaining performance obligations associated with this component of the contract are excluded from these disclosures as they are variable and considered to be fully constrained. The customer also funds a portion of the required mine capital as part of the transaction price, which the Corporation has determined constitutes a significant financing component. Revenues are dependent upon the Corporation's mine capital replacement plan and the recoveries, along with the significant financing component, and are amortized into revenue as the Corporation satisfies its performance obligations of being available to deliver coal and the delivery of coal. The significant financing component of these revenues is excluded from these disclosures.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $330 million, of which the Corporation expects to recognize approximately $245 million in total over the next two fiscal years and on average, between approximately $7 million to $10 million annually thereafter for the duration of the contracts.

US Coal
The Corporation's long-term contract for the sale of electricity produced at its US Coal plant is considered a derivative and is designated as an all-in-one hedge. Accordingly, while revenues for electricity delivered to the customer are recognized pursuant to the contractual terms, the revenues are not accounted for under IFRS 15 and the contract has been excluded from any required IFRS 15 disclosures.

The Corporation also has a contract for the sale of byproducts of coal combustion from its US Coal plant. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

Canadian Gas
At Dec. 31, 2018, the Corporation has contracts with customers to deliver energy services from one of its gas plants in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. The following is a summary of the key terms:

The energy supply agreements require specified amounts of steam to be delivered to each customer, and have pricing terms that include fixed and variable charges for electricity, capacity and steam, as well as a true-up based on contractual minimum volumes of steam. The steam reconciliation is based on an estimate of the customer's steam volume taken and the contractual minimum volume, and various factors including the annual average market price of electricity and the average locally posted and index prices of natural gas, as well as transportation. For steam volumes not taken by the customer, a revenue-sharing mechanism provides for sharing of revenues earned by the Corporation using that steam to generate and sell electricity. Capacity and electricity pricing vary from contract to contract and are subject to annual indexation at varying rates. Electricity and steam delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control, These variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

At the same gas plant, the Corporation has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers, and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Corporation's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2018, the Corporation has contracts with customers to deliver steam, hot water and chilled water from one of its other gas plants in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $25 million in total, of which the Corporation expects to be on average, between approximately $4 million to $6 million annually thereafter for the duration of the contracts.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to some of the Corporation's other gas facilities' contracts in Ontario; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas
At Dec. 31, 2018, the Corporation has PPAs with customers to deliver electricity from its gas plants located in Australia. One contract is considered to be a lease and is excluded from these disclosures. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2021 to 2042.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $2,280 million, of which the Corporation expects to recognize approximately $230 million in total over the next three fiscal years and on average, between approximately $80 million to $110 million annually thereafter for the duration of the contracts.

Wind and Solar
At Dec. 31, 2018, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from two wind farms located in Alberta and Minnesota, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain

pricing subject to annual escalations for inflation. The Corporation expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024 and 2034. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchaser over the remaining terms of the contracts, from 2019 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $9 million, of which the Corporation expects to recognize between approximately $1 million to $2 million annually through to contract expiry.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to wind energy contracts in Ontario, New Brunswick, Quebec and Wyoming, and for all solar contracts; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Hydro

At Dec. 31, 2018, the Corporation has a PPA with the Balancing Pool to provide the capacity of 12 hydro plants throughout the province of Alberta. The capacity payment is fixed on an annual basis. As part of the PPA, the Corporation also has a financial obligation to the Balancing Pool determined on the basis of notional quantities of electricity delivered and the pool price for the period. The Corporation expects to recognize revenue as it makes capacity available to the customer until completion of the contract term at Dec. 31, 2020. The Corporation also has contracts for blackstart services at specific hydro plants and a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which all conclude within 2020.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $130 million, which the Corporation expects to recognize over the next two fiscal years.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to all hydro energy contracts in Ontario, British Columbia and Washington; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2018**		2017		2016	
	Fuel and purchased power	**Operations, maintenance and administration**	Fuel and purchased power	Operations, maintenance and administration	Fuel and purchased power	Operations, maintenance and administration
Fuel[1]	**656**	**—**	685	—	665	—
Coal inventory writedown (recovery)	**—**	**—**	—	—	(4)	—
Purchased power	**210**	**—**	162	—	143	—
Mine depreciation	**136**	**—**	73	—	63	—
Salaries and benefits[1]	**98**	**245**	96	248	96	249
Other operating expenses	**—**	**270**	—	269	—	240
Total	**1,100**	**515**	1,016	517	963	489

(1) $90 million in both 2017 and 2016 was reclassified from fuel to salaries and benefits to be consistent with the 2018 classification.

7. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the

Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. Alberta Merchant CGU

During 2018, 2017 and 2016, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan, the future design parameters of the Alberta electricity market, and federal policies on the carbon levy and greenhouse gas ("GHG") emissions. Economic conditions also contributed to continued oversupply conditions and depressed market prices throughout 2015 to 2017. The Corporation assessed whether these factors, and events arising during the latter part of 2016, which are more fully discussed below, presented an indicator of impairment for its Alberta Merchant CGU. In consideration of the composition of this CGU, the Corporation determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, the Corporation did not perform an in-depth impairment analysis for any of these years, but for all years, a sensitivity analysis associated with these factors was performed to confirm the continued existence of adequate excess of estimated recoverable amount over book value. This analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU in each of 2018, 2017 and 2016, due to the Corporation's large merchant renewable fleet in the province.

I. 2018

Sundance Unit 2

In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on July 31, 2018. Discounting did not have a material impact.

Lakeswind and Kent Breeze

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 4(D)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (See Note 17 and 19).

II. 2017

Sundance Unit 1

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintained the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU to 2021.

III. 2016

Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million (see Note 4(S)). In connection with this sale, the Wintering Hills assets were accounted for as held for sale at Dec. 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal in 2016.

B. Project Development Costs

During 2018, the Corporation wrote off $23 million in project development costs related to projects that are no longer proceeding.

8. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases associated with the Fort Saskatchewan cogeneration facility and the Poplar Creek cogeneration facility are as follows:

As at Dec. 31	2018		2017	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	30	29	68	66
Second to fifth years inclusive	80	74	110	82
More than five years	140	112	140	126
	250	215	318	274
Less: unearned finance lease income	35	—	44	—
Total finance lease receivables	**215**	**215**	274	274

	2018	2017
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 13)	24	59
Long-term portion of finance lease receivables	191	215
	215	274

9. Net Other Operating Expense (Income)

Net other operating expense (income) includes the following:

Year ended Dec. 31	2018	2017	2016
Alberta Off-Coal Agreement	(40)	(40)	—
Termination of the Sundance B and C PPAs	(157)	—	—
Mississauga cogeneration facility NUG Contract	—	(9)	(191)
Insurance recoveries	(7)	—	(3)
Restructuring provision	—	—	1
Net other operating expense (income)	**(204)**	(49)	(193)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2020. In July 2018, the Corporation obtained financing against the OCA payments (See Note 4(O) and 22).

B. Termination of the Sundance B and C PPAs

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool of the termination of the Sundance B and C PPAs effective March 31, 2018, and received a termination payment of $157 million during the first quarter of 2018. See Note 4(J) for further details.

C. Mississauga Cogeneration Facility Contract

2016

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the IESO for its Mississauga cogeneration facility. The contract was effective on Jan. 1, 2017. The Corporation has agreed to terminate the prior contract with the IESO early, which would have otherwise terminated in December 2018.

As a result of the NUG Contract, the Corporation recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling approximately $16 million. The Corporation also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. The Corporation released and recognized in earnings unrealized pre-tax net losses of $14 million from AOCI due to cash flow hedges de-designated for accounting purposes.

2017

During the fourth quarter of 2017, the Corporation renegotiated the facility's land lease agreement at a lower cost than previously estimated in 2016, and accordingly, recognized a gain of $9 million.

2018

In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. effective Jan. 1, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

D. Insurance Recoveries

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related insurance proceeds for the tower fire at Wyoming Wind and a $1 million claim related to equipment repairs within Canadian Coal. There were no insurance recoveries in 2017.

During 2016, the Corporation received $3 million in insurance recoveries, of which $2 million related to business interruption insurance claims and $1 million related to claims for replacement and refurbishment of equipment for certain wind facilities.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2018**	2017	2016
Interest on debt	**184**	218	218
Interest income	**(11)**	(7)	(2)
Capitalized interest (Note 17)	**(2)**	(9)	(16)
Loss on redemption of bonds (Note 22)	**24**	6	1
Interest on finance lease obligations	**3**	3	3
Credit facility fees, bank charges and other interest	**13**	18	19
Keephills 1 outage interest (reversals) (Note 4(P))	**—**	—	(10)
Other[(1)]	**15**	(3)	(4)
Accretion of provisions (Note 21)	**24**	21	20
Net interest expense	**250**	247	229

(1) During 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable and approximately $7 million for the significant financing component required under IFRS 15 (see Note 3).

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2018	2017	2016
Earnings before income taxes	**(96)**	(54)	314
Net earnings attributable to non-controlling interests not subject to tax	**(19)**	(35)	(109)
Adjusted earnings before income taxes	**(115)**	(89)	205
Statutory Canadian federal and provincial income tax rate (%)	**26.8**	26.8	26.7
Expected income tax expense (recovery)	**(31)**	(24)	55
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(3)**	(11)	(16)
Deferred income tax expense related to temporary difference on investment in subsidiary	**—**	—	11
Writedown (reversal of writedown) of deferred income tax assets	**27**	(15)	(10)
Statutory and other rate differences	**—**	110	1
Other	**1**	4	(3)
Income tax expense (recovery)	**(6)**	64	38
Effective tax rate (%)	**5**	72	19

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2018	2017	2016
Current income tax expense[(1)]	**28**	79	23
Adjustments in respect of deferred income tax of previous years	**—**	—	(3)
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(61)**	(110)	16
Deferred income tax expense related to temporary difference on investment in subsidiary[(2)]	**—**	—	11
Deferred income tax expense resulting from changes in tax rates or laws[(3)]	**—**	110	1
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[(4)]	**27**	(15)	(10)
Income tax expense (recovery)	**(6)**	64	38

Year ended Dec. 31	2018	2017	2016
Current income tax expense	**28**	79	23
Deferred income tax expense (recovery)	**(34)**	(15)	15
Income tax expense (recovery)	**(6)**	64	38

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon Power Station on Nov. 1, 2017.
(2) In 2016, reorganizations of certain TransAlta subsidiaries were completed in connection with the New Richmond project financing and the disposition of the Canadian Assets to TransAlta Renewables. The reorganizations resulted in the recognition of deferred tax liabilities of $3 million and $8 million, respectively. The deferred tax liabilities had not been recognized previously, as prior to the reorganizations, the taxable temporary differences were not expected to reverse in the foreseeable future.
(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act, *which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income. 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016.*
(4) During the year ended Dec. 31, 2018, the Corporation recorded a writedown of deferred income tax assets of $27 million (2017 - $15 million writedown reversal, 2016 - $10 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2037 for losses generated prior to 2018.

B. Consolidated Statements of Changes in Equity

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

Year ended Dec. 31	2018	2017	2016
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(12)**	(108)	51
Net impact related to net investment hedges	**—**	(7)	16
Net actuarial gains (losses)	**5**	(4)	4
Income tax expense reported in equity	**(7)**	(119)	71

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2018	2017
Net operating loss carryforwards	**547**	541
Future decommissioning and restoration costs	**113**	117
Property, plant and equipment	**(896)**	(1,009)
Risk management assets and liabilities, net	**(145)**	(160)
Employee future benefits and compensation plans	**68**	74
Interest deductible in future periods	**48**	50
Foreign exchange differences on US-denominated debt	**35**	42
Deferred coal revenues	**23**	16
Other deductible temporary differences	**—**	22
Net deferred income tax liability, before writedown of deferred income tax assets	**(207)**	(307)
Writedown of deferred income tax assets	**(266)**	(218)
Net deferred income tax liability, after writedown of deferred income tax assets	**(473)**	(525)

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

As at Dec. 31	2018	2017
Deferred income tax assets(1)	**28**	24
Deferred income tax liabilities	**(501)**	(549)
Net deferred income tax liability	**(473)**	(525)

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

D. Contingencies

As of Dec. 31, 2018, the Corporation had recognized a net liability of nil (2017 - $4 million) related to uncertain tax positions.

12. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2018
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.1% - Public shareholders
Kent Hills Wind LP(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind farm located in New Brunswick.

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables.

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders may elect to automatically reinvest monthly dividends into additional common shares of the Corporation.

As a result of the conversion of Class B shares, the DRIP and the transactions described in Note 4, the Corporation's share of ownership and equity participation in TransAlta Renewables has fluctuated since its formation as follows:

Period	**Ownership and voting rights percentage**	**Equity participation percentage**
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9

Year ended Dec. 31	**2018**	2017	2016
Revenues	**462**	459	259
Net earnings	**241**	13	1
Total comprehensive income	**281**	(24)	40
Amounts attributable to the non-controlling interests:			
Net earnings	**94**	11	2
Total comprehensive income	**110**	—	18
Distributions paid to non-controlling interests	**79**	85	83

As at Dec. 31	**2018**	**2017**
Current assets	**250**	145
Long-term assets	**3,497**	3,483
Current liabilities	**(159)**	(356)
Long-term liabilities	**(1,192)**	(1,075)
Total equity	**(2,396)**	(2,197)
Equity attributable to non-controlling interests	**(961)**	(812)
Non-controlling interests' share (per cent)	**39.1**	36.0

B. TA Cogen

Year ended Dec. 31	2018	2017	2016
Results of operations			
Revenues	**185**	175	274
Net earnings	**29**	61	211
Total comprehensive income	**29**	61	258
Amounts attributable to the non-controlling interest:			
Net earnings	**14**	31	105
Total comprehensive income	**14**	31	128
Distributions paid to Canadian Power Holdings Inc.	**86**	87	68

As at Dec. 31	2018	2017
Current assets	**82**	193
Long-term assets	**354**	404
Current liabilities	**(54)**	(73)
Long-term liabilities	**(28)**	(26)
Total equity	**(354)**	(498)
Equity attributable to Canadian Power Holdings Inc.	**(176)**	(247)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables

As at Dec. 31	2018	2017
Trade accounts receivable	**597**	693
Mississauga recontracting receivable	**—**	108
Net trade receivables	**597**	801
Promissory note receivable[1]	**25**	—
Collateral paid (Note 15)	**105**	67
Current portion of finance lease receivables (Note 8)	**24**	59
Current portion of loan receivable (Note 20)	**—**	5
Income taxes receivables	**5**	1
Trade and other receivables	**756**	933

(1) The promissory note receivable relates to funding provided for the Antrim wind development project (see Note 4(C) for further details).

14. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost (see Note 2 (C)). The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2018

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Total
Financial assets					
Cash and cash equivalents(1)	–	–	89	–	89
Restricted cash	–	–	66	–	66
Trade and other receivables	–	–	731	25	756
Long-term portion of finance lease receivables	–	–	191	–	191
Risk management assets					
Current	60	86	–	–	146
Long-term	629	33	–	–	662
Other assets	–	–	37	15	52
Financial liabilities					
Accounts payable and accrued liabilities	–	–	497	–	497
Dividends payable	–	–	58	–	58
Risk management liabilities					
Current	1	89	–	–	90
Long-term	1	40	–	–	41
Credit facilities, long-term debt and finance lease obligations(2)	–	–	3,267	–	3,267

(1) Includes cash equivalents of nil.
(2) Includes current portion.

Carrying value as at Dec. 31, 2017

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents(1)	–	–	314	–	314
Restricted cash	–	–	30	–	30
Trade and other receivables	–	–	933	–	933
Long-term portion of finance lease receivables	–	–	215	–	215
Risk management assets					
Current	82	137	–	–	219
Long-term	638	46	–	–	684
Other assets	–	–	33	–	33
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	595	595
Dividends payable	–	–	–	34	34
Risk management liabilities					
Current	8	93	–	–	101
Long-term	2	38	–	–	40
Credit facilities, long-term debt and finance lease obligations(2)	–	–	–	3,707	3,707

(1) Includes cash equivalents of nil.
(2) Includes current portion.

B. Fair Value of 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 that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

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

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

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

b. Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Corporation's 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, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques 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.

The Corporation also has various commodity 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.

The Corporation has a Commodity Exposure Management Policy, that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This 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 the Corporation's risk management department. Level III fair values are calculated within the Corporation's 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.

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at Dec. 31	**2018**		2017	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**801**	+116 -116	853	+130 -130
Long-term power sale - Alberta	**4**	+1 -1	(1)	+2 -2
Unit contingent power purchases	**18**	+4 -4	44	+7 -9
Structured products - Eastern US	**6**	+5 -5	17	+8 -7
Long-term wind energy sale - Eastern US	**(39)**	+21 -21	—	—
Others	**4**	+3 -3	5	+9 -9

i. Long-Term Power Sale - US

The Corporation has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2020, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2018, are US$20-US$35 (Dec. 31, 2017 - US$25-US$34). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2017 - US$6) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2017 to Dec. 31, 2018, the base fair value and the sensitivity values have increased by approximately $62 million and $9 million, respectively.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as FVTPL.

For periods beyond 2023, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power prices per MWh used in determining the Level III base fair value at Dec. 31, 2018, are $40 (Dec. 31, 2017 - $63 -$67). The sensitivity analysis has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. Unit Contingent Power Purchases

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as FVTPL.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2018, are nil (Dec. 31, 2017 - nil) and 2.2 per cent to 16.9 per cent (Dec. 31, 2017 – 2.2 per cent to 2.8 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.1 per cent to 1.9 per cent (Dec. 31, 2017 - 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 27.3 per cent (Dec. 31, 2017 - 7.8 per cent and 10.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2018, are 75 per cent to 109 per cent and 63 per cent to 104 per cent (Dec. 31, 2017 – 75 per cent to 159 per cent and 71 per cent to 88 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 4 per cent to 7 per cent (Dec. 31, 2017 - 7 per cent) and a change in non-standard shape factors of approximately 4 per cent to 9 per cent (Dec. 31, 2017 - 6 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2018, are 25 per cent to 84 per cent and 70 per cent (Dec. 31, 2017 – 18 per cent to 54 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 37 per cent to 49 per cent and 30 per cent, respectively (2017 - 27 per cent to 32 per cent and 10 per cent, respectively).

v. Long-Term Wind Energy Sale - Eastern US

In relation to the acquisition of Big Level (See Note 4(C)), the Corporation has a long-term contract for differences whereby the Corporation receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. Commercial operation of the facility is expected to occur in the second half of 2019, with the contract extending for 15 years after commercial operation. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2023 and 2022, respectively. Forward power and REC price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2018, are US$42-US$68 and US$7-US$8, respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent, a change in energy prices of US$6 and a change in REC prices of US$1 as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2018, are as follows: Level I - $3 million net asset (Dec. 31, 2017 - $1 million net liability), Level II - $19 million net liability (Dec. 31, 2017 - $42 million net liability) and Level III - $695 million net asset (Dec. 31, 2017 - $771 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2018, are primarily attributable to the settlement of contracts, partially offset by favourable foreign exchange rates.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2018 and 2017, respectively:

	Year ended Dec. 31, 2018			Year ended Dec. 31, 2017		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**719**	**52**	**771**	726	32	758
Changes attributable to:						
Market price changes on existing contracts	**(7)**	**(9)**	**(16)**	100	(2)	98
Market price changes on new contracts	**—**	**4**	**4**	—	33	33
Contracts settled	**(90)**	**(42)**	**(132)**	(57)	(10)	(67)
Change in foreign exchange rates	**67**	**5**	**72**	(50)	(2)	(52)
Transfers into (out of) Level III	**—**	**(4)**	**(4)**	—	1	1
Net risk management assets at end of period	**689**	**6**	**695**	719	52	771
Additional Level III information:						
Gains recognized in other comprehensive income	**60**	**—**	**60**	50	—	50
Total gains included in earnings before income taxes	**90**	**—**	**90**	57	29	86
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(42)**	**(42)**	—	19	19

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net liability fair value of $2 million as at Dec. 31, 2018 (Dec. 31, 2017 - $34 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2018, are primarily attributable to the settlement of contracts.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value(1)				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value(1)**
Long-term debt - Dec. 31, 2018	**—**	**3,181**	**—**	**3,181**	**3,204**
Long-term debt - Dec. 31, 2017	—	3,708	—	3,708	3,638

(1) Includes current portion.

The fair values of the Corporation's debentures and senior notes are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 20) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	**2018**	2017	2016
Unamortized net gain at beginning of year	**105**	148	202
New inception gains (losses)	**(14)**	12	10
Change in foreign exchange rates	**5**	(7)	(4)
Amortization recorded in net earnings during the year	**(47)**	(48)	(60)
Unamortized net gain at end of year	**49**	105	148

15. Risk Management Activities

A. Risk Management Strategy

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: i) financial exposure management and ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges, and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2018

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	59	–	59
Long-term	628	(8)	620
Net commodity risk management assets	687	(8)	679
Other			
Current	–	(3)	(3)
Long-term	–	1	1
Net other risk management assets (liabilities)	–	(2)	(2)
Total net risk management assets (liabilities)	687	(10)	677

As at Dec. 31, 2017

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	74	7	81
Long-term	636	11	647
Net commodity risk management assets	710	18	728
Other			
Current	–	37	37
Long-term	–	(3)	(3)
Net other risk management assets (liabilities)	–	34	34
Total net risk management assets (liabilities)	710	52	762

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	2018				2017			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**210**	**666**	**(121)**	**(50)**	281	637	(159)	(38)
Gross amounts set-off	**—**	**—**	**—**	**—**	(43)	—	43	—
Net amounts as presented in the Consolidated Statements of Financial Position	**210**	**666**	**(121)**	**(50)**	238	637	(116)	(38)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Corporation uses three tools:

- a framework of risk controls;
- a pre-defined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- a committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Corporation has executed commodity price hedges for its Centralia coal plant and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Corporation's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Corporation's exposure to market risks or the manner in which these risks are managed or measured.

i. Commodity Price Risk Management – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2018, associated with the Corporation's proprietary trading activities was $2 million (2017 - $5 million, 2016 - $2 million).

ii. Commodity Price Risk - Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2018, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $18 million (2017 - $16 million, 2016 - $19 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2018, associated with these transactions was $13 million (2017 - $5 million, 2016 - $7 million).

iii. Commodity Price Risk Management - Hedges

The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2018**		2017	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**2,128**	**—**	1,997	44

During 2018, unrealized pre-tax gains of $4 million (2017 - $2 million, 2016 - $0 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management - Non-Hedges

The Corporation's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	**2018**		2017	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**58,885**	**37,023**	14,688	7,348
Natural gas *(GJ)*	**80,413**	**110,488**	74,195	103,805
Transmission *(MWh)*	**29**	**11,163**	1	3,455
Emissions *(tonnes)*	**3,134**	**2,948**	516	717

b. Interest Rate Risk Management

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the Alberta coal PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represents 14 per cent of the Corporation's debt as at Dec. 31, 2018 (2017 - 6 per cent).

Interest rate risk is managed with the use of derivatives. No derivatives related to interest rate risk were outstanding as at Dec. 31, 2018, 2017 or 2016.

c. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar, the Japanese yen and the Australian dollar ("AUD"), as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Corporation may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies.
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

i. Net Investment Hedges
When designating foreign currency debt as a hedge of the Corporation's net investment in foreign subsidiaries, the Corporation has determined that the hedge is effective as the foreign currency of the net investment is the same as the currency of the hedge, and therefore an economic relationship is present.

The Corporation's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$400 million (2017 - US$480 million). During 2016, the Corporation de-designated its foreign currency forward contracts from its net investment hedges. The cumulative unrealized losses on these contracts are deferred in AOCI until the disposal of the related foreign operation.

ii. Cash Flow Hedges
The Corporation had no significant foreign currency cash flow hedges outstanding at Dec. 31, 2018 or 2017.

iii. Non-Hedges
As part of the sale of the economic interest in Australian Assets to TransAlta Renewables, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in the USD and AUD in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program.

The Corporation also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31		**2018**			2017	
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts - foreign-denominated receipts/expenditures						
AUD218	**CAD205**	**(5)**	**2019-2022**	CAD157	(9)	2018-2021
USD164	**CAD214**	**(7)**	**2019-2022**	CAD104	11	2018-2021
Foreign exchange forward contracts - foreign-denominated debt						
CAD124	**USD100**	**10**	**2022**	USD230	(4)	2018
Cross currency swaps - foreign-denominated debt						
—	—	—		USD270	35	2018

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. Changes in the risk management assets and liabilities related to these discontinued hedge positions have been reflected within net earnings prospectively.

iv. Impacts of currency rate risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2017 and 2016 - four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2018**		2017		2016	
Currency	**Net earnings increase (decrease)[1]**	**OCI gain[1],[2]**	Net earnings increase[1]	OCI gain[1],[2]	Net earnings decrease[1]	OCI gain[1],[2]
USD	**(13)**	**—**	(5)	—	(5)	—
AUD	**(7)**	**—**	(7)	—	(7)	—
Total	**(20)**	**—**	(12)	—	(12)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2018:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	86	14	**100**	**731**
Long-term finance lease receivables	100	—	**100**	**191**
Risk management assets[1]	99	1	**100**	**808**
Loans and notes receivable[2]	—	100	**100**	**77**
Total				**1,807**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes the promissory note receivable for $25 million (see Note 13), the loan receivable of $37 million and the note receivable for $15 million (see Note 20). The counterparties have no external credit ratings.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on historical rates of default by segment of trade receivables as well as forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2018.

The Corporation's maximum exposure to credit risk at Dec. 31, 2018, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2018, was $13 million (2017 - $40 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. As at Dec. 31, 2018, TransAlta maintains investment grade ratings from three credit rating agencies. TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

Counterparties enter into certain commodity agreements, such as electricity and natural gas purchase and sale contracts, for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these agreements may contain credit-contingent features (such as downgrades in creditworthiness), which if triggered may result in the Corporation having to post collateral to its counterparties.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Board; maintaining investment grade credit ratings; and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Corporation does not use derivatives or hedge accounting to manage liquidity risk.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Accounts payable and accrued liabilities	497	—	—	—	—	—	497
Long-term debt(1)	130	486	91	947	141	1,439	3,234
Commodity risk management assets	58	89	137	125	113	157	679
Other risk management (assets) liabilities	(3)	(3)	(3)	7	—	—	(2)
Finance lease obligations	18	16	9	5	5	10	63
Interest on long-term debt and finance lease obligations(2)	161	152	129	123	84	694	1,343
Dividends payable	58	—	—	—	—	—	58
Total	**919**	**740**	**363**	**1,207**	**343**	**2,300**	**5,872**

(1) Excludes impact of hedge accounting.
(2) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. Total Return Swaps

The Corporation has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

D. Hedging Instruments - Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2019	2020	2021	2022	2023	2024 and thereafter
Cash flow hedges						
Commodity Derivative Instruments						
Electricity						
Notional amount (thousands MWh)	3,950	3,465	3,424	3,329	3,329	5,966
Average Price ($ per MWh)	66.86	70.75	74.16	76.81	78.74	81.59

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is, as follows:

As at Dec. 31, 2018

	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	23 MMWh	687	Risk management assets	**60**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD400	CAD546	Credit facilities, long-term debt and finance lease obligations	**41**

The impact of the hedged items on the statement of financial position is, as follows:

As at Dec. 31, 2018

	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve
Commodity price risk		
Cash flow hedges		
Power forecast sales - Centralia	**60**	**508**

	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve
Net investment hedges		
Net investment in foreign subsidiaries	**41**	**84**

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness. There is no ineffectiveness recognized in profit or loss.

The impact of hedged items designated in hedging relationships on OCI and net earnings is:

Year ended Dec. 31, 2018					
		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**(9)**	Revenue	**(67)**	Revenue	**–**
		Fuel and purchased power	**–**	Fuel and purchased power	**–**
Foreign exchange forwards on commodity contracts	**–**	Revenue	**–**	Revenue	**–**
Foreign exchange forwards on project hedges	**–**	Property, plant and equipment	**–**	Foreign exchange (gain) loss	**–**
Foreign exchange forwards on US debt	**–**	Foreign exchange (gain) loss	**3**	Foreign exchange (gain) loss	**–**
Cross-currency swaps	**–**	Foreign exchange (gain) loss	**–**	Foreign exchange (gain) loss	**–**
Forward starting interest rate swaps	**–**	Interest expense	**7**	Interest expense	**–**
OCI impact	**(9)**	**OCI impact**	**(57)**	**Net earnings impact**	**–**

Over the next 12 months, the Corporation estimates that approximately $68 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2017 (as reported under IAS 39)					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	163	Revenue	(172)	Revenue	–
		Fuel and purchased power	–	Fuel and purchased power	–
Foreign exchange forwards on commodity contracts	–	Revenue	–	Revenue	–
Foreign exchange forwards on project hedges	(1)	Property, plant and equipment	–	Foreign exchange (gain) loss	–
Foreign exchange forwards on US debt	–	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	–
Cross-currency swaps	(26)	Foreign exchange (gain) loss	24	Foreign exchange (gain) loss	–
Forward starting interest rate swaps	–	Interest expense	7	Interest expense	–
OCI impact	136	OCI impact	(138)	Net earnings impact	–

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminates the generation effective Jan. 1, 2017. Accordingly, in 2017 the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 9(C) for further details.

Year ended Dec. 31, 2016 (as reported under IAS 39)

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	304	Revenue	(169)	Revenue	—
		Fuel and purchased power	44	Fuel and purchased power	31
Foreign exchange forwards on commodity contracts	(5)	Revenue	(16)	Revenue	(15)
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	(2)	Foreign exchange (gain) loss	53	Foreign exchange (gain) loss	—
Cross-currency swaps	(25)	Foreign exchange (gain) loss	(23)	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	271	OCI impact	(105)	Net earnings impact	16

II. Effect of Non-Hedges

For the year ended Dec. 31, 2018, the Corporation recognized a net unrealized loss of $29 million (2017 - gain of $45 million, 2016 - loss of $63 million) related to commodity derivatives.

For the year ended Dec. 31, 2018, a gain of $3 million (2017 - gain of $28 million, 2016 - gain of $9 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized gains of $4 million (2017 - losses of $2 million, 2016 - gains of $4 million) and net realized losses of $1 million (2017 - gains of $30 million, 2016 - gains of $5 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2018, the Corporation provided $105 million (2017 - $67 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2018, the Corporation held $17 million (2017 - $21 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2018, the Corporation had posted collateral of $120 million (Dec. 31, 2017 - $131 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $120 million (Dec. 31, 2017 - $96 million) of collateral to its counterparties.

16. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2018	2017
Parts and materials	**113**	118
Coal	**108**	58
Deferred stripping costs	**7**	11
Natural gas	**4**	9
Purchased emission credits	**10**	23
Total	**242**	219

The change in inventory is as follows:

Balance, Dec. 31, 2016	213
Net addition	11
Change in foreign exchange rates	(5)
Balance, Dec. 31, 2017	219
Net addition	**20**
Change in foreign exchange rates	**3**
Balance, Dec. 31, 2018	**242**

No inventory is pledged as security for liabilities.

17. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2016	95	5,876	1,525	3,212	1,265	407	393	12,773
Additions	—	—	—	—	—	334	4	338
Additions - finance lease	—	—	—	—	14	—	—	14
Disposals	—	—	(16)	(1)	(1)	—	(1)	(19)
Impairment charge - Sundance Unit 1 (Note 4)	—	(20)	—	—	—	—	—	(20)
Revisions and additions to decommissioning and restoration costs	—	82	12	15	42	—	—	151
Retirement of assets	—	(84)	(3)	(4)	(22)	—	(6)	(119)
Change in foreign exchange rates	(1)	(87)	3	(23)	(7)	(2)	(2)	(119)
Transfers[2][3]	1	121	461	29	24	(644)	(18)	(26)
As at Dec. 31, 2017	95	5,888	1,982	3,228	1,315	95	370	12,973
Additions[4]	**—**	**—**	**—**	**1**	**—**	**275**	**8**	**284**
Additions - finance lease	**—**	**—**	**—**	**—**	**10**	**—**	**—**	**10**
Disposals	**(3)**	**—**	**—**	**—**	**(1)**	**—**	**(3)**	**(7)**
Impairment charges (Note 7)	**—**	**(38)**	**—**	**(11)**	**—**	**—**	**—**	**(49)**
Revisions and additions to decommissioning and restoration costs	**—**	**(12)**	**(1)**	**(3)**	**(16)**	**—**	**—**	**(32)**
Retirement of assets	**—**	**(47)**	**(17)**	**(6)**	**(16)**	**—**	**(4)**	**(90)**
Change in foreign exchange rates	**2**	**105**	**(13)**	**26**	**7**	**4**	**—**	**131**
Transfers	**—**	**41**	**13**	**51**	**39**	**(174)**	**12**	**(18)**
As at Dec. 31, 2018	**94**	**5,937**	**1,964**	**3,286**	**1,338**	**200**	**383**	**13,202**
Accumulated depreciation								
As at Dec. 31, 2016	—	3,212	1,027	922	659	—	129	5,949
Depreciation	—	351	67	123	76	—	18	635
Retirement of assets	—	(62)	(2)	(3)	(18)	—	(5)	(90)
Disposals	—	—	(11)	(1)	—	—	—	(12)
Change in foreign exchange rates	—	(67)	(1)	(4)	(4)	—	—	(76)
Transfers[2]	—	(3)	(8)	—	—	—	—	(11)
As at Dec. 31, 2017	—	3,431	1,072	1,037	713	—	142	6,395
Depreciation	**—**	**306**	**79**	**123**	**125**	**—**	**16**	**649**
Retirement of assets	**—**	**(56)**	**(13)**	**(2)**	**(12)**	**—**	**—**	**(83)**
Disposals	**—**	**—**	**—**	**—**	**(1)**	**—**	**(4)**	**(5)**
Change in foreign exchange rates	**—**	**84**	**(3)**	**6**	**5**	**—**	**—**	**92**
Transfers	**—**	**—**	**(7)**	**(3)**	**—**	**—**	**—**	**(10)**
As at Dec. 31, 2018	**—**	**3,765**	**1,128**	**1,161**	**830**	**—**	**154**	**7,038**
Carrying amount								
As at Dec. 31, 2016	95	2,664	498	2,290	606	407	264	6,824
As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
As at Dec. 31, 2018	**94**	**2,172**	**836**	**2,125**	**508**	**200**	**229**	**6,164**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance, and the Australian gas pipeline.
(2) In 2017, net transfers of $14 million relate to the transfer of gas equipment to finance lease receivables.
(3) During the second quarter of 2017, the Corporation reclassified approximately $13 million of capital spares and other assets to inventory.
(4) Includes $7 million related to the acquisition of Big Level.

The Corporation capitalized $2 million of interest to PP&E in 2018 (2017 - $9 million) at a weighted average rate of 4.454 per cent (2017 – 5.87 per cent). Finance lease additions in 2018 and 2017 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2018, was $65 million (2017 - $65 million).

18. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	2018	2017
Hydro	**259**	259
Wind and Solar	**175**	174
Energy Marketing	**30**	30
Total goodwill	**464**	463

For the purposes of the 2018 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. In 2018, the Corporation relied on the recoverable amounts determined in 2016 for the Hydro and Energy Marketing segments in performing the 2018 annual goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2018 models ranged between $6 to $179 per MWh during the forecast period (2017 - $22 to $218 per MWh). Discount rates used for the goodwill impairment calculation in 2018 ranged from 5.3 per cent to 6.2 per cent (2017 – 5.5 per cent to 6.0 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2016	178	268	223	24	693
Additions	—	31	—	20	51
Change in foreign exchange rates	—	(3)	—	—	(3)
Transfers	—	18	—	(15)	3
As at Dec. 31, 2017	178	314	223	29	744
Additions(1)	**—**	**—**	**—**	**53**	**53**
Retirements and disposals(2)	**—**	**(2)**	**—**	**—**	**(2)**
Change in foreign exchange rates	**—**	**3**	**—**	**—**	**3**
Transfers	**7**	**24**	**14**	**(36)**	**9**
As at Dec. 31, 2018	**185**	**339**	**237**	**46**	**807**
Accumulated amortization					
As at Dec. 31, 2016	115	163	60	—	338
Amortization	8	24	9	—	41
Change in foreign exchange rates	—	1	—	—	1
Transfers	2	—	(2)	—	—
As at Dec. 31, 2017	125	188	67	—	380
Amortization	**9**	**32**	**9**	**—**	**50**
Retirements and disposals	**—**	**(1)**	**—**	**—**	**(1)**
Change in foreign exchange rates	**—**	**2**	**—**	**—**	**2**
Transfers	**(17)**	**—**	**20**	**—**	**3**
As at Dec. 31, 2018	**117**	**221**	**96**	**—**	**434**
Carrying amount					
As at Dec. 31, 2016	63	105	163	24	355
As at Dec. 31, 2017	53	126	156	29	364
As at Dec. 31, 2018	**68**	**118**	**141**	**46**	**373**

(1) Includes $33 million related to the acquisition of Big Level.
(2) Includes the impairment charge of $1 million relating to Kent Breeze. See Note 7 for further details.

20. Other Assets

The components of other assets are as follows:

As at Dec. 31	2018	2017
South Hedland prepaid transmission access and distribution costs	**72**	75
Deferred licence fees	**11**	13
Project development costs	**47**	53
Deferred service costs	**12**	15
Long-term prepaids and other assets	**53**	44
Loan receivable	**37**	33
Keephills Unit 3 transmission deposit	**2**	4
Total other assets	**234**	237

South Hedland prepaid electricity transmission and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Project development costs are primarily comprised of the Corporation's Sundance 7 project in Alberta and project costs for the Pioneer Pipeline project (Note 4(A)). In December 2015, the Corporation repurchased its partner's 50 per cent share in TAMA Power, the jointly controlled entity developing the Sundance 7 project, for consideration of $10 million, payable in four years and an option for its partner to re-enter the development projects of TAMA Power at accumulated cost during this period. Some projects were written off in 2018 as they are no longer proceeding (see Note 7(B)).

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 33.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $37 million (2017 - $38 million) (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022. The current portion of nil (2017 - $5 million) is included in accounts receivable and the long-term portion of the $37 million (2017 - $33 million) is included in other assets.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next four years to 2021, as long as certain performance criteria are met.

21. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2016	293	50	343
Liabilities incurred	3	19	22
Liabilities settled	(19)	(31)	(50)
Liabilities disposed[1]	(8)	—	(8)
Accretion	23	—	23
Revisions in estimated cash flows[2]	41	1	42
Revisions in discount rates[2]	110	—	110
Reversals	—	(4)	(4)
Change in foreign exchange rates	(6)	(2)	(8)
Balance, Dec. 31, 2017	437	33	470
Liabilities incurred	**5**	**17**	**22**
Liabilities settled	**(31)**	**(10)**	**(41)**
Accretion	**24**	**—**	**24**
Acquisition of liabilities (Big Level)		**8**	**8**
Revisions in estimated cash flows	**2**	**3**	**5**
Revisions in discount rates	**(37)**	**—**	**(37)**
Reversals	**—**	**(5)**	**(5)**
Change in foreign exchange rates	**7**	**3**	**10**
Balance, Dec. 31, 2018	**407**	**49**	**456**

(1) Relates to the disposition of the Solomon power station and the sale of the Wintering Hills wind facility.
(2) During 2017, mainly as a result of the OCA (see Note 4(O)), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to the use of 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2017	437	33	470
Current portion	40	27	67
Non-current portion	397	6	403
Balance, Dec. 31, 2018	**407**	**49**	**456**
Current portion	**35**	**35**	**70**
Non-current portion	**372**	**14**	**386**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1 billion, which will be incurred between 2019 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2018, the Corporation had provided a surety bond in the amount of US$139 million (2017 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2018, the Corporation had provided letters of credit in the amount of $122 million (2017 - $120 million) in support of future decommissioning obligations at the Alberta mine. 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.

B. Other Provisions

Other provisions include amounts related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used and for vacant leased premises.

Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2023.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

22. Credit Facilities, Long-Term Debt and Finance Lease Obligations

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31		**2018**			2017	
	Carrying value	**Face value**	**Interest**[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**339**	**339**	**3.8%**	27	27	2.8%
Debentures	**647**	**651**	**5.8%**	1,046	1,051	6.0%
Senior notes[3]	**943**	**955**	**5.4%**	1,499	1,510	6.0%
Non-recourse[4]	**1,236**	**1,250**	**4.4%**	1,022	1,032	4.3%
Other[5]	**39**	**39**	**9.2%**	44	44	9.2%
	3,204	**3,234**		3,638	3,664	
Finance lease obligations	**63**			69		
	3,267			3,707		
Less: current portion of long-term debt	**(130)**			(729)		
Less: current portion of finance lease obligations	**(18)**			(18)		
Total current long-term debt and finance lease obligations	**(148)**			(747)		
Total credit facilities, long-term debt and finance lease obligations	**3,119**			2,960		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2018 - US$0.7 billion (Dec. 31, 2017 - US$1.2 billion).
(4) Includes US$1 million at Dec. 31, 2018 (Dec. 31, 2017 - US$27 million).
(5) Includes US$21 million at Dec. 31, 2018 (Dec. 31, 2017 - US$24 million) of tax equity financing.

Credit facilities are comprised of the Corporation's $1.25 billion committed syndicated bank credit facility expiring in 2022, TransAlta Renewable's $500 million committed syndicated bank credit facility expiring in 2022 and the Corporation's three bilateral credit facilities totalling $240 million expiring in 2020. The $1.75 billion (Dec. 31, 2017 - $1.5 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate - in accordance with a pricing grid that is standard for such facilities.

During 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

During 2017:

- TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The agreement is fully committed for four years. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate - in accordance with a pricing grid that is standard for such facilities. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the credit agreement, the $350 million credit facility provided by TransAlta was cancelled.

The Corporation has a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $0.5 billion (Dec. 31, 2017 - $0.5 billion). In total, $0.9 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At Dec. 31, 2018, the $1.1 billion (Dec. 31, 2017 - $627 million) of credit utilized under these facilities was comprised of actual drawings of $339 million (Dec. 31, 2017 - $27 million) and letters of credit of $720 million (Dec. 31, 2017 - $677 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $0.9 billion available under the credit facilities, the Corporation also has $89 million of available cash and cash equivalents and $35 million ($27 million principal portion) in cash restricted for repayment of the OCP bonds (see section E below).

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030.

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040.

During 2018, the Corporation early redeemed its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

During 2017, the Corporation's US$400 million 1.90 per cent senior note matured and was paid out using existing liquidity. The repayment was hedged with a currency swap. The maturity value of the bond was $434 million.

A total of US$400 million (2017 - US$480 million) of the senior notes has been designated as a hedge of the Corporation’s net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 6.26 per cent.

During 2018, the Corporation:
- Paid out the US$25 million non-recourse debt related to its Mass Solar projects.
- Monetized the OCA and closed a $345 million bond offering through its indirect wholly owned subsidiary TransAlta OCP by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

During 2017, TransAlta Renewables closed a $260 million non-recourse bond offering by way of a private placement. At the same time, the Corporation early redeemed the $191 million face value CHD non-recourse debentures on Oct. 12, 2017. The redemption price was $201 million, including an early redemption premium of $6 million, recognized in net interest expense and accrued and unpaid interest of $4 million.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financing assumed in the Lakeswind wind acquisition.

TransAlta’s debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2018, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and OCP non-recourse bonds with a carrying value of $1,235 million (Dec. 31, 2017 - $1,022 million) are subject to customary financing conditions and covenants that may restrict the Corporation’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2019. At Dec. 31, 2018, $33 million (Dec. 31, 2017 -$35 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2018.

C. Security

Non-recourse debts of $766 million in total (Dec. 31, 2017 - $848 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of $1,021 million at Dec. 31, 2018 (Dec. 31, 2017 - $1,107 million). At Dec. 31, 2018, a non-recourse bond of approximately $127 million (Dec. 31, 2017 - $174 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The new TransAlta OCP bonds with a carrying value of $342 million are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

D. Principal Repayments

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Principal repayments[(1)]	130	486	91	947	141	1,439	3,234

(1) Excludes impact of derivatives.

E. Restricted Cash

The Corporation has $31 million (Dec. 31, 2017 - $30 million) of restricted cash related to the Kent Hills project financing that is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in Q1 2019.

The Corporation also has $35 million (Dec. 31, 2017 - nil) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2019.

F. Finance Lease Obligations

Amounts payable for mining assets and other finance leases are as follows:

As at Dec. 31	**2018**		2017	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**21**	**20**	20	20
Second to fifth years inclusive	**39**	**35**	43	38
More than five years	**10**	**8**	15	11
	70	**63**	78	69
Less: interest costs	**7**	**—**	9	—
Total finance lease obligations	**63**	**63**	69	69

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease obligations	**18**	18
Long-term portion of finance lease obligations	**45**	51
	63	69

G. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities and its uncommitted $100 million demand letter of credit facility. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $100 million demand letter of credit facility.

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2018, was $720 million (2017 - $677 million) with no (2017 - nil) amounts exercised by third parties under these arrangements.

23. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2018	2017
Defined benefit obligation (Note 28)	**227**	235
Long-term incentive accruals (Note 27)	**9**	16
Other	**51**	46
Total[1]	**287**	297

(1) 2017 deferred revenues of $62 million have been reclassified on the statement of financial position to contract liabilities as required under IFRS 15. See Note 3(A) and Note 5(B) for further details.

24. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

As at Dec. 31	2018		2017	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**287.9**	**3,094**	287.9	3,095
Purchased and cancelled under the NCIB	**(3.3)**	**(35)**	—	—
	284.6	**3,059**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**—**	—	(1)
Issued and outstanding, end of year	**284.6**	**3,059**	287.9	3,094

B. NCIB Program

Shares purchased by the Corporation under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year ended Dec. 31, 2018:

Total shares purchased[1]		**3,264,500**
Average purchase price per share	**$**	**7.02**
Total cost		**23**
Weighted average book value of shares cancelled		**35**
Increase to retained earnings		**12**

(1) Includes 204,000 shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 22, 2016. The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. When an acquiring shareholder acquires 20 per cent or more of the Corporation's common shares, other than by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

D. Earnings per Share

Year ended Dec. 31	2018	2017	2016
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Basic and diluted weighted average number of common shares outstanding (millions)	**287**	288	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.86)**	(0.66)	0.41

E. Dividends

On Oct. 10, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2019.

On Dec. 14, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Apr. 1, 2019.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

25. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	2018		2017	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Sept. 17, 2017, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017, to, but excluding, Sept. 30, 2022, will be 5.194 per cent, which is equal to the five-year Government of Canada bond yield of 1.544 per cent, determined as of Aug. 31, 2017, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

II. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 16, 2017, the Corporation announced that after, taking into account all election notices received by the June 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C

Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017, to, but excluding, June 30, 2022, will be 4.027 per cent, which is equal to the five-year Government of Canada bond yield of 0.927 per cent, determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

III. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion
On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2018.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on the 90 day Treasury Bill rate plus 2.03%.

IV. Preferred Share Series Information
The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, they are also:

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2018, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.67725	March 31, 2021	2.03	B
B	Floating	0.93575	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29850	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.32500	Sept. 30, 2019	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the preferred share dividends declared in 2018, 2017 and 2016:

	Total dividends declared ($)		
Series	**2018**	2017	2016
A	**9**	5	10
B	**1**	1	1
C	**14**	9	16
E	**15**	8	14
G	**11**	7	11
Total for the year	**50**	30	52

26. Accumulated Other Comprehensive Income

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2018	2017
Currency translation adjustment		
Opening balance, Jan. 1	**(26)**	(1)
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax(1)	**84**	(89)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(2)	**(41)**	64
Balance, Dec. 31	**17**	(26)
Cash flow hedges		
Opening balance, Jan. 1	**562**	456
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(3)	**(54)**	106
Balance, Dec. 31	**508**	562
Employee future benefits		
Opening balance, Jan. 1	**(44)**	(38)
Net actuarial gains (losses) on defined benefit plans, net of tax(4)	**15**	(6)
Balance, Dec. 31	**(29)**	(44)
Other		
Opening balance, Jan. 1	**(3)**	(18)
Change in ownership of TransAlta Renewables	**4**	4
Intercompany investments at FVOCI	**(16)**	11
Balance, Dec. 31	**(15)**	(3)
Accumulated other comprehensive income	**481**	489

(1) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 11 million).
(2) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 4 million).
(3) Net of income tax of 12 million for the year ended Dec. 31, 2018 (2017 - 108 million).
(4) Net of income tax of 5 million for the year ended Dec. 31, 2018 (2017 - 4 million).

27. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued at the end of each reporting period using the closing price of the Corporation's common shares on the TSX.

The pre-tax compensation expense related to PSUs and RSUs in 2018 was $8 million (2017 - $15 million , 2016 - $17 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was nil in 2018 (2017 - $1 million, 2016 - $3 million).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In February 2018, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.45 that vest after a three-year period and expire seven years after issuance. In March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance. In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance. The expense recognized relating to these grants during 2018 was approximately $1 million (2017 - approximately $1 million, 2016 - less than $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2018, are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 8.00	2.3	5	6.71
22.00 - 30.00[1]	0.5	1.1	23.69
5.00 - 30.00	**2.8**	**4.3**	**9.66**

(1) Options currently exercisable.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation extended interest-free loans (up to 30 per cent of an employee's base salary) to employees below executive level and allowed for payroll deductions over a three-year period to repay the loan. Executives were not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchased these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares were handled in the same manner. At Dec. 31, 2018, amounts receivable from employees under the plan was nil (2017 - less than $1 million).

On Jan. 14, 2016, the Corporation suspended its employee share purchase plan.

28. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the US covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec .31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2018. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2018.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the US. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation posted a letter of credit in March 2018 for the amount of $80 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2018, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2018.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 401 (k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2018	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**9**	**2**	**1**	**12**
Administration expenses	**1**	**–**	**–**	**1**
Interest cost on defined benefit obligation	**18**	**3**	**1**	**22**
Interest on plan assets	**(13)**	**–**	**–**	**(13)**
Defined benefit expense	**15**	**5**	**2**	**22**
Defined contribution expense	**10**	**–**	**–**	**10**
Net expense	**25**	**5**	**2**	**32**

Year ended Dec. 31, 2017	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	20	3	1	24
Interest on plan assets	(15)	–	–	(15)
Defined benefit expense	14	5	2	21
Defined contribution expense	11	–	–	11
Net expense	25	5	2	32

Year ended Dec. 31, 2016	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	–	–	(16)
Defined benefit expense	14	5	3	22
Defined contribution expense	15	–	–	15
Net expense	29	5	3	37

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2018	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**368**	**13**	**–**	**381**
Present value of defined benefit obligation	**(514)**	**(80)**	**(25)**	**(619)**
Funded status - plan deficit	**(146)**	**(67)**	**(25)**	**(238)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(5)**	**(5)**	**(1)**	**(11)**
Other long-term liabilities	**(141)**	**(62)**	**(24)**	**(227)**
Total amount recognized	**(146)**	**(67)**	**(25)**	**(238)**

As at Dec. 31, 2017	Registered	Supplemental	Other	Total
Fair value of plan assets	416	12	–	428
Present value of defined benefit obligation	(561)	(87)	(27)	(675)
Funded status - plan deficit	(145)	(75)	(27)	(247)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(4)	(6)	(2)	(12)
Other long-term liabilities	(141)	(69)	(25)	(235)
Total amount recognized	(145)	(75)	(27)	(247)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
As at Dec. 31, 2016	423	10	–	433
Interest on plan assets	15	–	–	15
Net return on plan assets	26	–	–	26
Contributions	6	6	–	12
Benefits paid	(51)	(4)	–	(55)
Administration expenses	(2)	–	–	(2)
Effect of translation on US plans	(1)	–	–	(1)
As at Dec. 31, 2017	416	12	–	428
Interest on plan assets	**13**	**–**	**–**	**13**
Net return on plan assets	**(25)**	**–**	**–**	**(25)**
Contributions	**5**	**6**	**1**	**12**
Benefits paid	**(42)**	**(5)**	**(1)**	**(48)**
Administration expenses	**(1)**	**–**	**–**	**(1)**
Effect of translation on US plans	**2**	**–**	**–**	**2**
As at Dec. 31, 2018	**368**	**13**	**–**	**381**

The fair value of the Corporation's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2018	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**65**	**—**	**65**
US	**—**	**26**	**—**	**26**
International	**—**	**101**	**—**	**101**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**48**	**—**	**48**
AA	**—**	**64**	**—**	**64**
A	**—**	**39**	**—**	**39**
BBB	**1**	**21**	**—**	**22**
Below BBB	**—**	**3**	**—**	**3**
Money market and cash and cash equivalents	**(2)**	**14**	**—**	**12**
Total	**(1)**	**381**	**1**	**381**

Year ended Dec. 31, 2017	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	76	—	76
US	—	31	—	31
International	—	118	—	118
Private	—	—	1	1
Bonds				
AAA	—	43	—	43
AA	—	71	—	71
A	—	44	—	44
BBB	1	25	—	26
Below BBB	—	5	—	5
Money market and cash and cash equivalents	(1)	14	—	13
Total	—	427	1	428

Plan assets do not include any common shares of the Corporation at Dec. 31, 2018, and Dec. 31, 2017. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2018 (2017 - $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2016	554	82	27	663
Current service cost	7	2	1	10
Interest cost	20	3	1	24
Benefits paid	(51)	(4)	—	(55)
Actuarial gain arising from demographic assumptions	4	1	—	5
Actuarial loss arising from financial assumptions	26	3	—	29
Actuarial gain (loss) arising from experience adjustments	3	—	(1)	2
Effect of translation on US plans	(2)	—	(1)	(3)
Present value of defined benefit obligation as at Dec. 31, 2017	**561**	**87**	**27**	**675**
Current service cost	**9**	**2**	**1**	**12**
Interest cost	**18**	**3**	**1**	**22**
Benefits paid	**(42)**	**(5)**	**(1)**	**(48)**
Actuarial (gain) loss arising from financial assumptions	**(35)**	**(7)**	**(2)**	**(44)**
Actuarial (gain) loss arising from experience adjustments	**—**	**—**	**(1)**	**(1)**
Effect of translation on US plans	**3**	**—**	**—**	**3**
Present value of defined benefit obligation as at Dec. 31, 2018	**514**	**80**	**25**	**619**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2018 is 14 years.

F. Contributions

The expected employer contributions for 2019 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**4**	**2**	**11**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2018			As at Dec. 31, 2017		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.9**	**3.8**	**3.9**	3.3	3.3	3.4
Rate of compensation increase	**2.5**	**3.0**	**—**	2.9	3.0	—
Assumed health care cost trend rate						
Health care cost escalation(1)(3)	**—**	**—**	**7.1**	—	—	7.8
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.3**	**3.3**	**3.4**	3.7	3.6	3.7
Rate of compensation increase	**2.6**	**3.0**	**—**	2.6	3.0	—
Assumed health care cost trend rate						
Health care cost escalation(2)(4)	**—**	**—**	**7.6**	—	—	7.9
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health care premium escalation	**—**	**—**	**—**	—	—	—

(1) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(3) 2017 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(4) 2017 Post- and pre-65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 5% in 2024 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			**US plans**	
Year ended Dec. 31, 2018	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**70**	**11**	**3**	**2**	**1**
1% increase in the salary scale	**10**	**1**	**—**	**—**	**—**
1% increase in the health care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**18**	**3**	**—**	**1**	**—**

29. Joint Arrangements

Joint arrangements at Dec. 31, 2018, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

30. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2018	2017	2016
(Use) source:			
Accounts receivable	**58**	(228)	(23)
Prepaid expenses	**19**	(75)	5
Income taxes receivable	**—**	8	(4)
Inventory	**(21)**	(7)	11
Accounts payable, accrued liabilities, and provisions	**(97)**	186	81
Income taxes payable	**(3)**	2	3
Change in non-cash operating working capital	**(44)**	(114)	73

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2017	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2018
Long-term debt and finance lease obligations	3,707	(540)	10	—	95	(5)	3,267
Dividends payable (common and preferred)	34	(86)	—	107	—	3	58
Total liabilities from financing activities	**3,741**	**(626)**	**10**	**107**	**95**	**(2)**	**3,325**

	Balance Dec. 31, 2016	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2017
Long-term debt and finance lease obligations	4,361	(545)	14	—	(115)	(8)	3,707
Dividends payable (common and preferred)	54	(86)	—	64	—	2	34
Total liabilities from financing activities	4,415	(631)	14	64	(115)	(6)	3,741

31. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2018	2017	Increase/ (decrease)
Long-term debt[1]	**3,267**	3,707	**(440)**
Equity			
Common shares	**3,059**	3,094	**(35)**
Preferred shares	**942**	942	**—**
Contributed surplus	**11**	10	**1**
Deficit	**(1,496)**	(1,209)	**(287)**
Accumulated other comprehensive income	**481**	489	**(8)**
Non-controlling interests	**1,137**	1,059	**78**
Less: available cash and cash equivalents[2]	**(89)**	(314)	**225**
Less: principal portion of restricted cash on OCP Bonds[3]	**(27)**	—	**(27)**
Less: fair value asset of hedging instruments on long-term debt[4]	**(10)**	(30)	**20**
Total capital	**7,275**	7,748	**(473)**

(1) Includes finance lease obligations, amounts outstanding under credit facilities, tax equity liability and current portion of long-term debt.
(2) The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available and used to facilitate repayment of debt.
(3) The Corporation includes the principal portion of restricted cash on OCP bonds because this cash is restricted specifically to repay outstanding debt.
(4) The Corporation includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

In 2018, the Corporation continued to focus on reducing overall debt. The Corporation's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2017, and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios and targets to manage the Corporation's 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.

The Corporation has an investment grade credit rating from Standard & Poor's (negative outlook), DBRS (stable outlook) and Fitch Ratings (stable outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook and in June 2018 Moody's revised their rating outlook to positive from stable. During 2018, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low), and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with negative outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing. Strengthening the Corporation's financial position allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles.

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 help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. These ratios are summarized in the table below:

As at Dec. 31	2018	2017	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.8**	4.3	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**20.8**	20.4	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation and amortization (times)	**3.7**	3.6	3.0 to 3.5

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO plus interest on debt (net of capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less 50 per cent of dividends paid on preferred shares divided by net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents and including fair value assets of hedging instruments on debt). The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is calculated as net debt divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2018, the Corporation continued to strengthen its financial position and reduce debt.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, Invest in PP&E and Make Acquisitions

For the years ended Dec. 31, 2018 and 2017, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2018	2017	Increase (decrease)
Cash flow from operating activities	**820**	626	194
Change in non-cash working capital	**44**	114	(70)
Cash flow from operations before changes in working capital	**864**	740	124
Dividends paid on common shares	**(46)**	(46)	—
Dividends paid on preferred shares	**(40)**	(40)	—
Distributions paid to subsidiaries' non-controlling interests	**(165)**	(172)	7
Property, plant and equipment expenditures(1)	**(277)**	(338)	61
Inflow	**336**	144	192

(1) Includes growth capital associated with the South Hedland Power Station.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2018, $0.9 billion (2017 - $1.4 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

32. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2018, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	60.9	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel
TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	2018	2017	2016
Total compensation	**17**	24	20
Comprised of:			
Short-term employee benefits	**11**	14	8
Post-employment benefits	**2**	2	2
Share-based payments	**4**	8	10

33. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Natural gas, transportation and other purchase contracts	28	15	13	11	12	157	**236**
Transmission	9	10	6	4	3	–	**32**
Coal supply and mining agreements	158	160	27	24	24	95	**488**
Long-term service agreements	64	86	32	17	8	34	**241**
Non-cancellable operating leases	8	8	8	7	4	45	**80**
Growth	324	79	144	–	–	–	**547**
TransAlta Energy Transition Bill	6	7	6	6	6	–	**31**
Total	**597**	**365**	**236**	**69**	**57**	**331**	**1,655**

A. Natural Gas, Transportation and Other Purchase Contracts
Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other purchase contracts relate to commitments for goods and services.

B. Transmission

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2020.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements. Some of these commitments have been reduced due to the cessation of coal-fired emissions from the Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities and turbines at various wind facilities.

E. Non-Cancellable Operating Leases

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

During the year ended Dec. 31, 2018, $8 million (2017 - $7 million, 2016 - $9 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2018, 2017 and 2016 were less than $1 million. No contingent rental payments were made in respect of these operating leases.

F. Growth

Commitments for growth relate to the Big Level, Antrim and Windrise wind development projects, the coal-to-gas conversions, and to the Corporation's 50% share of the Pioneer Pipeline project.

G. TransAlta Energy Transition Bill Commitments

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining nine-year life of the Centralia coal plant to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Dec. 31, 2018, the Corporation has funded approximately US$33 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA MWs. The current estimate of exposure based on known data is $15 million and therefore the Corporation increased the provision from $7.5 million to $15 million in 2018.

II. FMG Disputes
The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

III. Balancing Pool Dispute
Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018, as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

34. Segment Disclosures

A. Description of Reportable Segments
The Corporation has eight reportable segments as described in Note 1.

B. Reported Segment Earnings (Loss) and Segment Assets
I. Earnings Information

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	442	232	165	282	156	67	(7)	2,249
Fuel and purchased power	666	314	96	8	17	6	—	(7)	1,100
Gross margin	246	128	136	157	265	150	67	—	1,149
Operations, maintenance and administration	171	61	48	37	50	38	24	86	515
Depreciation and amortization	241	74	43	49	110	30	2	25	574
Asset impairment charge	38	—	—	—	12	—	—	23	73
Taxes, other than income taxes	13	5	1	—	8	3	—	1	31
Net other operating expense (income)	(198)	—	—	—	(6)	—	—	—	(204)
Operating income (loss)	(19)	(12)	44	71	91	79	41	(135)	160
Finance lease income	—	—	8	—	—	—	—	—	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets and other									1
Losses before income taxes									(96)

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	999	435	261	135	287	121	69	—	2,307
Fuel and purchased power	585	293	101	14	17	6	—	—	1,016
Gross margin	414	142	160	121	270	115	69	—	1,291
Operations, maintenance and administration	192	51	50	31	48	37	24	84	517
Depreciation and amortization	317	73	38	37	111	31	2	26	635
Asset impairment charge	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	13	4	1	—	8	3	—	1	30
Net other operating expense (income)	(40)	—	(9)	—	—	—	—	—	(49)
Operating income (loss)	(88)	14	80	53	103	44	43	(111)	138
Finance lease income	—	—	11	43	—	—	—	—	54
Net interest expense									(247)
Foreign exchange loss									(1)
Gain on sale of assets									2
Earnings before income taxes									(54)

Year ended Dec. 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	1,048	354	402	119	272	126	76	—	2,397
Fuel and purchased power	451	281	185	20	18	8	—	—	963
Gross margin	597	73	217	99	254	118	76	—	1,434
Operations, maintenance and administration	178	54	54	25	52	33	24	69	489
Depreciation and amortization	242	61	100	17	119	33	3	26	601
Asset impairment reversals	—	—	—	—	28	—	—	—	28
Taxes, other than income taxes	13	4	1	1	8	3	—	1	31
Net other operating expense (income)	(2)	—	(191)	—	(1)	—	—	1	(193)
Operating income (loss)	166	(46)	253	56	48	49	49	(97)	478
Finance lease income	—	—	14	52	—	—	—	—	66
Net interest expense									(229)
Foreign exchange loss									(5)
Gain on sale of assets									4
Earnings before income taxes									314

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2018 is $16 million (2017 -$18 million, 2016 - $19 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2018	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	—	—	—	—	**175**	**259**	**30**	—	**464**
PP&E	**2,587**	**332**	**391**	**554**	**1,799**	**481**	**1**	**19**	**6,164**
Intangible assets	**81**	**7**	**4**	**41**	**173**	**4**	**11**	**52**	**373**

As at Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	—	—	—	—	174	259	30	—	463
PP&E	2,902	370	416	606	1,764	497	1	22	6,578
Intangibles	91	7	3	42	149	3	13	56	364

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2018	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**101**	**14**	**21**	**6**	**117**	**16**	—	**2**	**277**
Intangible assets	**3**	—	—	—	—	—	—	**17**	**20**

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	116	35	31	114	20	16	—	6	338
Intangibles	5	1	—	29	—	—	—	16	51

Year ended Dec. 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	159	15	11	107	16	43	—	7	358
Intangibles	3	1	1	—	—	—	—	16	21

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	**2018**	2017	2016
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**574**	635	601
Depreciation included in fuel and purchased power (Note 6)	**136**	73	63
Depreciation and amortization on the Consolidated Statements of Cash Flows	**710**	708	664

C. Geographic Information
I. Revenues

Year ended Dec. 31	2018	2017	2016
Canada	**1,573**	1,663	1,828
US	**511**	509	450
Australia	**165**	135	119
Total revenue	**2,249**	2,307	2,397

II. Non-Current Assets

	Property, plant and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Canada	**4,953**	5,353	**273**	297	**101**	105	**417**	417
US	**657**	619	**59**	25	**50**	43	**47**	46
Australia	**554**	606	**41**	42	**83**	89	**—**	—
Total	**6,164**	6,578	**373**	364	**234**	237	**464**	463

D. Significant Customer
During the year ended Dec. 31, 2018, sales to one customer represented 19 per cent of the Corporation's total revenue (2017 - one customer represented 28 per cent).

Exhibit 1

(Unaudited)

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2018:

Earnings coverage on long-term debt supporting the Corporation’s Shelf Prospectus

0.23 times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2018	2017	2016
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,249**	2,307	2,397
Operating income	**160**	138	478
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
STATEMENT OF FINANCIAL POSITION			
Total assets	**9,428**	10,304	10,996
Current portion of long-term debt, net of cash and cash equivalents	**59**	433	334
Credit facilities, long-term debt and finance lease obligations	**3,119**	2,960	3,722
Non-controlling interests	**1,137**	1,059	1,152
Preferred shares	**942**	942	942
Equity attributable to common shareholders	**2,055**	2,384	2,569
Fair value (asset) liability of hedging instruments on debt	**(10)**	(30)	(163)
Total invested capital(2)	**7,275**	7,748	8,556
CASH FLOWS			
Cash flow from operating activities	**820**	626	744
Cash flow from (used in) investing activities	**(394)**	87	(327)
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**(0.86)**	(0.66)	0.41
Comparable earnings(1)	**n/a**	n/a	0.13
Dividends paid on common shares	**0.20**	0.16	0.30
Book value per common share (at year-end)	**7.16**	8.28	8.92
Market price:			
High	**7.9**	8.50	7.54
Low	**5.44**	6.88	3.76
Close (Toronto Stock Exchange at Dec. 31)	**5.59**	7.45	7.43
RATIOS (percentage except where noted)			
Adjusted net debt to invested capital	**49.7**	49.5	51
Adjusted net debt to invested capital excluding non-recourse debt	**39.4**	41.8	44.2
Adjusted net debt to comparable EBITDA(1)(5) (times)	**3.7**	3.6	3.8
Return on equity attributable to common shareholders	**(15.76)**	(10.00)	5.4
Comparable return on equity attributable to common shareholders(1)	**n/a**	n/a	1.7
Return on capital employed	**0.7**	2.1	5.3
Comparable return on capital employed(1)	**n/a**	n/a	4.4
Earnings coverage (times)	**0.2**	0.6	1.7
Dividend payout ratio based on comparable funds from operations(1)(5)	**6.1**	4.3	8.1
Comparable EBITDA(1)(5) (in millions of Canadian dollars)	**1,123**	1,062	1,144
Dividend coverage(1)(5) (times)	**18.3**	14.1	11.1
Dividend yield	**2.9**	2.1	4
Adjusted comparable funds from operations to adjusted net debt(1)(5)	**20.8**	20.4	16.3
FFO before interest to adjusted interest coverage(1)(5) (times)	**4.8**	4.3	3.9
Weighted average common shares for the year (in millions)	**287**	288	288
Common shares outstanding at Dec. 31 (in millions)	**285**	288	288
STATISTICAL SUMMARY			
Number of employees	**1,883**	2,228	2,341
Generating capacity (MW)(3)			
Coal (Canadian and US)	**4,571**	5,131	5,131
Gas(4)	**1,395**	1,403	1,482
Renewables (wind, solar and hydro)	**2,308**	2,289	2,334
Equity investments	**—**	—	—
Total generating capacity	**8,273**	8,823	8,947
Total generation production (GWh)	**28,409**	36,900	38,157

Financial data presented is based on IFRS. Financial data for 2009 and prior is based on Canadian GAAP. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

(1) Total invested capital for 2014 to 2009 has been revised to align with the 2015 calculation methodology.

(2) These ratios were calculated using non-IFRS measures. Periods for which the non-IFRS measure was not previously disclosed have not been calculated. For 2017, comparable earnings measures are no longer being calculated or reported on.

(3) 2017, 2016, 2015, 2014, 2013 and 2012 are gross capacity, which reflects the basis of underlying results. Prior year figures are as previously reported.

(4) Includes finance leases.

(5) 2016 and 2015 revised due to revisions to EBITDA or FFO measures in MD&A.

Ratio Formulas

Adjusted net debt to invested capital = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents / long-term debt and finance lease obligations including current portion + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares - cash and cash equivalents

Adjusted net debt to comparable EBITDA = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt - cash and cash equivalents + 50 per cent issued preferred shares / comparable EBITDA

Return on equity attributable to common shareholders = net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / equity attributable to common shareholders excluding Accumulated Other Comprehensive Income ("AOCI")

2015	2014	2013	2012	2011	2010	2009	2008
2,267	2,623	2,292	2,210	2,618	2,673	2,770	3,110
148	442	195	(214)	645	487	378	533
(24)	141	(71)	(615)	290	255	181	235
10,947	9,833	9,624	9,503	9,780	9,635	9,762	7,815
33	708	175	582	284	202	(51)	194
4,408	3,305	4,130	3,610	3,721	3,823	4,411	2,564
1,029	594	517	330	358	431	478	469
942	942	781	—	—	—	—	—
2,419	2,342	2,125	3,018	3,274	3,120	2,929	2,510
(190)	(96)	(16)	50	32	41	16	—
8,641	7,795	7,712	7,590	7,669	7,617	7,783	5,737
432	796	765	520	690	838	580	1,038
(573)	(292)	(703)	(1,048)	(608)	(765)	(1,598)	(581)
-0.09	0.52	-0.27	-2.62	1.31	1.16	0.9	1.18
-0.17	0.25	0.31	0.5	1.05	0.97	0.9	1.46
0.72	0.83	1.16	1.16	1.16	1.16	1.16	1.08
8.52	8.52	7.92	8.78	12.08	12.85	13.41	12.7
12.34	14.94	16.86	21.37	23.24	23.98	25.3	37.5
4.13	9.81	12.91	14.11	19.45	19.61	18.11	21
4.91	10.52	13.48	15.12	21.02	21.15	23.48	24.3
54.6	56.3	60.7	61	52.5	53.1	56.1	48.1
50.2	54.1	58.7	59	60	50.7	52.6	45.6
5.4	4.2	4.6	4.6	3.8	—	—	—
-1.2	6.3	-3.2	-25.9	10.6	9.6	6.9	9.4
-2.3	3	3.7	4.9	8.4	8	6.9	11.6
4.6	5.8	2.8	-3.1	8.3	6.6	5.7	7.7
3	5.1	5.2	5.3	7	6	5.8	9.6
1.5	1.7	0.8	(1.00)	2.7	2.2	1.9	2.8
30	26.4	43.1	25.1	24	40	—	—
867	1,036	1,023	1,015	1,044	955	888	1,006
3.3	5.7	6.3	4.7	3.5	4	2.6	4.8
14.7	7.9	8.6	7.7	5.5	5.5	4.9	4.4
14.3	16.9	15.2	16.7	20.1	19.6	20.5	31.7
3.7	3.8	3.7	3.3	4.4	4.6	4.9	7.2
280	273	264	235	222	219	201	199
284	275	268	255	224	220	218	198
2,380	2,786	2,772	2,084	2,235	2,389	2,343	2,200
5,126	5,111	5,111	4,551	4,325	4,688	4,967	4,942
1,405	1,531	1,779	1,731	1,567	1,648	1,843	1,913
2,350	2,204	2,202	2,058	1,974	1,950	1,965	1,218
—	—	396	390	390	390	—	—
8,881	8,846	9,488	8,730	8,256	8,676	8,775	8,073
40,673	45,002	42,482	38,750	41,012	48,614	45,736	48,891

Earnings coverage = net earnings attributable to shareholders + income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Return on capital employed = earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense / invested capital excluding AOCI

Dividend yield = dividends paid per common share / current year's close price

Dividend payout ratio = common share dividends declared / comparable funds from operations - 50 per cent dividends paid on preferred shares

Comparable funds from operations before interest to adjusted interest coverage = comparable funds from operations + interest on debt - interest income - capitalized interest / interest on debt + 50 per cent dividends paid on preferred shares - interest income

Dividend coverage = comparable cash flow from operating activities / cash dividends paid on common shares

Adjusted comparable funds from operations to adjusted net debt = comparable funds from operations - 50 per cent dividends paid on preferred shares / period-end long-term debt and finance lease obligations including fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents

Comparable EBITDA = operating income + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

Plant Summary

As of January 2019	Facility	Installed capacity(MW)[1]	Ownership (%)	Owned capacity (MW)[1][2]	Region	Revenue source	Contract expiry date
Coal 12 facilities	Sundance, AB	1,581	100%	1,581	Western Canada	Merchant[3]	–
	Keephills, AB	790	100%	790	Western Canada	Alberta PPA[4]/ Merchant[5]	2020
	Keephills 3, AB	463	50%	232	Western Canada	Merchant	–
	Genesee 3, AB	466	50%	233	Western Canada	Merchant	–
	Sheerness, AB	790	25%	198	Western Canada	Alberta PPA / Merchant [6]	2020
	Centralia, WA	1,340	100%	1,340	United States	LTC[7]/Merchant	2020-2025 [8]
Total Coal		5,430		4,373			
Gas 11 facilities	Poplar Creek, AB[9]	230	100%	230	Western Canada	LTC	2030
	Fort Saskatchewan, AB	118	30%	35	Western Canada	LTC	2029
	Sarnia, ON*	499	100%	499	Eastern Canada	LTC	2022-2025
	Ottawa, ON	74	50%	37	Eastern Canada	LTC/ Merchant	2017-2033
	Windsor, ON	72	50%	36	Eastern Canada	LTC/ Merchant	2031
	Parkeston, WA*[11]	110	50%	55	Australia	LTC	2026
	Southern Cross, WA*[10][11]	245	100%	245	Australia	LTC	2023
	South Hedland, WA* [11]	150	100%	150	Australia	LTC	2042
Total Gas		1,498		1,287			
Wind 21 facilities	Summerview 1, AB*	70	100%	70	Western Canada	Merchant	–
	Summerview 2, AB*	66	100%	66	Western Canada	Merchant	–
	Ardenville, AB*	69	100%	69	Western Canada	Merchant	–
	Blue Trail, AB*	66	100%	66	Western Canada	Merchant	–
	Castle River, AB* [12]	44	100%	44	Western Canada	Merchant	–
	McBride Lake, AB*	75	50%	38	Western Canada	LTC	2024
	Soderglen, AB*	71	50%	35	Western Canada	Merchant	–
	Cowley North, AB*	20	100%	20	Western Canada	Merchant	–
	Sinnott, AB*	7	100%	7	Western Canada	Merchant	–
	Macleod Flats, AB*	3	100%	3	Western Canada	Merchant	–
	Melancthon, ON* [13]	200	100%	200	Eastern Canada	LTC	2026-2028
	Wolfe Island, ON*	198	100%	198	Eastern Canada	LTC	2029
	Kent Breeze, ON*	20	100%	20	Eastern Canada	LTC	2031
	Kent Hills, NB*	167	83%	139	Eastern Canada	LTC	2035
	Le Nordais, QC*	98	100%	98	Eastern Canada	LTC	2033
	New Richmond, QC*	68	100%	68	Eastern Canada	LTC	2033
	Wyoming Wind, WY*	144	100%	144	United States	LTC	2028
	Lakeswind, MN*	50	100%	50	United States	LTC	2034
Total Wind		1,434		1,332			
Solar 1 facility	Mass Solar, MA* [14]	21	100%	21	United States	LTC	2032-2035
Total Solar		21		21			
Hydro 27 facilities	Brazeau, AB	355	100%	355	Western Canada	Alberta PPA	2020
	Bighorn, AB	120	100%	120	Western Canada	Alberta PPA	2020
	Spray, AB	112	100%	112	Western Canada	Alberta PPA	2020
	Ghost, AB	54	100%	54	Western Canada	Alberta PPA	2020
	Rundle, AB	50	100%	50	Western Canada	Alberta PPA	2020
	Cascade, AB	36	100%	36	Western Canada	Alberta PPA	2020
	Kananaskis, AB	19	100%	19	Western Canada	Alberta PPA	2020
	Bearspaw, AB	17	100%	17	Western Canada	Alberta PPA	2020
	Pocaterra, AB	15	100%	15	Western Canada	Merchant	–
	Horseshoe, AB	14	100%	14	Western Canada	Alberta PPA	2020
	Barrier, AB	13	100%	13	Western Canada	Alberta PPA	2020
	Taylor, AB*	13	100%	13	Western Canada	Merchant	–
	Interlakes, AB	5	100%	5	Western Canada	Alberta PPA	2020
	Belly River, AB*	3	100%	3	Western Canada	Merchant	–
	Three Sisters, AB	3	100%	3	Western Canada	Alberta PPA	2020
	Waterton, AB*	3	100%	3	Western Canada	Merchant	–
	St. Mary, AB*	2	100%	2	Western Canada	Merchant	–
	Upper Mamquam, BC*	25	100%	25	Western Canada	LTC	2025
	Pingston, BC*	45	50%	23	Western Canada	LTC	2023
	Bone Creek, BC*	19	100%	19	Western Canada	LTC	2031
	Akolkolex, BC (8)*	10	100%	10	Western Canada	LTC	2045
	Ragged Chute, ON*	7	100%	7	Eastern Canada	LTC	2029
	Misema, ON*	3	100%	3	Eastern Canada	LTC	2027
	Galetta, ON*	2	100%	2	Eastern Canada	LTC	2030
	Appleton, ON*	1	100%	1	Eastern Canada	LTC	2030
	Moose Rapids, ON*	1	100%	1	Eastern Canada	LTC	2030
	Skookumchuck, WA	1	100%	1	United States	LTC	2020
Total Hydro		948		926			
Total		9,331		7,939			

** TransAlta Renewables Inc. facility.*
(1) Megawatts are rounded to the nearest whole number; columns may not add due to rounding.
(2) Accounts for 100% of TransAlta Renewables assets. As of December 31, 2018, TransAlta owns approximately 61% of the outstanding shares of TransAlta Renewables.
(3) Merchant capacity refers to uprates on unit 3 (15 MW), unit 4 (53 MW), unit 5 (53 MW) and unit 6 (44 MW).
(4) PPA refers to Power Purchase Arrangement.
(5) Merchant capacity refers to uprates on unit 1 (12 MW) and unit 2 (12 MW).
(6) Merchant capacity refers to uprates on unit 1 (10 MW).
(7) LTC refers to Long-Term Contract.
(8) Contract is in place until 2025; however, one unit is set to retire in 2020.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) Comprised of four facilities.
(11) Gas/diesel.
(12) Includes seven individual turbines at other locations.
(13) Comprised of two facilities.
(14) Comprised of four ground-mounted projects and four roof-top projects.

Sustainability Performance Indicators

Corporate Statistics

Environment Health & Safety Management Systems	2018	2017	2016
Facilities with ISO 14001 and/or OHSAS 18001-based management systems (percentage)[1]	97	97	97
Management system audits[2]	17	20	**35**

Environmental Performance	2018	2017	2016
Resource or energy use[3]			
Coal combustion (tonnes)	10,001,100	14,956,400	**15,735,300**
Natural gas combustion (GJ)	69,372,900	55,520,900	**62,486,700**
Diesel combustion (L)	9,544,200	4,384,700	**46,179,400**
Gasoline consumption: vehicle (L)	1,414,600	1,476,700	**1,487,200**
Diesel consumption: vehicle (L)	38,361,500	44,045,200	**40,224,800**
Propane consumption: vehicle (L)	75,100	112,000	**78,800**
Electricity: building operations (MWh)	279,800	290,100	**359,300**
Natural gas: building operations (GJ)	73,100	75,500	**58,300**
Propane: building operations (L)	154,300	125,800	**127,500**
Kerosene: building operations (L)	115,600	96,200	**56,500**
Total resource or energy use (GJ)[4]	358,477,500	**496,910,700**	**528,442,800**
Greenhouse gas emissions[5]			
Carbon dioxide (tonnes CO_2e) √	20,595,600	29,627,700	**30,381,300**
Methane (tonnes CO_2e) √	68,900	107,100	114,200
Nitrous oxide (tonnes CO_2e) √	115,400	185,100	224,600
Sulfur hexafluoride (tonnes CO_2e)	10	10	20
Total greenhouse gas emissions[6] (tonnes CO_2e) √	20,779,900	**29,919,900**	**30,720,100**
Greenhouse gas emission intensity[7] (tonnes CO_2e / MWh) √	0.77	*0.86*	*0.83*
Air emissions[8]			
Total sulphur dioxide emissions (tonnes) √	19,300	**36,200**	**39,600**
Sulphur dioxide emission intensity[9] (kg / MWh) √	0.73	*1.05*	*1.08*
Total nitrogen oxide emissions (tonnes) √	28,000	**44,400**	**48,400**
Nitrogen oxide emission intensity[9] (kg / MWh) √	1.05	*1.29*	*1.33*
Total particulate matter emissions (tonnes) √	7,800	**14,500**	**13,800**
Particulate matter emission intensity[9] (kg / MWh) √	0.29	*0.42*	*0.38*
Total mercury emissions (kilograms) √	70	**110**	**130**
Mercury emission intensity[9] (mg / MWh) √	2.5	*3.29*	*3.52*
Water management[10]			
Water intake (million m^3) √	245	213	239
Water discharge (million m^3) √	208	172	197
Water consumption (million m^3) √	37	**41**	**42**
Water intensity (m^3/MWh)[11] √	1.4	*1.18*	*1.63*

Waste management[12]			
Non-hazardous			
Landfill (tonnes) √	1,900	3,200	2,100
Landfill (L) √	68,100	63,500	518,400
Ash disposal: mine (tonnes) [13]√	461,200	1,338,600	1,315,000
Ash disposal: lagoon (tonnes) [14] √	276,900	485,500	527,700
Recycled (tonnes) √	1,800	1,400	18,000
Recycled (L) √	3,718,100	4,122,700	212,100
Reuse (tonnes) √	564,400	827,400	700,700
Storage (tonnes) √	—	—	8,300
Hazardous[15]			
Landfill (tonnes) √	40	40	40
Landfill (L) √	45,100	14,600	13,110
Recycled (tonnes) √	40	12,740	60
Recycled (L) √	16,255,300	20,140,400	17,209,600
Land use and reclamation[16]			
Land used in mining activities – disturbed (cumulative hectares) √	12,400	12,100	11,800
Land used in mining activities – reclaimed (cumulative hectares) √	4,700	4,600	4,600
Land reclamation[17] ***(% of land disturbed) √***	***38***	***38***	***39***
Land used in mining activities: disturbed minus reclaimed (hectares) √	7,700	7,400	7,200
Land used by plants, offices and equipment (hectares) √	3,900	3,900	2,700
Total land use (cumulative hectares) √	**11,700**	**11,300**	**9,900**
Environmental incidents			
Total environmental incidents[18] **√**	**7**	**5**	**16**
Environmental enforcement actions[19]	1	—	—
Environmental fines ($ thousands)	6	—	—
Spills[20]			
Volume of significant spills (m^3)	5	15	61

Social Performance	2018	2017	2016
Workplace practices			
Employees	1,883	2,228	2,341
Number of full-time employees	1,810	2,125	2,267
Number of part-time employees	22	24	26
Number of contingent employees	51	79	48
Employees represented by independent trade union organizations[(21)] (%)	50	57	53
Voluntary employee turnover rate[(22)] (%)	20.22	10.65	6.71
Diversity			
Women in workforce (%)	20	19	18
Women in senior management (%)	50	26	26
Women on Board of Directors (%)	40	40	33
Health and safety			
Health and safety enforcement actions[(23)]	–	4	4
Health and safety fines ($ thousands)	–	–	5.4
Employee & contractor fatalities √	–	–	–
Lost time incident (LTI) (absence from work)[(24)] √	1	6	4
Medical aids (MA) (no absence from work)[(25)] √	12	15	20
Total injuries to employees & contractors √	13	21	24
Total injury frequency rate (IFR) (employees and contractors)[(26)] √	0.54	**0.72**	**0.85**
Total incident frequency (TIF) (employees and contractors)[(27)]	1.98	**3.54**	**3.29**
Community relations			
Community investments ($ millions)[(28)]	2.4	2.6	2.5

✓ 2018 data has been third-party assured to a limited assurance level by Ernst & Young LLP.
Please see "Discussion and Notes on Numbers" for footnote explanations.

Discussion and Notes on Numbers

TransAlta continually strives to improve the accuracy and coverage of our sustainability performance reporting to stakeholders. We review our processes and controls relating to the measurement and calculation of key sustainability data annually. Several footnotes appear throughout the statistical summary and are intended to provide clarity on specific boundary conditions, changes in methodology and definitions. For questions or clarity on any key performance indicators, please contact us at **sustainability@transalta.com.**

1. *ISO 14001 and ISO 18001 are the world's most recognized standards for Environmental Management and Health and Safety Management systems. TransAlta has ownership in 73 facilities.*
2. *Internal audits conducted against ISO management systems, regulatory frameworks and the Alberta Certificate of Recognition standard.*
3. *Energy use is calculated and reported from TransAlta-operated facilities, following the same approach we use for greenhouse gas (GHG) emissions reporting, which is the application of an Operational Control boundary.*
4. *Our 2016 energy data was revised in 2017, due to changes in our 2016 diesel combustion at our Centralia facility and 2016 natural gas combustion and diesel combustion at our Sarnia facility. Centralia 2016 diesel combustion was misreported in 2016. Sarnia 2016 energy data was misreported due to IT system-related errors. Sarnia 2016 vehicle diesel usage was applied incorrectly. Diesel usage was for a diesel backup generator and volumes were applied to diesel combustion and not diesel consumption from vehicles.*
5. *GHG emissions are calculated and reported from TransAlta-operated facilities in line with carbon regulations where the facility is located and with The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (specifically 'Setting Organizational Boundaries: Operational Control' methodology). As per the Operational Control methodology TransAlta reports 100 per cent of GHG emissions from facilities at which we are the operator. GHG emissions include emissions from stationary combustion, transportation use, building use and fugitive emissions.*
6. *Gross GHG emissions or gross carbon dioxide equivalent (CO_2e) emissions is the sum of carbon dioxide, methane, nitrous oxide and sulfur hexafluoride. Coincidentally the sum of scope 1 and 2 emissions will equate to gross CO_2e emissions or gross GHG emissions. Our 2016 GHG data was revised in 2017, due to changes in our 2016 diesel combustion at our Centralia facility and 2016 natural gas combustion and diesel combustion at our Sarnia facility. Please see Note 3 for revision explanations.*
7. *GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. Our 2017 nitrous oxide emissions were revised in 2018 to 185,100 tonnes CO_2e (previously reported as 190,900 tonnes CO_2e) as a result of double counting mobile combustion emissions at our Highvale mine. Our Australia 2016 production data was revised in 2017 due to metering issues in 2016. As a result our GHG intensity for 2016 dropped from 0.84 to 0.83 tonnes CO_2e/MWh.*
8. *Air emissions are reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is the application of an Operational Control boundary. Air emissions are expressed in tonnes, except for mercury emissions, which are represented in kilograms. Total particulate matter emissions (TPM) include both PM2.5 and PM10. In 2018 we revised our historical TPM emissions to include road dust total particulate matter emissions from our Highvale coal mine in Alberta. Our previous approach was to report on TPM stack emissions only, but as part of our continuous improvement process we have included road dust emissions. As a result, historical TPM volumes and emission intensities were adjusted to include TPM from Highvale mine road dust .*
9. *Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*
10. *Water usage is reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is the application of an Operational Control boundary. Total water consumed is measured by total water intake minus water discharge. Water is used primarily for cooling by our thermal power plants. Evaporative losses from the cooling ponds and cooling towers account for 95 per cent of the consumptive loss. The water lost to evaporation is not returned directly to the water body, but the water remains in the hydrologic cycle. Sundance 2015 and 2016 historical water data was revised in 2017 due to misalignment in reporting between corporate and business unit data. Water volumes that are discharged to our cooling pond, adjacent to Wabamum Lake, were being applied as intake volumes. These volumes are discharge volumes and have been reallocated accordingly.*
11. *Water intensity is calculated by dividing total operational water consumption (m^3) by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*
12. *Non-hazardous waste includes, but is not limited to, the disposal of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. Due to a vendor issue at our Hydro business unit, hazardous waste to landfill was estimated in 2018 using the average of hazardous waste to landfill from 2015-2017.*
13. *Ash disposal: mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal.*
14. *Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.*
15. *Hazardous wastes are substances going for disposal, which - either in the short or the long term - can be harmful to people, plants, animals or the environment.*
16. *Total land use is mining land use plus land used by plants, offices and equipment.*
17. *Disturbed land use Highvale mine volumes were reconciled in 2017 to match Alberta regulatory reporting data. Actual disturbed volumes in 2017 were 160 hectares and these volumes were reconciled with 80 hectares to ensure our total land disturbed volumes align. As a result our land reclamation percentage was down one per cent compared with 2016 data.*
18. *Environmental incidents are violations or non-compliance to regulations or exceedance of limits in company operating approvals that resulted in or had the potential to result in enforcement action.*
19. *Environmental enforcement actions are violations or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action, including stop work orders, fines or suspension of operating approvals*
20. *Spills volumes that require reporting to a regulatory agency or result in low level damage to ecosystem.*
21. *TransAlta has over 900 unionized workers working primarily at our operations.*
22. *Voluntary turnover is aligned with our Human Resources voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any full-time, part- time or contingent employee initiated exit, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover.*
23. *Health and safety enforcement actions are those resulting in a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.*
24. *Lost-time injuries (LTIs) are injuries that resulted in the worker being away from work beyond the day of the injury.*
25. *Medical aids (MAs) are injuries that resulted in medical treatment beyond first aid.*
26. *The injury frequency rate (IFR) measures work-related medical aid and lost-time injuries per 200,000 hours worked. IFR is calculated using a combination of actual and estimated exposure hours.*
27. *Total incident frequency (TIF) tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids) relative to employee hours worked.*
28. *Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.*

Independent Sustainability Assurance Statement

To the Board of Directors and Management of TransAlta Corporation ("TransAlta").

Scope of Ernst & Young LLP ("EY") Engagement
Our responsibilities included providing limited assurance over a selection of performance indicators as presented in the Addendum to this statement.

Subject Matter
We have performed limited assurance procedures for the following quantitative performance indicators ("Subject Matter") for the year ending December 31, 2018.

- Sulphur dioxide emissions and emission intensity (tonnes, kg/MWh)
- Nitrogen oxide emissions and emission intensity (tonnes, kg/MWh)
- Particulate matter emissions and emission intensity (tonnes, kg/MWh)
- Mercury emissions and emission intensity (kg, mg/MWh)
- Carbon dioxide emissions (tonnes CO_2e)
- Methane emissions (tonnes CO_2e)
- Nitrous oxide emissions (tonnes CO_2e)
- Total greenhouse gas emissions and emissions intensity (tonnes CO_2e, tonnes CO_2e/MWh)
- Total environmental incidents
- Lost-time incident for employees and contractors (LTI) (absence from work)
- Medical aids (MA) for employees and contractors (no absence from work)
- Total injuries to employees and contractors
- Employee and contractor total injury frequency rate (injuries/200,000 hours)
- Employee and contractor fatalities
- Water intake, discharge, consumption (million m^3)
- Water intensity (m^3/MWh)
- Waste management - Non-hazardous
  - Landfill (tonnes, L)
  - Ash disposal: mine, lagoon (tonnes)
  - Recycled (tonnes, L)
  - Reuse (tonnes)
  - Storage (tonnes)
- Waste management - hazardous
  - Landfill (tonnes, L)
  - Recycled (tonnes, L)
- Land use - disturbed and reclaimed

Criteria
TransAlta has prepared its specified performance information in accordance with industry standards and, where relevant, internally developed criteria.

TransAlta Management Responsibilities
The Subject Matter was prepared by the management of TransAlta, who is responsible for the assertions, statements and claims made therein including the assertions we have been engaged to provide limited assurance over, collection, quantification and presentation of the performance indicators and the criteria used in determining that the information is appropriate for the purpose of disclosure in this Report ("the Report"). In addition, management is responsible for maintaining adequate records and internal controls that are designed to support the reporting process.

EY Responsibilities
Our limited assurance procedures have been planned and performed in accordance with the International Standard on Assurance Engagements 3000 Assurance Engagements other than Audits or Reviews of Historical Financial Information.

Our procedures were designed to obtain a limited level of assurance on which to base our conclusion. The procedures conducted do not provide all the evidence that would be required in a reasonable assurance engagement and, accordingly, we do not express a reasonable level of assurance. While we considered the effectiveness of management's internal controls when determining the nature and extent of our procedures, our assurance engagement was not designed to provide assurance on internal controls and, accordingly, we express no conclusions thereon.

This assurance statement has been prepared for TransAlta for the purpose of assisting management in determining whether the Subject Matter is in accordance with the criteria and for no other purpose. Our assurance statement is made solely to TransAlta in accordance with the terms of our engagement. We do not accept or assume responsibility to anyone other than TransAlta for our work, or for the conclusions we have reached in this assurance statement.

Assurance Procedures
We planned and performed our work to obtain all the evidence, information and explanations considered necessary in relation to the above scope. Our assurance procedures included but were not limited to:

- Interviewing relevant personnel at the head office and at various sites to understand data management processes related to the selected performance indicators.
- Checking the accuracy of calculations performed - on a test basis - primarily through inquiry, variance analysis and performance of re-calculations.
- Assessing risk of material misstatement due to fraud or errors relating to the selected performance indicators.
- Evaluating the overall presentation of the Report, including the consistency of the Subject Matter.

Limitations of EY Work Performed
Our scope of work did not include expressing conclusions in relation to:

- The materiality, completeness or accuracy of data sets or information relating to areas other than the selected performance data, and any site-specific information.
- Management's forward-looking statements.
- Any comparisons made by TransAlta against historical data.
- The appropriateness of definitions for internally developed criteria.

Independence and Competency Statement
In conducting our engagement, we have complied with the applicable requirements of the Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants.

EY Conclusion
Based on our procedures for this limited assurance engagement described in this statement, nothing has come to our attention that causes us to believe that the Subject Matter is not, in all material respects, reported in accordance with the relevant criteria.

Ernst + Young LLP

Ernst & Young LLP
Calgary, Canada

February 26, 2019

Shareholder Information

Special Services for Registered Shareholders

Service	Description
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax splits and dividends without the delays resulting from address and ownership changes

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split(1)
December 31, 1992	Reorganization - TransAlta Utilities shares exchanged for TransAlta Corporation shares(2) 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.
(1) The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988 share split.
(2) TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

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

Common Share Dividends Declared in 2018

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.04
July 3, 2018	Jun. 1, 2018	May 31, 2018	$0.04
Oct 1, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.04
Jan. 1, 2019	Dec. 3, 2018	Nov. 30, 2018	$0.04
Apr. 1, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.04

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Chief Legal and Compliance Officer and Corporate Secretary of the Corporation.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $0.67724 per share from and including March 31, 2016, to, but excluding March 31, 2021.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2016, to but excluding March 31, 2021.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.01 per share from and including June 30, 2017, to, but excluding June 30, 2022.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.30 per share from and including September 30, 2017, to, but excluding Sept. 30, 2022.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.325 per share from the date of issue Aug. 15, 2014, to, but excluding Sept. 30, 2019.

Preferred Share Dividends Declared in 2018

Series A			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Mar. 31, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.16931
Jul. 3, 2018	Jun. 1, 2018	May 31, 2018	$0.16931
Sept. 30, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.16931
Dec. 31, 2018	Dec. 3, 2018	Nov. 30, 2018	$0.16931
Mar. 31, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.16931
Series B			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Mar. 31, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.23073
Jul. 3, 2018	Jun. 1, 2018	May 31, 2018	$0.22301
Sept. 30, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.20984
Dec. 31, 2018	Dec. 3, 2018	Nov. 30, 2018	$0.19951
Mar. 31, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.17889
Series C			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Mar. 31, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.25169
Jul. 3, 2018	Jun. 1, 2018	May 31, 2018	$0.25169
Sept. 30, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.25169
Dec. 31, 2018	Dec. 3, 2018	Nov. 30, 2018	$0.25169
Mar. 31, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.25169
Series E			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Mar. 31, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.32463
Jul. 3, 2018	Jun. 1, 2018	May 31, 2018	$0.32463
Sept. 30, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.32463
Dec. 31, 2018	Dec. 3, 2018	Nov. 30, 2018	$0.32463
Mar. 31, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.32463
Series G			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Mar. 31, 2018	Mar. 1, 2018	Feb. 28, 2018	$0.33125
Jul. 3, 2018	Jun. 1, 2018	May 31, 2018	$0.33125
Sept. 30, 2018	Sept. 4, 2018	Aug. 31, 2018	$0.33125
Dec. 31, 2018	Dec. 3, 2018	Nov. 30, 2018	$0.33125
Mar. 31, 2019	Mar. 1, 2019	Feb. 28, 2019	$0.33125

Dividends are paid on the last day of the month in March, June, September and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Voting Rights

Common shareholders receive one vote for each common share held.

Annual Meeting
The Annual and Special Meeting of Shareholders will be held at 10:30 a.m. MST, on Tuesday, April 16, 2019, at the Doherty Hall (Stampede Park) 623 13 Ave SE, Calgary, Alberta.

Transfer Agent
AST Trust Company (Canada)*
P.O. Box 700 Station "B"
Montreal, Quebec H3B 3K3

Phone
North America:
1.800.387.0825 toll-free
Toronto/outside North America:
416.682.3860
Email: inquiries@astfinancial.com

Fax
514.985.8843
Website
www.astfinancial.com/ca-en

Exchanges
Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols
TransAlta Corporation common shares: TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares: TSX: TA.PR.D, TA.PR.E, TA.PR.F, TA.PR.H, TA.PR.J

Additional Information
Requests can be directed to:
Investor Relations
TransAlta Corporation
110 - 12th Avenue SW
P.O. Box 1900, Station "M"
Calgary, Alberta T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

Email
investor_relations@transalta.com
Fax
403.267.7405
Website
www.transalta.com

* *AST Trust Company (Canada), formerly CST Trust Company, changed its name on July 20, 2017. CST Trust Company has succeeded CIBC Mellon Trust Company as our transfer agent. On Nov. 1, 2010, CIBC Mellon Trust Company sold its issuer services business to Canadian Stock Transfer Company Inc., which operated the business on their behalf until Aug. 30, 2013, at which time CST Trust Company, an affiliate of Canadian Stock Transfer Company Inc., received federal approval to commence business.*

Shareholder Highlights

Total Shareholder Return vs. S&P/TSX Composite Index
Year ended Dec. 31 *($)*

	09	10	11	12	13	14	15	16	17	18
TransAlta	100	95	100	77	74	61	31	49	50	38
S&P/TSX	100	118	107	115	130	144	132	160	175	159

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2009 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet

Ten-Year Market Value vs. Book Value
Year ended Dec. 31 *($ per share)*

	09	10	11	12	13	14	15	16	17	18
Market Value	23.48	21.15	21.02	15.12	13.48	10.52	4.91	7.43	7.45	5.59
Book Value	13.41	12.85	12.08	8.78	7.92	8.52	8.52	8.92	8.28	7.17

Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).

Source: FactSet and TransAlta

Monthly Volume and Market Prices
2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	9	10	18	8	10	8	17	18	10	11	8	16
TSX closing price *($ per share)*	6.80	7.16	6.98	6.76	6.67	6.60	7.41	7.67	7.27	6.95	7.12	5.59

Source: FactSet

Return on Common Shareholders' Equity
(%)

	09	10	11	12	13	14	15	16	17	18
ROE	6.9	9.6	10.6	(25.9)	(3.2)	6.3	(1.2)	5.4	(10.0)	(15.5)

Source: TransAlta

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair, Committee Chairs, President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by US domestic companies under the New York Stock Exchange's listing standards. Currently there are no differences between our governance practices and those of the New York Stock Exchange.

Ethics Helpline

The Board of Directors has established an anonymous and confidential Internet portal, email address and toll-free telephone number for employees, contractors, shareholders and other stakeholders to contact with respect to accounting irregularities, ethical violations or any other matters they wish to bring to the attention of the Board.

The Ethics Helpline phone number is **1.855.374.3801** (US/Canada) and **1.800.339276** (Australia)
Internet portal: **transalta.ethicspoint.com**
Email: T**A_ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**

TransAlta Corporate Officers

Dawn L. Farrell
President and Chief Executive Officer

Christophe Dehout
Chief Financial Officer

Jane N. Fedoretz
Chief Talent & Transformation Officer

Brett M. Gellner
Chief Strategy & Investment Officer

John H. Kousinioris
Chief Growth Officer & President of TransAlta Renewables Inc.

Dawn E. de Lima
Chief Officer - Business & Operational Services

Kerry O'Reilly
Chief Legal & Compliance Officer

Wayne A. Collins
Executive Vice-President, Coal and Mining Operations

Jennifer M. Pierce
Senior Vice-President, Business Development

Aron J. Willis
Senior Vice-President, Commercial, Gas & Renewables Operations

Todd J. Stack
Managing Director, Corporate Controller

Brent Ward
Managing Director, Treasury

Scott T. Jeffers
Managing Director, Corporate Secretary

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.

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

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.

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.

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British Thermal Units (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)
A gas that has the 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
A term used to describe assets that are not contracted and are exposed to market pricing.

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.

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

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

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.

This report was printed in Canada. The paper, paper mills and printer are all certified by the Forest Stewardship Council, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests.

TransAlta Corporation
110 - 12th Avenue SW
Box 1900, Station "M"
Calgary, Alberta
Canada T2P 2M1
403.267.7110
www.transalta.com

TransAlta™