THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE SITE EVALUATION COMMITTEE

DOCKET NO. SEC 2018-__

Joint Petition of Walden Green Energy Northeast Wind LLC, Walden Antrim LLC and Antrim Level LLC for Approval of the Transfer of Membership Interests in Antrim Wind Energy, LLC.

PRE-FILED DIRECT TESTIMONY OF BRENT WARD AND KELLY WIST ON BEHALF OF ANTRIM LEVEL LLC AND TRANSALTA CORPORATION

Qualifications of Brent Ward – General Financial Information and Capability

Q. Please state your name, position, and business address.

A. My name is Brent Ward. I am the Managing Director & Treasurer at TransAlta Corporation ("TransAlta"). My business address is 110 – 12 Avenue SW, Calgary, Alberta, Canada.

Q. Please describe your relevant work experience and education.

A. I have been employed at TransAlta for over 17 years and have held my current position of Managing Director & Treasurer since April 2017. In my current role, I have led oversight of all Corporate Finance, Cash Management, Insurance and Pension initiatives and am a key contact for banks, ratings agencies and fixed income investors. I am accountable for all funding initiatives at TransAlta and, since 2011, I have raised over CAD$4 billion across a broad range of financing alternatives including common equity, preferred shares, debt capital markets and project finance. As well, I have also led all corporate finance initiatives including capital markets transactions, bank market transactions, financing plants and structures, FX and interest rate derivative programs, ratings agency oversight and analysis, credit, and growth due diligence initiatives. With regards to the Antrim Wind Project (or "Project"), my role has been primarily focused on the funding requirements for the project. In addition, during my time with TransAlta, I previously led all Investor Relations initiatives and strategies including communicating financial results, developing marketing roadshows, and managing sell-side analyst and institutional investor relations. I have also led three teams that provided business valuation expertise to Corporate Planning & Strategic Analysis, Acquisitions & Divestitures, greenfield opportunities and portfolio optimization. I graduated from Lakehead University in 1994 with a Bachelor of Commerce degree and I was awarded a Chartered Financial Analyst designation from the CFA Institute in 1999. My full resume is attached as **Exhibit A**.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information about TransAlta's general experience in project finance and the company's general financial profile and capabilities in support of the Joint Petition of Walden Green Energy Northeast Wind LLC, Walden Antrim

LLC – and Antrim Level LLC for Approval of the Transfer of Membership Interest in Antrim Wind Energy, LLC ("Joint Petition").

<u>Qualifications of Kelly Wist – Project Finance</u>

Q. Please state your name, position, and business address.

A. My name is Kelly Wist. I am the Managing Director of Mergers and Acquisitions and Strategic Corporate Development at TransAlta. My business address is 110 – 12 Avenue SW, Calgary, Alberta, Canada.

Q. Please describe your relevant work experience and background.

A. I am currently employed at TransAlta Corporation as Managing Director, Mergers and Acquisitions and Strategic Corporate Development, a position I have held since 2015. I have been a part of TransAlta's growth team since I joined the company in 2007. While at TransAlta, I have led or made a significant contribution to over CAD$3 Billion in growth investments, including the CAD$1.6 Billion acquisition of Canadian Hydro Developers, the acquisition of the Solomon Power Project in Western Australia, TransAlta's first acquisition of solar generation, as well as all of TransAlta's wind generation facilities in the United States. I was also instrumental in the spin-off of TransAlta's renewable assets into a new publicly traded yield-oriented vehicle, TransAlta Renewables, Inc.

My role on the pending acquisition of the Antrim Wind Project is as TransAlta's business lead, overseeing the due diligence, analysis and approval process, as well as negotiation of the contractual agreements, including the Purchase and Sale Agreement between the parties to the Joint Petition.

My professional background is in corporate finance, valuations, and mergers and acquisitions. I completed my Master of Business Administration studies at the University of Saskatchewan in 1998. Upon graduating, I spent two years consulting in the areas of logistics and transportation. In 2000, I was hired as a Financial Analyst with Canadian Pacific Railway. I worked with Canadian Pacific Railway for over 6 years. While at Canadian Pacific Railway, I spent two years in corporate planning and financial analysis, responsible for analysis of major capital expenditures and growth projects. I then spent four years as Manager, Corporate Finance and Capital Markets, where I secured over CAD$2 Billion in financing for the corporation.

In 2006, I assumed the role of Manager, Financial Analysis at Fort Chicago Energy Partners, LP. While at Fort Chicago, I developed the corporate planning process, and in-house analysis capabilities for mergers and acquisitions. I was a key contributor to Fort Chicago's first major acquisition of power generation assets, the CAD$200 Million acquisition of Countryside Power Income Fund in 2007.

I hold a Bachelor of Arts (Public Administration) degree, awarded in 1995 from the University of Saskatchewan. I also hold a Master of Business of Administration degree from the University of Saskatchewan, awarded in 1998. In addition, I hold a Chartered Financial Analyst designation awarded in 2006. My full resume is attached as **Exhibit B**.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address how TransAlta intends to finance the pending acquisition, construction, and operation of the Antrim Wind Project, and its commitment to comply with all conditions of the Order and Certificate of Site and Facility with Conditions, dated March 17, 2017 (the "Certificate"), in support of the Joint Petition.

Q. Please briefly describe the proposed transaction.

A. Walden Green Energy Northeast Wind LLC ("Walden NE") and Walden Antrim LLC, owners of 100% of the membership interests in Antrim Wind Energy, LLC ("AWE"), have entered into a Purchase and Sale Agreement ("PSA"), dated as of February 20, 2018, with Antrim Level LLC, to sell all of the membership interests in AWE to Antrim Level LLC. Antrim Level LLC, a Delaware limited liability company, was formed to be the acquisition entity for TransAlta's purchase of the membership interests in AWE as well as the purchase of the membership interests in Big Level Wind LLC, the owner of a 90 MW wind development project in Pennsylvania. Walden NE was also the seller of Big Level Wind and that transaction closed on February 20, 2018.

AWE currently holds a Certificate granted by the New Hampshire Site Evaluation Committee ("SEC") in March 2017 and affirmed by the New Hampshire Supreme Court. AWE will remain the Certificate holder if the Joint Petition is approved. As required by the Certificate, any change in ownership or ownership structure of AWE must be approved by the SEC. The Joint Petition seeks SEC approval of the sale of 100% of the membership interests in AWE to

Antrim Level LLC. Upon closing of the transaction under the PSA, TransAlta Holdings U.S. Inc., a wholly owned subsidiary of TransAlta Corporation, will own all of the membership interests in AWE.

The PSA contains a number of conditions precedent to closing the sale of AWE to Antrim Level LLC. One such condition is the SEC's approval of the Joint Petition. Other conditions include conditions customary in transactions of this nature.

Q. Brent Ward - Please provide an overview TransAlta Corporation and any other relevant entities involved in this transaction.

A. TransAlta Corporation is a power generation company and marketer of wholesale electricity and is publicly traded on both the New York Stock Exchange ("NYSE") and the Toronto Stock Exchange ("TSX") with a current market capitalization of approximately CAD$1.9 Billion. As of the First Quarter of 2018, TransAlta had approximate revenues of CAD $588 million, approximate total assets of CAD $9.963 billion, and approximate cash on hand of CAD $329 million. TransAlta's financial reports are filed with the U.S. Securities and Exchange Commission and can be accessed at TransAlta's website at www.transalta.com under "Investors." TransAlta's First Quarter Report for 2018 is attached hereto as **Exhibit C**. TransAlta's financial reports are also filed with SEDAR. SEDAR is the System for Electronic Document Analysis and Retrieval, the electronic filing system for the disclosure documents of public companies and investment funds across Canada (similar to EDGAR in the United States). TransAlta's focus has been in the development, production and sale of electric energy. TransAlta, through various subsidiaries, owns and operates a portfolio of assets totaling over 9,000 MW located across Canada, the United States and Australia. TransAlta's operating fleet is comprised of a varied mix of fuel types including coal, natural gas, diesel, hydroelectric, wind and solar generation at more than 60 facilities. A full list of TransAlta's operating portfolio can be found in the attached **Exhibit D**.

TransAlta Corporation, through its subsidiary TransAlta Holdings U.S. Inc., will be the ultimate parent of Antrim Level LLC, the entity that will directly own 100% of the membership interests of AWE once the proposed transaction closes. In 2013, TransAlta Renewables, of which TransAlta currently owns approximately 61%, completed its initial public offering. TransAlta

Renewables was formed to hold a highly contracted portfolio of renewable and natural gas assets to provide stable and consistent cashflows and to pursue and capitalize on strategic growth opportunities. TransAlta Renewables will hold an economic interest in Antrim Level LLC by way of an investment in tracking preferred shares, which are an investment in preferred shares of subsidiaries of TransAlta that pay dividends based on tracking certain financial results of Antrim Level, LLC. This mechanism is utilized as it is a more tax efficient structure than a direct investment by TransAlta Renewables. Please refer to the simplified corporate structure diagram attached as **Exhibit E**.

TransAlta has very strong executive leadership capabilities with decades of experience in the Independent Power Producer sector. Biographies of TransAlta's executive leadership team are attached as **Exhibit F**.

Q. Kelly Wist - Please describe TransAlta's experience as a wind facility owner and operator.

A. TransAlta is a highly experienced wind facility owner and operator and is one of the largest generators of wind power in Canada. TransAlta maintains a low risk profile through operating a highly-contracted set of assets that are diversified in terms of both geography and fuel type. This, along with an on-going focus on maintaining a strong financial condition, has resulted in the credit ratings for TransAlta Corporation illustrated below:

	DBRS	**Standard & Poors**	**Moody's**	**Fitch**
Issuer Rating	BBB (low) / Stable	BBB- / Negative	Ba1 / Positive	BBB- / Stable

In the past 15 years, TransAlta has constructed 7 wind facilities for which it has financed the construction for each of those projects with capital raised at the corporate level. TransAlta has also raised CAD$1.1B of project level financing though five separate financings of projects that were already in operation. TransAlta is therefore very experienced in multiple forms of financing. In addition, TransAlta has access to multiple other sources of capital including the Canadian debt capital markets, the US debt capital markets, the equity capital markets, preferred shares, tax equity and access to CAD$2 billion in committed credit facilities. In addition, TransAlta is also highly experienced in managing the financial aspects of its operating portfolio of 18 wind projects totaling net 1,321 MW. For each of these wind projects, TransAlta performs asset management duties including oversight and management of financing, budgeting, medium and long range asset plans, long range technical plans, asset and enterprise risk action plans, stage gate capital processes, productivity and business improvement initiative programs, and accounting and reporting for each of its operating assets. These asset management programs support our strategic priorities of unlocking additional value from our base assets, strengthening our financial position and enabling growth.

Q. Brent Ward - Please discuss TransAlta's approach for financing the construction and operation of renewable energy projects.

A. TransAlta has successfully acquired numerous renewable generation projects throughout North America to grow its fleet. Most recently, TransAlta acquired the 90 MW Big Level Wind project located in Pennsylvania in early 2018. Big Level Wind was a fully permitted and construction-ready project at the time of purchase. Construction for Big Level has recently started and will be funded through a CAD$150 million equity offering by TransAlta Renewables, which closed on June 22, and drawing on the TransAlta Renewables credit facility. In addition, TransAlta acquired the 50 MW Lakeswind wind project located in Minnesota and the 21 MW Mass Solar portfolio located in Massachusetts in 2015 for an equity purchase price of USD$75.8 Million. At transaction close, TransAlta also assumed USD$41.8 Million of existing project debt at Mass Solar and certain tax equity financing obligations of Lakeswind and funded the equity through its credit facility and cash on hand. In addition, the USD$102 Million acquisition of the 144 MW Wyoming Wind facility occurred in 2013 and was funded through cash on hand.

In addition, TransAlta has been successful in completing numerous project financing deals and has secured project financing for four of its wind facilities. In October 2017, TransAlta Renewables completed project financing on its Kent Hills wind facility in New Brunswick in the amount of CAD$260 million, a portion of which was used to fund the construction of the Kent Hills 3 facility, a 17.25 MW expansion on the existing wind farm. In June 2016, TransAlta Renewables completed project financing on its New Richmond wind facility in Quebec in the amount of CAD$159 million and in October 2015, completed project financing on its Wolfe Island and Melancthon wind facilities in Ontario in the amount of CAD$442 million.

Q. Brent Ward - How does TransAlta intend to finance the construction of Antrim Wind?

A. TransAlta intends to finance the construction of Antrim Wind through a combination of cash on hand and drawing on the TransAlta Renewables credit facility. As of June 30, 2018, TransAlta Renewables had a CAD $500 million Credit Facility of which only CAD $91 million has been drawn. This undrawn capacity of CAD $409 million under the facility is available to us for general corporate purposes including construction capital requirements. This amount is many times greater than the $63-$65 million construction cost for the Project. In addition, on June 22, 2018, TransAlta Renewables closed a CAD $150 million equity offering that is part of our long-term financing solutions for both the Big Level and Antrim Wind projects. Once Antrim Wind reaches commercial operation, its permanent capital structure will include TransAlta equity and third party tax equity, as is customary for multiple U.S. wind projects owned by large corporates. TransAlta has had a number of discussions with various U.S. banks in its syndicate about providing the tax equity for the Project and the appetite for investing in the Project is strong. A number of tax equity investors outside TransAlta's syndicate have also expressed an interest in investing the Project. The appetite for a tax equity investment in the Project has proven to be very robust. TransAlta will engage in more fulsome discussions with those tax equity investors early in 2019.

Q. Brent Ward - Is this approach consistent with TransAlta's approach for financing the construction of renewable projects it has acquired in the past?

A. Yes, the plan to finance the construction of Antrim Wind is consistent with the approach TransAlta has taken in the past and would take for financing the construction of any renewable project located in the United States. As discussed earlier, this is also the same structure being utilized for the construction of the 90 MW Big Level wind project, which is currently under construction and expected to commence operations in 2019.

Q. Kelly Wist – Please describe Antrim Level's role during the construction of the Antrim Wind project prior to the closing under the PSA.

A. Subject to favorable resolution of the appeal of the Certificate to the New Hampshire Supreme Court, Antrim Level agreed to provide financing for substantially all amounts reasonably requested by AWE to satisfy all obligations under the EPC Agreement between AWE and Reed & Reed, Inc., the obligations under AWE's Large Generator Interconnection Agreement with Eversource Inc., and the obligations under the Turbine Supply Agreement between AWE and Siemens Energy, Inc. Now that the appeal to the New Hampshire Supreme Court is final and the Certificate has been affirmed, AWE will use debt financing provided by Antrim Level to continue construction of the Project. This financing arrangement is governed by a Promissory Note from Walden NE to Antrim Level, LLC and secured by a Pledge Agreement. In the event that the Transfer of Membership Interests in AWE is not approved, AWE will complete construction of the Project with funding provided by Walden, as previously indicated to the SEC, and the debt will be repaid to Antrim Level like any other traditional debt instrument.

Q. Brent Ward - Please explain Antrim Level's financial capability, as a subsidiary of TransAlta, to operate Antrim Wind if this transfer is approved.

A. A large component of TransAlta's business is in the development, construction and operation of generation facilities. As we are one of the largest wind generators in Canada, with an expanding portfolio in the United States, we are highly experienced in each of these areas and know how to capitalize on our strengths. We are committed to our facilities and have managed numerous projects of different fuel types, including wind, from the beginning of development through to years of successful operation and recently decommissioned Canada's first operating wind facility in Alberta – thus we are directly experienced in managing the finances of North American wind projects through every stage of the wind farm lifecycle.

TransAlta has a solid record for successfully operating its wind facilities to ensure strong cash flow. We have over 1,300 MW of wind capacity in our portfolio, which is diversified across geographic locations as well as diversified in the type of technology utilized. This diversification supports strong and stable cashflows, and limits exposure should the production of any one project be lower than expected in any given year. In addition, TransAlta believes that a conservative wind resource estimate was utilized in its evaluation of Antrim, providing greater opportunity for upside in a revenue forecast once the project reaches operation in comparison to any potential loss should the forecast be less than expected. TransAlta utilizes its own experienced in-house wind resource analytical team to estimate the production potential of a proposed wind facility. In most cases, including in the case of Antrim Wind, TransAlta's internal production estimate is more conservative than that of a third-party. Proving the economic validity of a project using a more conservative production estimate adds credibility to the value of the investment. In any event, regardless of any variation in annual wind resource, TransAlta has the financial strength to ensure that all conditions of the existing Certificate continue to be met through to final decommissioning.

At Walden's request and pursuant to the agreed financing package between Walden and TransAlta, we have already posted the required decommissioning security as approved by the Town of Antrim on behalf of Antrim Wind Energy, LLC for the Antrim Wind Project. Upon change of control, TransAlta will assume the continuing obligation of the decommissioning funding assurance as outlined in the agreement between the Town of Antrim and Antrim Wind Energy LLC. We are committed to our projects and the communities in which they operate. We look forward to the opportunity to be the owner of Antrim Wind and complying with all commitments contained in existing contracts between Antrim Wind Energy, LLC and various third parties, including the Town of Antrim, as well as the Certificate.

Q. Do you both believe Antrim Level LLC has the requisite financial capability to construct and operate the Antrim Wind facility?

A. Yes. As a subsidiary of TransAlta Corporation, Antrim Level LLC will have the financial resources and financial experience to ensure successful construction and operation of the Antrim Wind facility in continuing compliance with the terms and conditions of the Certificate.

Q. Does this conclude your testimony?

A. Yes.

PRE-FILED DIRECT TESTIMONY OF BRENT WARD AND KELLY WIST ON BEHALF OF ANTRIM LEVEL LLC AND TRANSALTA CORPORATION

LIST OF EXHIBITS

Exhibit A - Resume of Brent Ward

Exhibit B - Resume of Kelly Wist

Exhibit C - TransAlta's First Quarter Report for 2018

Exhibit D - TransAlta's Operating Portfolio

Exhibit E - TransAlta's Simplified Corporate Ownership Structure

Exhibit F - Biographies of TransAlta's Executive Leadership Team

BRENT WARD, CFA

1005 Russet Road NE
Calgary, AB
T2E 5L2

W (403) 267-2519 / C (403) 512-5562 / Email: bvward@shaw.ca

PROFESSIONAL HIGHLIGHTS

- Standing member of TransAlta's internal Investment Committee reviewing growth and productivity initiatives
- Represented TransAlta externally as head of Investor Relations, marketing of our private placements, presenting at conferences and managed key banking and rating agency relationships
- Raised approximately $4 billion in the capital markets including common equity, preferred shares, initial public offering (IPO) of TransAlta Renewables, secondary offerings, US & CAD Public Debt Capital Markets, secured amortizing private placements and bank financings
- Led the renewal and negotiation of multiple credit facilities including the syndicated revolver, bilateral credit facilities and LC facilities
- Significantly expanded Investor Relations program and marketing by tripling our institutional investor interactions in 2014 compared to 2012
- Delivered the annual Long-Range Forecast (2005 – 2010) and the annual budget (2006, 2009 - 2011) at TransAlta
- Delivered defense analysis to TransAlta management (2007 / 2008) related to an activist shareholder & takeover attempt
- Awarded 6 Above & Beyond bonus awards at TransAlta for performance excellence as well as retention bonus in 2009

EMPLOYMENT HISTORY

TransAlta Corporation – Calgary, AB

Managing Director & Treasurer **Apr 2017 – present**
Led oversight of all Corporate Finance, Cash Management, Insurance and Pension initiatives. Key contact for banks, ratings agencies and fixed income investors

Director, Corporate Finance **Jan 2011 – April 2017**
Led all Corporate Finance initiatives including capital markets transactions, bank market transactions, financing plans & structures, FX and interest rate derivative programs, ratings agency oversight and analysis, credit and growth due diligence initiatives. Key contact for banks, ratings agencies and fixed income investors

Director, Corporate Finance & Investor Relations **Feb 2013 – Sep 2015**
In addition to Corporate Finance, I was expanded to lead all Investor Relations initiatives and strategies including communicating financial results, developing marketing roadshows, managing sell-side analyst and institutional investor relationships. The addition of IR to my role was meant to be temporary, but lasted 2 ½ years

Director, Strategic Finance **Aug 2007 – Dec 2010**
Led 3 teams that provided business valuation expertise to Corporate Planning & Strategic Analysis, Acquisitions & Divestitures, greenfield opportunities and portfolio optimization

Portfolio Manager **Jul 2006 – Aug 2007**
Evaluated fleet of assets based on corporate strategies, risk and financial measures. Evaluated various hedge optimization strategies and conducted due diligence on acquisition targets and in determining corporate impacts

Manager, Corporate Planning **Dec 2004 – Jul 2006**
Delivered consolidated financials for the monthly estimate, annual Budget and Long-Range Forecast and any related scenario analysis

Senior Analyst, Investor Relations **Oct 2003 – Dec 2004**
Liaison between the investment community and senior management. Assisted in the preparation of all public documents and presentations and responded to investor / analyst queries

Senior Analyst, Corporate Development **Mar 2001 – Oct 2003**
Delivered economic analysis of development and acquisition opportunities and interfaced with internal and external professionals

United Communities Inc. – Calgary, AB – Financial Analyst **Jun 1998 – Mar 2001**

Scotia Direct Investing – Calgary, AB – Investment Representative **Jan 1997 – Jun 1998**

Canada Trust – Calgary, AB – Financial Services Officer **Sep 1995 – Jan 1997**

EDUCATION

Bachelor of Commerce Degree
Lakehead University
Thunder Bay, ON
1990 – 1994

Chartered Financial Analyst
CFA Institute
Charlottesville, VA
1999

COMPUTER SKILLS

MS Excel, Word, Power Point

PROFESSIONAL DEVELOPMENT

- Canadian Power Finance Conference - Euromoney (2013, 2017 & 2018)
- American Finance Professionals (AFP) - Annual Conference (2015)
- Director Training – Eagles Flight (2009 - 2012)
- Effective Negotiating – Karrass (2010)
- Corporate Valuation – Euromoney (2006)
- 7 Day Leadership Program – The Banff Centre (2004)
- Advanced Business Valuations – CICA (2002)
- Creative Negotiating – CICA (2002)
- Finance Workshop – University of Calgary – (2001)
- Electric Asset and Portfolio Valuation – InfoCast (2001)
- Canadian Options Course - CSI (1997)
- Conduct & Practices Handbook Exam – CSI (1994)
- Canadian Securities Course - CSI (1994)

Kelly B. Wist **BA, MBA, CFA**

EXHIBIT B

Education

2006 — **Chartered Financial Analyst**
CFA Institute

1998 — **Master of Business Administration**
University of Saskatchewan

1995 — **Bachelor of Arts (Public Administration)**
University of Saskatchewan

Work Experience

2007-Present

Managing Director, M&A and Strategic Corporate Development — **TransAlta Corporation**

- Accountability for growth in Eastern Canada and the United States of America
- Successfully grown US renewables business from a base of zero to over 200 MW including TransAlta's first operating solar generation facilities
- $61 Million divestiture of TransAlta's interest in the Wintering Hills wind facility
- Financial oversight on all corporate investment opportunities

Manager, Mergers and Acquisitions — **TransAlta Corporation, Calgary, AB**

- Canadian lead on $300 Million acquisition of the Solomon Power Station
- Key Contributor on the $200 Million Initial Public Offering of TransAlta Renewables Inc.
- Responsibility for corporate growth through M&A, including successful $1.6 Billion acquisition of Canadian Hydro Developers
- Lead the evaluation, due diligence and execution on all corporate M&A opportunities

2006 – 2007

Manager, Financial Analysis — **Fort Chicago Energy Partners LP, Calgary, AB**

- Financial lead on M&A team, including the successful $200M acquisition of Countryside Power
- Created the Partnership's corporate financial model for existing businesses and Greenfield projects
- Business Development lead on the Khalix (Accounting and Finance System) Implementation Team
- Key liaison with investment banks on M&A opportunities

2000 – 2006

Divisional Finance Officer — **Canadian Pacific Railway, Calgary, AB**

- Senior financial advisor with financial oversight for annual revenue portfolio of $3.4 Billion
- Financial accountability for commercial contracts, capital expenditures, and corporate governance

Manager, Corporate Finance & Capital Markets — **Canadian Pacific Railway, Calgary, AB**

- Overall responsibility for planning, review, analysis, negotiation, and execution of all company financing transactions for debt and equipment both in Canada and the United States
- Lead financing transactions with cumulative value of over $1 Billion
- Development, planning, and implementation of optimal financing strategy

Financial Analyst — **Canadian Pacific Railway, Calgary, AB**

- Financial/Economic analysis of all major discretionary capital projects in excess of $3.0 Million
- Coordination and modeling of the company's four-year strategic financial plan
- Negotiated purchases of leased equipment to lower company equipment rents expense

1998 – 2000

Logistics Analyst / Consultant — **LMS Inc., Saskatoon, SK**

- Extensive use of Geographic Information System (GIS) technology to solve business logistics and transportation problems/issues (facility location, distribution cost analyses, transportation modeling)

TransAlta™

TRANSALTA CORPORATION
First Quarter Report for 2018

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See the Forward-Looking Statements section of this MD&A for additional information.

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three months ended March 31, 2018 and 2017, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2017 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", and "TransAlta" refers to TransAlta Corporation and its subsidiaries. Our condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") *34 Interim Financial Reporting* for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at March 31, 2018. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated *May 7, 2018*. Additional information respecting TransAlta, including its 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.

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 financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income in our Condensed Consolidated Statements of Earnings (Loss) for the three months ended March 31, 2018 and 2017. 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 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, comparable FFO, FCF, and cash flow generated by the business are non-IFRS measures that are presented in this MD&A. See the Reconciliation of Non-IFRS Measures and Discussion of Segmented Comparable Results sections of this MD&A for additional information.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are presented for general information purposes only and not as specific investment advice. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "project", "estimate", "forecast", "foresee", "potential", "enable", "continue", or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to: our business model and anticipated future financial performance; our success in executing on our growth projects; the timing of the construction and commissioning of projects under development, including the Brazeau Hydro pumped storage Project, the Kent Hills 3 Wind Project, the Pennsylvania and New Hampshire wind projects, and their attendant costs and sources of funding; the benefits of the Brazeau Hydro Pumped Storage project; the pre-tax savings to be delivered by Project Greenlight; spending on growth and sustaining capital and productivity projects, including in connection with Project Greenlight; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; purchases of shares under the Normal Course Issue Bid ("NCIB"); the regulatory developments, including the Federal Governments release of regulations for gas-fired generation; the ruling by the Alberta Utilities Commission ("AUC") in respect of line losses including our estimated maximum exposure; the section titled "2018 Financial Outlook"; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2018 comparable earnings before interest, depreciation and amortization ("EBITDA"), funds from operations ("FFO") and free cash flow ("FCF"), and expected sustaining capital expenditures; Canadian Coal Fleet availability and capacity factor; contributions to gross margin for Energy Marketing in 2018; significant planned major outages in 2018 and lost production; expected governmental regulatory regimes and legislation, including the Government of Alberta's intended shift to a capacity market and the expected impacts 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; expectations in respect of generation availability, capacity, and production; power prices in Alberta, Ontario, and the Pacific Northwest; expected financing of our capital expenditures; the anticipated financial impact of increased carbon prices, including under the Carbon Competitiveness Incentive Regulation ("CCIR") in Alberta; our trading strategies and the risk involved in these strategies; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar, the Australian dollar, and other currencies in which we do business; our exposure to liquidity risk; expectations in respect of the global economic environment; expected cost savings and payback periods following the implementation of Project Greenlight and productivity initiatives; expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of TransAlta Renewables; the refinancing of our upcoming debt maturities over the next two years; expectations regarding our de-leveraging strategy; expectations in respect of our community initiatives; impacts of future IFRS standards and the timing of the implementation of such standards; and amendments or interpretations by accounting standard setters prior to initial adoption of those standards.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; ability to compete effectively in the anticipated Alberta capacity market; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; growth, whether through acquisition or greenfield development; unanticipated operating conditions; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, sun, or wind required to operate our facilities; natural or man-made disasters; physical risks related to climate change; the threat of terrorism and cyberattacks and our ability to manage such attacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing and the ability to access financing at a reasonable cost and on reasonable terms; our ability to fund our growth projects; our ability to maintain our investment grade credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; outcomes of legal, regulatory, and contractual proceedings involving the Corporation including those with Fortescue Metals Group LTd. ("FMG"); outcomes of investigations and disputes; reliance on key personnel; labour relations matters; risks associated with development projects and acquisitions, including delays or changes in costs in the construction and commissioning of our two new US wind projects and the Kent Hills 3 wind project; and the maintenance or adoption of enabling regulatory frameworks or the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives, including as it pertains to coal-to-gas conversions.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our MD&A for our 2017 annual consolidated financial statements and under the heading "Risk Factors" in our 2018 Annual Information Form.

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

Highlights

3 months ended March 31	2018	2017
Revenues	**588**	578
Net earnings (loss) attributable to common shareholders	**65**	—
Cash flow from operating activities	**425**	281
Comparable EBITDA[1, 2]	**416**	274
FFO[1, 2]	**318**	202
FCF[1, 2]	**238**	96
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.23**	—
FFO per share[1, 2]	**1.10**	0.70
FCF per share[1, 2]	**0.83**	0.33
Dividends declared per common share	**0.04**	—

As at	March 31, 2018	Dec. 31, 2017
Total assets	**9,963**	10,304
Total consolidated net debt[3]	**3,081**	3,363
Total long-term liabilities	**4,638**	4,311

(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 Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(2) During the fourth quarter of 2017, we revised our approach to reporting adjustments to arrive at FFO, mainly to better represent FFO as a cash metric. Previously, FFO was adjusted to include, exclude, or to modify the timing of cash impacts related to adjustments made in arriving at comparable EBITDA. As a result, comparable EBITDA, FFO, and FCF for 2017 has been revised accordingly.
(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 net debt.

Our performance during the first quarter was similar to last year after adjusting for the Sundance B and C PPA termination payment in 2018 and the settlement of a PPA indexation dispute with the Ontario Electrical Financial Corporation ("OEFC") in 2017. Availability from our coal generating assets in Alberta was solid during the quarter at 90.5 per cent compared to last year of 83.7 per cent. Prices in Alberta increased almost 60 per cent to $35/MWh to reflect the impact of carbon taxes paid by certain generators. During the first quarter of 2018, our results included $157 million relating to the early termination of the Sundance B and C PPA, to replace future capacity payments we would have received over the next 3 years. We are disputing the amount received from the Balancing Pool as we believe an additional $56 million is due to us under the terms of the PPAs. Last year's results included $17 million relating to our share of the settlement of a prior years indexation dispute with the OEFC. Excluding these unusual payments in 2018 and 2017, our FCF for the quarter would have been $81 million ($0.28 per share) and $79 million ($0.27 per share), respectively.

In January, we permanently shut down Sundance Unit 1 and mothballed Sundance Unit 2 following the scheduled expiry of the Power Purchase Arrangements with the Balancing Pool for these two units, reducing our installed capacity from our Canadian Coal segment by 560 MW or 14 per cent. Last year, comparable EBITDA generated by these two units totalled $12 million.

Net earnings attributable to common shares totalled $65 million during the quarter compared to nil last year, due mostly to the positive contribution of the $157 million ($115 million after-tax) Sundance B and C PPA termination payment.

Segmented Cash Flow Generated by the Business

3 months ended March 31	2018	2017
Segmented cash inflow (outflow)		
Canadian Coal[1]	**208**	56
US Coal	**18**	3
Canadian Gas[2]	**60**	83
Australian Gas	**31**	30
Wind and Solar	**65**	65
Hydro	**16**	12
Generation cash inflow	**398**	249
Energy Marketing	**(18)**	5
Corporate	**(25)**	(26)
Total comparable cash inflow	**355**	228

(1) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018.
(2) Includes $17 million (our share) from the OEFC to settle an relating to the settlement of a prior years indexation dispute.

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. Cash flow generated by the business totalled $355 million during the first quarter of 2018, up $127 million compared to the same quarter in 2017. Despite higher availability in the first quarter, and higher prices, Canadian Coal's cash flow, excluding the termination payment, was down $5 million from 2017 due to the shutdown of the Sundance 1 and 2 units and higher coal costs. US coal improved by $15 million over 2017 due to lower purchased power costs and better rail costs. Canadian Gas returned to normal cash flow levels as 2017 recorded a one time adjustment of $17 million (our share, net of non-controlling interests) due to a payment from the OEFC for prior periods. Hydro's cash flow was up by $4 million due primarily to stronger pricing of ancillary services. Energy Marketing's cashflows were $23 million below 2017 due to the settlement in the quarter, of contracts with unrealized losses at Dec. 31, 2017. Overall, after accounting for the OEFC payment in 2017 and the Sundance B and C termination payment in 2018, cash flows from the businesses were $4 million higher during the first quarter of 2018 compared to 2017.

Significant Events

Our strategic focus continues to be reducing our corporate debt, improving our operating performance, and progressing our transition to clean power generation. We made the following progress throughout the period:

- On Feb. 2, 2018, TransAlta Renewables entered into an arrangement to acquire two construction-ready wind projects in the Northeast United States. The wind development projects consist of: (i) a 90 Megawatt ("MW") project located in Pennsylvania which has a 15-year PPA and (ii) a 29 MW project located in New Hampshire with two 20-year PPAs (the "US Wind Projects"). All three counterparties have Standard & Poor's credit ratings of A+ or better. See the Significant and Subsequent Events section of this MD&A for further details.
- On March 15, 2018, we early redeemed our 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 were funded by cash on hand and our credit facility. See the Significant and Subsequent Events section of this MD&A for further details.
- During the quarter, we purchased and cancelled 374,900 Common Shares at an average price of $6.97 per Common Share through our NCIB program. See the Significant and Subsequent Events section of this MD&A for further details.
- On March 31, 2018, we received approximately $157 million in compensation for the termination of the Sundance B and C PPAs from the Balancing Pool. See the Significant and Subsequent Events section of this MD&A for further details.
- We permanently shutdown Sundance Unit 1 and mothballed Sundance Unit 2 on Jan. 1, 2018. We mothballed Sundance Unit 3 and Sundance Unit 5 on April 1, 2018.
- Donald Tremblay, Chief Financial Officer ("CFO") has chosen to leave the Corporation effective May 9, 2018 and will be returning to eastern Canada to be closer to his family. TransAlta has commenced a recruitment process for a new CFO. Brett Gellner, Chief Investment Officer, will act as Interim CFO, in addition to his current role, during the interim period.

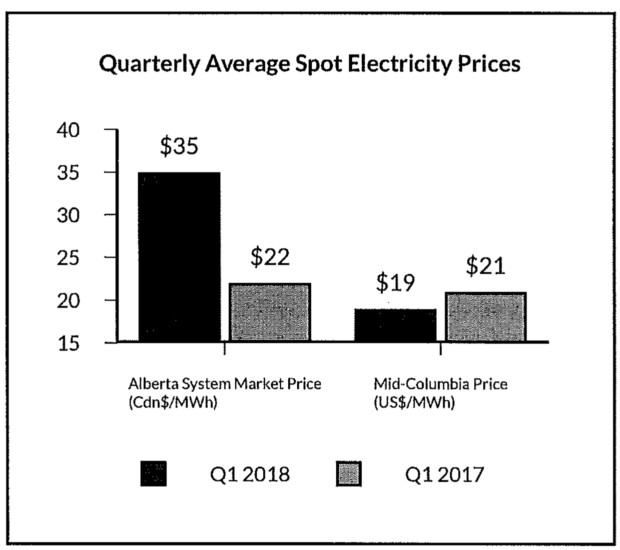
Adjusted Availability and Production

Adjusted availability for the three months ended March 31, 2018 was 93.9 per cent compared to 88.5 per cent for the same period in 2017. Canadian Coal, US Coal, and Australian Gas were all up compared to last year. Lower unplanned outages at Canadian and US Coal were the main cause of the increase in those segments.

Production for the three months ended March 31, 2018 was 7,171 gigawatt hours ("GWh"), compared to 9,051 GWh for the same period in 2017, mainly due to lower production at Canadian Coal due to higher paid curtailments on contracted assets, the retirement of Sundance Unit 1, and mothballing of Sundance Unit 2.

Electricity Prices

The average spot electricity prices in Alberta for the three months ended March 31, 2018 increased approximately 60 per cent compared to 2017 due to higher environmental levies and compliance costs which have increased the marginal cost to producers and tighter supply in the market. Natural gas prices were lower in the Pacific Northwest compared to last year and there were lower electricity loads due to warmer temperatures, which depressed electricity prices in the Pacific Northwest.



Discussion of Consolidated Financial Results

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures 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 on the performance of our business:

(i) Certain assets we own in Canada and 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;

(ii) 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;

(iii) 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 receive fixed monthly payments until Dec. 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 record the payments we receive as revenues as a proxy for operating income, and continue to depreciate the facility until Dec. 31, 2018; and

(iv) On commissioning the South Hedland Power Station, 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:

3 months ended March 31	2018	2017[1]
Net earnings attributable to common shareholders	**65**	—
Net earnings attributable to non-controlling interests	**28**	32
Preferred share dividends	**10**	—
Net earnings (loss)	**103**	32
Adjustments to reconcile net income to comparable EBITDA		
Depreciation and amortization	**130**	143
Foreign exchange loss	**2**	1
Net interest expense	**68**	62
Income tax expense (recovery)	**37**	(17)
Comparable reclassifications		
Decrease in finance lease receivables	**15**	15
Mine depreciation included in fuel cost	**31**	17
Australian interest income	**1**	—
Adjustments to earnings to arrive at comparable EBITDA		
Impacts associated with Mississauga recontracting[2]	**29**	21
Comparable EBITDA	**416**	274

(1) During the fourth quarter of 2017, we revised the way in which comparable EBITDA is reconciled to net earnings. Accordingly, 2017 results have been revised.
(2) Impacts associated with Mississauga recontracting for the three months ended March 31, 2018, are as follows: revenue $29 million (2017 - $27 million), fuel and purchased power and de-designated hedges nil (2017 - $4 million), and operations, maintenance, and administration nil (2017 - $2 million).

Net earnings and comparable EBITDA for the first quarter of 2018 include the $157 million ($115 million after-tax) Sundance B and C PPAs early termination payment from the Balancing Pool. Last year's net earnings and comparable EBITDA included the $34 million settlement with the OEFC ($12 million after-tax and non-controlling interests).

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.

3 months ended March 31	2018	2017
Cash flow from operating activities	425	281
Change in non-cash operating working capital balances	(123)	(95)
Cash flow from operations before changes in working capital	302	186
Adjustment:		
Decrease in finance lease receivable	15	15
Other	1	1
FFO	318	202
Deduct:		
Sustaining capital	(24)	(46)
Productivity capital	(4)	(2)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(41)	(47)
Other	(1)	(1)
FCF	238	96
Weighted average number of common shares outstanding in the year	288	288
FFO per share	1.10	0.70
FCF per share	0.83	0.33

The increase in FCF was driven primarily by the Sundance B and C termination payment of $157 million and lower sustaining capital expenditures.

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

3 months ended March 31	2018	2017
Comparable EBITDA	416	274
Interest expense	(53)	(55)
Provisions	5	1
Unrealized gains (losses) from risk management activities	(31)	5
Current income tax expense	(9)	(6)
Realized foreign exchange gain (loss)	3	1
Decommissioning and restoration costs settled	(7)	(4)
Other cash and non-cash items	(6)	(14)
FFO	318	202
Deduct:		
Sustaining capital	(24)	(46)
Productivity capital	(4)	(2)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(41)	(47)
Other	(1)	(1)
FCF	238	96

Segmented Comparable Results

Canadian Coal

3 months ended March 31	2018	2017
Availability (%)	90.5	83.7
Contract production (GWh)	3,300	4,971
Merchant production (GWh)	909	1,003
Total production (GWh)	4,209	5,974
Gross installed capacity (MW)[1]	3,231	3,791
Revenues	269	250
Fuel and purchased power	165	122
Comparable gross margin	104	128
Operations, maintenance, and administration	47	44
Taxes, other than income taxes	3	3
Net other operating income	(168)	(10)
Comparable EBITDA	222	91
Deduct:		
Sustaining capital:		
Routine capital	4	5
Mine capital	2	3
Finance leases	3	4
Planned major maintenance	—	17
Total sustaining capital expenditures	9	29
Productivity capital	1	1
Total sustaining and productivity capital expenditures	10	30
Provisions	(3)	(1)
Unrealized gains (losses) on risk management activities	1	4
Decommissioning and restoration costs settled	6	2
Canadian Coal cash flow	208	56

(1) On Jan. 1, 2018, 560 MW Sundance Units 1 and 2 were shut down and mothballed, respectively.

Availability for the first quarter of 2018 improved compared to 2017 mainly due to no planned outages in the quarter compared to one planned outage in first quarter of 2017 relating to our Sundance Unit 6 and much lower levels of unplanned outages.

Production for the three months ended March 31, 2018 decreased 1,765 GWh compared to 2017, despite higher availability, due to the retirement of Sundance Unit 1 and the mothballing of Sundance Unit 2 as well as higher paid curtailments on units under PPAs.

Revenues and Fuel and purchased power both increased due to higher environmental compliance costs, which are mostly passed through to the PPA customer and higher mining costs. In both cases this was expected. The increase in revenues was due to higher pass through and the higher Alberta power prices due to increased environmental compliance costs.

Comparable EBITDA for the three months ended March 31, 2018 excluding the Sundance B and C PPA termination payment decreased $26 million compared to 2017. Gross margin was negatively impacted by the scheduled termination of the Sundance A PPA. The reduction of overall capacity due to the retirement of Sundance Unit 1 and the mothballing of Sundance Unit 2 and higher coal costs.

For the first quarter of 2018, sustaining and productivity capital expenditures decreased by $20 million compared to 2017, mainly due to lower planned outage expenditures. In 2017, one planned outage was performed on Sundance Unit 6, while during the first quarter of 2018 there were no planned major outages.

US Coal

3 months ended March 31	2018	2017
Availability (%)	**99.7**	54.7
Adjusted availability (%)(1)	**99.7**	86.7
Contract sales (GWh)	**821**	905
Merchant sales (GWh)	**749**	959
Purchased power (GWh)	**(852)**	(1,052)
Total production (GWh)	**718**	812
Gross installed capacity (MW)	**1,340**	1,340
Revenues	**87**	88
Fuel and purchased power	**44**	64
Comparable gross margin	**43**	24
Operations, maintenance, and administration	**15**	13
Taxes, other than income taxes	**1**	1
Comparable EBITDA	**27**	10
Deduct:		
Sustaining capital:		
Finance leases	**1**	1
Planned major maintenance	**5**	5
Total sustaining capital expenditures	**6**	6
Productivity capital	**—**	1
Total sustaining and productivity capital expenditures	**6**	7
Unrealized gains (losses) on risk management activities	**2**	(2)
Decommissioning and restoration costs settled	**1**	2
US Coal cash flow	**18**	3

(1) Adjusted for economic dispatching.

Availability for the three months ended March 31, 2018 was up compared to 2017 as last year's performance was impacted by the forced outage on Unit 1 in January. In 2017 and 2018, both Units 1 and 2 commenced economic dispatching in February as a result of seasonally lower prices in the Pacific Northwest. This impacted our production for the quarter.

Contract sales are down compared to last year due to a 32 MW contract that ended in 2017.

Comparable EBITDA increased by $17 million compared to 2017, mainly due to purchasing power at lower power prices to fulfill our contract and hedge obligations and favourable impacts of mark-to-market on certain forward financial contracts that do not qualify for hedge accounting. Also positively impacting our comparable EBITDA is the reduction of our coal costs following renegotiation of our railway contracts with suppliers. Part of our fuel cost is now linked to natural gas prices, making the plant more competitive in a lower priced environment.

Canadian Gas

3 months ended March 31	2018	2017
Availability (%)	**98.7**	100.0
Contract production (GWh)	**414**	393
Merchant production (GWh)	**39**	44
Total production (GWh)	**453**	437
Gross installed capacity (MW)	**953**	953
Revenues	**108**	146
Fuel and purchased power	**29**	43
Comparable gross margin	**79**	103
Operations, maintenance, and administration	**13**	14
Taxes, other than income taxes	**1**	1
Comparable EBITDA	**65**	88
Deduct:		
Sustaining capital:		
Routine capital	**1**	—
Planned major maintenance	**1**	3
Total sustaining capital expenditures	**2**	3
Productivity capital	**1**	—
Total sustaining and productivity capital expenditures	**3**	3
Provisions	**(2)**	1
Unrealized gains (losses) on risk management activities	**4**	1
Canadian Gas cash flow	**60**	83

Availability was down this quarter due to unplanned outages at Ottawa and seasonal and equipment derates at Sarnia.

Production for the first quarter of 2018 increased 16 GWh compared to 2017, mainly due to increased contract production at Fort Saskatchewan due to higher customer demand, partially offset by lower merchant production at Sarnia due to market conditions.

Comparable EBITDA for the first quarter of 2018 decreased by $23 million compared to 2017 despite the positive impact from the Mississauga recontracting and cost reduction initiatives, offset by the retroactive contract indexation dispute settlement received in 2017 ($34 million). The Mississauga, Ottawa, Windsor, and our 60 per cent share of Fort Saskatchewan, generating facilities are owned through our 51 per cent interest in TA Cogen.

Australian Gas

3 months ended March 31	2018	2017
Availability (%)	**91.7**	89.9
Contract production (GWh)	**440**	398
Gross installed capacity (MW)	**450**	425
Revenues	**41**	40
Fuel and purchased power	**1**	2
Comparable gross margin	**40**	38
Operations, maintenance, and administration	**9**	7
Comparable EBITDA	**31**	31
Deduct:		
Sustaining capital:		
Planned major maintenance	**—**	1
Australian Gas cash flow	**31**	30

Production for the first quarter of 2018 increased 42 GWh compared to 2017, due mostly to the commissioning of the South Hedland Power Station in July 2017, offset by the termination of the Solomon Power Station contract. Our contracts in Australia are capacity contracts, and our results are not directly impacted by generation.

Comparable EBITDA for the three months ended March 31, 2018 was in line with the same period in 2017. Gross margin from South Hedland was largely offset by the loss of gross margin from the Solomon Power Station contract.

Wind and Solar

3 months ended March 31	**2018**	2017
Availability (%)	**94.5**	96.4
Contract production (GWh)	**749**	742
Merchant production (GWh)	**279**	313
Total production (GWh)	**1,028**	1,055
Gross installed capacity (MW)	**1,363**	1,363
Revenues	**86**	87
Fuel and purchased power	**6**	5
Comparable gross margin	**80**	82
Operations, maintenance, and administration	**13**	12
Taxes, other than income taxes	**2**	2
Comparable EBITDA	**65**	68
Deduct:		
Sustaining capital:		
Planned major maintenance	**3**	3
Unrealized gains (losses) on risk management activities	**(3)**	—
Wind and Solar cash flow	**65**	65

Production for the first quarter of 2018 decreased by 27 GWh compared to 2017, mainly due to the sale of the Wintering Hills merchant facility on March 1, 2017. Wind generation in eastern Canada and in the US was in line with last year.

Comparable EBITDA for the first quarter of 2018 was down $3 million compared to 2017 mainly due to unrealized mark-to-market losses recognized this period.

Hydro

3 months ended March 31	2018	2017
Contract production (GWh)	318	367
Merchant production (GWh)	5	8
Total production (GWh)	323	375
Gross installed capacity (MW)	926	926
Revenues	27	24
Fuel and purchased power	1	1
Comparable gross margin	26	23
Operations, maintenance, and administration	8	8
Taxes, other than income taxes	1	1
Comparable EBITDA	17	14
Deduct:		
Sustaining capital:		
Routine capital	—	1
Planned major maintenance	1	1
Total sustaining capital expenditures	1	2
Hydro cash flow	16	12

Production for the first quarter of 2018 decreased by 52 GWh compared to 2017, primarily due to lower water resources.

Comparable EBITDA for the first quarter of 2018 increased by $3 million compared to 2017, primarily due to increase in revenues from higher pricing of Ancillary Services, which more than offset the lower generation.

Energy Marketing

3 months ended March 31	2018	2017
Revenues and gross margin	17	1
Operations, maintenance, and administration	8	5
Comparable EBITDA	9	(4)
Deduct:		
Provisions	—	(1)
Unrealized gains (losses) on risk management activities	27	(8)
Energy Marketing cash flow	(18)	5

For the three months ended March 31, 2018, comparable EBITDA returned to a normal level and increased by $13 million compared to last year. Cashflows were $23 million below 2017 due to the settlement in the quarter, of contracts with unrealized losses at Dec. 31, 2017.

Corporate

Our Corporate overhead costs of $20 million were $4 million lower in the first quarter of 2018 compared to 2017 due to lower incentive payments.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit ratings 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 are focused on strengthening our financial position and flexibility and aim to meet all our target ranges by 2018.

FFO Before Interest to Adjusted Interest Coverage

As at	March 31, 2018[1]	Dec. 31, 2017
FFO	**920**	804
Less: Early termination payment received on Sundance B and C PPAs	**(157)**	—
Add: Interest on debt and finance leases, net of interest income and capitalized interest	**203**	205
FFO before interest	**966**	1,009
Interest on debt and finance leases, net of interest income	**209**	214
Add: 50 per cent of dividends paid on preferred shares	**20**	20
Adjusted interest	**229**	234
FFO before interest to adjusted interest coverage (times)	**4.2**	4.3

(1) Last 12 months. Our target range for FFO in 2018 is $775 million to $850 million. See the 2018 Financial Outlook for further details.

The ratio was comparable to 2017. Our target for FFO before interest to adjusted interest coverage is four to five times, and we expect this metric to improve as we execute on our deleveraging plan.

Adjusted Funds from Operations to Adjusted Net Debt

As at	March 31, 2018	Dec. 31, 2017
FFO[1,2]	**920**	804
Less: Early termination payment received on Sundance B and C PPAs	**(157)**	—
Less: 50 per cent of dividends paid on preferred shares	**(20)**	(20)
Adjusted FFO	**743**	784
Period-end long-term debt[3]	**3,411**	3,707
Less: Cash and cash equivalents	**(329)**	(314)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[4]	**(1)**	(30)
Adjusted net debt	**3,552**	3,834
Adjusted FFO to adjusted net debt (%)	**20.9**	20.4

(1) Last 12 months.
(2) Our target range for FFO in 2018 is $750 million to $800 million. See the 2018 Financial Outlook for further details.
(3) Includes finance lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at March 31, 2018 and Dec. 31, 2017.

Our adjusted FFO to adjusted net debt was comparable to 2017. We expect this metric to improve towards our targeted level of 20 to 25 per cent as we execute on our deleveraging plan.

Adjusted Net Debt to Comparable EBITDA

As at	March 31, 2018	Dec. 31, 2017
Period-end long-term debt[1]	**3,411**	3,707
Less: Cash and cash equivalents	**(329)**	(314)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[2]	**(1)**	(30)
Adjusted net debt	**3,552**	3,834
Comparable EBITDA[3]	**1,204**	1,062
Less: Early termination payment received on Sundance B and C PPAs	**(157)**	—
Adjusted comparable EBITDA	**1,047**	1,062
Adjusted net debt to comparable EBITDA (times)	**3.4**	3.6

(1) Includes finance lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at March 31, 2018 and Dec. 31, 2017.
(3) Last 12 months.

Our adjusted net debt to comparable EBITDA ratio improved compared to 2017, mainly due to the significant reduction in our net debt during the quarter. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times.

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 on one of the two projects has started. The two projects are fully contracted with credit worthy counterparties. See the Significant and Subsequent Events section of this MD&A for further details.

Kent Hills Wind Project
During 2017, TransAlta Renewables entered into a long-term contract with the 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 wind project. The additional 17.25 MW at Kent Hills is an expansion of our existing Kent Hills wind farms, increasing the total operating capacity of the Kent Hills wind farms to approximately 167 MW. We expect to begin the construction during the second quarter of 2018.

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 focus 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.

We are currently working to secure a path that will advance our investment in the project and secure a long-term contract for the project. The Brazeau Hydro Pumped Storage project is expected to have new capacity ranging between 400 MW to 900 MW, bringing the total Brazeau facility to 755 to 1,255 MW, post-completion. We estimate an investment in the range of $1.5 billion to $2.7 billion and expect construction to begin upon receipt of a long-term contract and regulatory approvals, between 2020 and 2021, with operations to commence in 2025. During the first quarter of 2018, we invested approximately $1 million to advance the environmental study, work with stakeholders and execute geotechnical work to help further our design and construction phase.

Project Greenlight
Our transformation project is a top priority for us. Driven by engagement from all employees, the intent is to deliver ambitious improvements in every part of the Corporation. Initiatives include increasing revenue, improving generation, reducing operating and maintenance costs, reducing overhead costs and financing costs, and optimizing our capital spend. We expect Project Greenlight to deliver sustainable pre-tax savings of approximately $50 million to $70 million annually, in 2018. We are on track to achieve our expected annual savings targets. During the first quarter of 2018, we invested approximately $11 million in this program, the cost of the program was largely offset by the cost reductions and productivity gains. We expect to invest a further $9 million on this program throughout 2018 and also expect to spend $20 million to $30 million related to productivity capital in 2018.

The following table outlines our generation comparable OM&A, including greenlight costs:

3 months ended March 31	**2018**	2017
Generation comparable OM&A	**105**	98
Greenlight transformation costs included in OM&A		
Canadian Coal	**(4)**	—
US Coal	**(1)**	—
Gas and Renewables	**(3)**	—
Adjusted generation comparable OM&A	**97**	98

Significant and Subsequent Events

A. TSX Acceptance of Normal Course Issuer Bid
In February we announced our intention to buy back 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 through a NCIB. 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 Company'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 first quarter of 2018, the Corporation purchased 374,900 Common Shares at an average price of $6.97 per Common Share. See Note 13 of the condensed consolidated financial statements for further details.

Further transactions 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.

The NCIB provides us with a capital allocation alternative with a view to long-term shareholder value. We believe the market price of TransAlta's Common Shares does not reflect the underlying value and purchases of Common Shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

B. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US Senior Notes due May 15, 2018. The Redemption price for the Notes was approximately $617 million (US$516 million), including $14 million of accrued interest. An early redemption premium was recognized in net interest expense for the three months ended March 31, 2018.

C. Balancing Pool Terminates the Alberta Sundance Power Purchase Arrangements

On Sept. 18, 2017, we 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 we took steps to re-take dispatch control for the units effective March 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid us approximately $157 million on March 29, 2018. We are disputing the termination payment received. The Balancing Pool excluded certain mining assets that we believe should be included in the net book value calculation for an additional $56 million, which is now subject to the PPA arbitration process.

D. 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, and (ii) a 29 MW project located in New Hampshire with two 20-year PPAs. All three counterparties 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 ("US HoldCo") acquired the 90 MW project on Feb. 20, 2018 whereas the acquisition of the 29 MW project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

On April 20, 2018, TransAlta Renewables acquired an economic interest in the US wind projects from the subsidiary of TransAlta ("TA Power") pursuant to the arrangement entered into with TransAlta on Feb. 20, 2018. Pursuant to the arrangement, US HoldCo will own the US wind projects directly and TA Power will issue to TransAlta Renewables preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US wind projects. The remaining construction and acquisition costs of the two US wind projects are to be funded by TransAlta Renewables 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 will subscribe for interest bearing notes issued by US HoldCo. The proceeds from the issuance of such preferred shares or notes shall be used exclusively in connection with the acquisition and construction of the US wind projects. TransAlta Renewables will fund these acquisition and construction costs using its existing liquidity and tax equity.

E. Management Change

The Corporation hosted its Annual General Meeting on April 20, 2018, during which it was announced that Donald Tremblay, CFO, has chosen to leave the Corporation, effective May 9, 2018, and will be returning to eastern Canada to be closer to his family. The Corporation has commenced a recruitment process for a new CFO. Brett Gellner, Chief Investment Officer, will act as Interim CFO, in addition to his current role, during the interim period.

Regulatory Updates

Refer to the Regional Regulation and Compliance discussion in our 2017 annual MD&A for further details that supplement the recent developments as discussed below:

Canadian Federal Government

On Feb. 17, 2018, the Department of Environment and Climate Change Canada published the draft regulations for gas-fired electricity generation, which include specific rules for coal-to-gas converted units. Under the proposed regulations, TransAlta's units are expected to receive an additional 75 years of operating life. Consultation on the draft regulations is expected to conclude in mid-2018 with finalized regulations expected by the end of 2018.

Alberta

On Jan. 1, 2018, the Alberta government transitioned from Specified Gas Emitters Regulation ("SGER") to the Carbon Competitiveness Incentive Regulation ("CCIR"). Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product/sectoral performance compliance standard. The carbon price remains set at $30/tCO_2e$ from 2018 to 2020 after which it is currently expected to follow the federal price increase to $40/tCO_2e$ in 2021 and $50/tCO_2e$ in 2022. The electricity sector performance standard was set at $0.37tCO_2e$/MWh 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 renewable assets that did not receive credits under SGER will now be able to opt into the CCIR and get carbon crediting up to the electricity sector performance standard in perpetuity. Once the wind projects crediting standard under SGER ends, these renewable projects will also be able to opt into the CCIR and receive crediting.

Capital Structure and Liquidity

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

	March 31, 2018		Dec. 31, 2017	
As at	**$**	**%**	$	%
TransAlta Corporation				
Recourse debt - CAD debentures	**1,047**	**14**	1,046	14
Recourse debt - US senior notes	**891**	**12**	1,499	19
Credit facilities	**325**	**4**	—	—
US tax equity financing	**30**	**—**	31	—
Other	**42**	**1**	13	—
Less: cash and cash equivalents	**(270)**	**(4)**	(294)	(4)
Less: fair value asset of economic hedging instruments on debt	**(1)**	**—**	(30)	—
Net recourse debt	**2,064**	**27**	2,265	29
Non-recourse debt	**197**	**3**	208	3
Finance lease obligations	**66**	**1**	69	1
Total net debt - TransAlta Corporation	**2,327**	**31**	2,542	33
TransAlta Renewables				
Credit facility	**—**	**—**	27	—
Less: cash and cash equivalents	**(59)**	**(1)**	(20)	—
Net recourse debt	**(59)**	**(1)**	7	—
Non-recourse debt	**813**	**11**	814	11
Total net debt - TransAlta Renewables	**754**	**10**	821	11
Total consolidated net debt	**3,081**	**41**	3,363	44
Non-controlling interests	**1,048**	**14**	1,059	14
Equity attributable to shareholders				
Common shares	**3,090**	**41**	3,094	40
Preferred shares	**942**	**13**	942	12
Contributed surplus, deficit, and accumulated other comprehensive income	**(661)**	**(9)**	(710)	(9)
Total capital	**7,500**	**100**	7,748	100

During the quarter we reduced our corporate debt by approximately $600 million and enhanced shareholder value by:

- 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.
- purchased and cancelled 374,900 Common Shares at an average price of $6.97 under our NCIB program. We believe the market price of TransAlta's Common Shares does not reflect the underlying value and purchases of Common Shares for cancellation under the NCIB provides an opportunity to enhance shareholder value. See the Significant and Subsequent Events section of this MD&A for further details.

Overall, our net debt was reduced by close to $300 million during the quarter.

During 2019 to 2020, we have approximately $941 million of debt maturing. We expect to refinance some of these upcoming debt maturities by raising $300 to $400 million of debt secured by our contracted cash flows. We also expect to continue our deleveraging strategy as a significant part of our free cash flow over the three years will be allocated to debt reduction.

Our credit facilities provide us with significant liquidity. We have a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, comprised of our $1.0 billion committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $500 million (Dec. 31, 2017 - $500 million) and our US$200 million and $240 million committed bilateral facilities. These facilities expire in 2021, 2021, 2020, and 2019 respectively. The $1.5 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.

In total, $1.1 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At March 31, 2018, the $0.9 billion (Dec. 31, 2017 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (Dec. 31, 2017 - nil) and letters of credit of $0.6 billion (Dec. 31, 2017 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.1 billion available under the credit facilities, the Corporation also has $329 million of available cash and cash equivalents.

The Corporation's subsidiaries have issued non-recourse bonds of $1,010 million (Dec. 31, 2017 - $1,021 million) that are subject to customary financing conditions and covenants that may restrict our 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 first quarter. However, funds in these entities that have accumulated since the first quarter test will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2018. At March 31, 2018, $53 million (Dec. 31, 2017 -$35 million) of cash was subject to these financial restrictions. In addition, we have $31 million of resctricted cash related to the Kent Hills project financing that are being held in a construction reserve account, which will be released upon certain conditions, including commissioning, being met.

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. We have elected to use letters of credit as at March 31, 2018. However, as at March 31, 2018, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letters of credit and was not available for general use.

The strengthening of the US dollar has increased our long-term debt balances by $21 million in 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	March 31, 2018	December 31,
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**18**	(61)
Foreign currency economic cash flow hedges on debt	**3**	(45)
Economic hedges and other	**—**	(7)
Total	**21**	(113)

Share Capital

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

As at	May 7, 2018	March 31, 2018	December 31,
		Number of shares *(millions)*	
Common shares issued and outstanding, end of period	**287.5**	**287.9**	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 March 31, 2018, we own 64.0 per cent (Dec. 31, 2017 - 64.0 per cent) of TransAlta Renewables. 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 TransAlta Cogeneration L.P ("TA Cogen"), which owns, operates, or has an interest in four natural-gas-fired facilities (Mississauga, Ottawa, Windsor, and Fort Saskatchewan) and one coal-fired generating facility.

Reported earnings attributable to non-controlling interests for the first quarter of 2018 decreased to $28 million from $32 million in the first quarter of 2017, due to the settlement in 2017 of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor facilities, partially offset by higher earnings at TransAlta Renewables resulting from a favourable reduction in unrealized foreign exchange losses on some of its financial interests in the Australian Assets.

Returns to Providers of Capital
Net Interest Expense
The components of net interest expense are shown below:

Three months ended March 31	**2018**	2017
Interest on debt	**53**	56
Interest income	**(3)**	(1)
Capitalized interest	**—**	(3)
Loss on early redemption of US Senior Notes	**5**	—
Interest on finance lease obligations	**1**	1
Credit facility and bank charges	**3**	4
Other interest	**3**	—
Accretion of provisions	**6**	5
Net interest expense	**68**	62

Net interest expense was higher period-over-period due to the $5 million pre-payment premium relating to the early redemption of the US $500 million Senior Notes.

Dividends to Shareholders
On April 19, 2018, we declared a quarterly dividend of$0.04 per common share, payable on July 3, 2018. We also declared a quarterly dividend of$0.16931 on the Series A preferred shares, $0.19951 on the Series B preferred shares, $0.25169 on the Series C preferred shares, $0.32463 on the Series E preferred shares, and $0.33125 on the Series G preferred shares, all payable on July 3, 2018.

The following are the common and preferred shares dividends declared in the first quarter of 2018:

	Common	**Preferred Series dividends per share**				
Declaration date	**dividends per share**	**A**	**B**	**C**	**E**	**G**
Feb. 2, 2018	0.04	0.1693	0.17889	0.2517	0.3246	0.33125

Financial Position

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

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	15	Timing of receipts and payments
Trade and other receivables	(262)	Timing of customer receipts and seasonality of revenue
Property, plant, and equipment, net	(109)	Depreciation for the period ($147 million), partially offset by favourable changes in foreign exchange rates ($23 million), and additions ($23 million)
Risk management assets (current and long term)	(27)	Contract settlements, partially offset by favourable changes in foreign exchange rates, favourable changes in market price movements, and new contracts
Other assets	37	Project development costs related to the acquisition of two US Wind projects
Others	5	
Total decrease in assets	**(341)**	

Liabilities and equity	Increase/ (decrease	Primary factors explaining change
Accounts payable and accrued liabilities	(99)	Timing of payments and accruals
Credit facilities, long term debt, and finance lease obligations (including current portion)	(296)	Repayment of long-term debt ($660 million), partially offset by draw dawn on credit facility ($298 million), and unfavourable foreign exchange rate ($21 million)
Deferred income tax liabilities	19	Increase in taxable temporary differences
Risk management liabilities (current and long term)	(12)	Contract settlements, partially offset by favourable changes in foreign exchange rates, favourable changes in market price movements, and new contracts
Equity attributable to shareholders	45	Net earnings ($75 million), partially offset by common and preferred share dividends ($21 million), and the impact of changes in our accounting policies ($14 million)
Others	2	
Total decrease in liabilities and equity	**(341)**	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2018, compared to the same period March 31, 2017:

3 months ended March 31	2018	2017	Primary factors explaining change
Cash and cash equivalents, beginning of period	**314**	305	
Provided by (used in):			
Operating activities	**425**	281	Higher cash earnings ($116 million) and favourable change in non-cash working capital ($28 million)
Investing activities	**(53)**	5	Lower proceeds on disposals ($60 million) and higher project development acquisitions ($36 million)
Financing activities	**(357)**	(88)	Increase in repayment of long-term debt ($646 million), partially offset by increase in borrowings under credit facilities ($326 million) and realized gains on financial instruments ($50 million)
Translation of foreign currency cash	**—**	1	
Cash and cash equivalents, end of period	**329**	504	

Other Consolidated Analysis

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 March 31, 2018, we provided letters of credit totalling $639 million (Dec. 31, 2017 - $677 million) and cash collateral of $51 million (Dec. 31, 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.

Contingencies

I. Line Loss Rule Proceeding

TransAlta has been participating in a line loss rule proceeding (the "LLRP") 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 potential retroactive exposure faced by TransAlta for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if TransAlta and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil; TransAlta accordingly recorded an appropriate provision in 2017.

II. FMG Disputes

The Corporation is currently engaged in two pieces of litigation 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 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. The Corporation is disputing the termination payment it received. The Balancing Pool excludes certain mining assets that the Corporation believes should be included in the net book value calculation for an additional $56 million, which is subject to the PPA arbitration process.

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2017 Annual Integrated Report and Note 8 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2018 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2017 Annual Integrated Report and Note 9 of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Refer to the Accounting Changes section of this MD&A for further details on the adoption of IFRS 9 *Financial Instruments* effective Jan. 1, 2018. Our risk management profile and practices have not changed materially from Dec. 31, 2017.

We may enter into commodity transactions involving non-standard features for which observable market data is not available. These are defined under IFRS as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is, therefore, developed using valuation models based upon internally developed assumptions or inputs. Our Level III fair values are determined using data such as unit availability, transmission congestion, or demand profiles. Fair values are validated on a quarterly basis by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements.

As at March 31, 2018, total Level III financial instruments had a net asset carrying value of $725 million (Dec. 31, 2017 - $771 million net asset). The decrease during the period is primarily due to the settlement of contracts, market price changes in value of the long-term power sale contract designated as an all-in-one cash flow hedge for which changes in fair value are recognized in other comprehensive income, partially offset by favourable foreign exchange rates.

2018 Financial Outlook

The following table outlines our expectation on key financial targets for 2018:

Measure	Original Target	Revised Target
Comparable EBITDA	$950 million to $1,050 million	$1,000 million to $1,050 million
FFO	$725 million to $800 million	$750 million to $800 million
FCF	$275 million to $350 million	$300 million to $350 million
Canadian Coal capacity factor	65 to 75 per cent	Unchanged
Dividend	$0.16 per share annualized, 13 to 17 per cent payout of FCF	$0.16 per share annualized, 13 to 15 per cent payout of FCF

As a result of our strong performance during our first quarter, we revised our targets as outlined in the above table.

Operations

Availability

Total availability of our Canadian coal fleet is expected to be in the range of 87 to 89 per cent in 2018. Availability of our other generating assets (gas, renewables) is expected to be in the range of 95 per cent in 2018. We will be accelerating our transition to gas and renewables generation, and have retired Sundance Unit 1 effective Jan. 1, 2018, and temporarily mothballed Sundance Unit 2 effective Jan. 1, 2018 and Sundance Unit 3 and Sundance Unit 5 effective April 1, 2018.

Market Hedging Strategy

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 our cash fuel costs per tonne to be higher compared to 2017 due to lower produced volumes.

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. This should allow us to generate more electricity and increase profits.

Most of our generation from gas is sold under contract with pass-through provisions for fuel. For gas generation with no pass-through provision, 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

Comparable 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 2018 objective for Energy Marketing is for the segment to contribute between $70 million to $80 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.

We expect to spend approximately US$240 million to construct and commission the two US wind development projects. We anticipate using foreign exchange contracts to manage the foreign exchange exposure created by these projects. See the Significant and Subsequent Events section of this MD&A for further details.

Net Interest Expense

Net interest expense for 2018 is expected to be lower than in 2017 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.

Net Debt, Liquidity, and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.1 billion in liquidity, as well as more than $300 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 maturities in 2018 and 2019.

Growth Expenditures

Our growth 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		2018[2]	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
Kent Hills 3 Wind Expansion[3]	36	9	27	Q4 2018	17.25 MW expansion project on our existing Kent Hills wind farms
Pennsylvania wind development project[4]	164	30	111	Q3 2019	90 MW wind project with a 15-year PPA
New Hampshire wind development project[4, 5]	76	—	40	Q3 2019	29 MW wind project with two 20-year PPAs
Total					

(1) Represents amounts spent as of March 31, 2018.
(2) Remainder of year.
(3) Our 17 per cent partner on the existing Kent Hills facilities is participating in the expansion project and also owns a 17 per cent interest. They will be funding their share of the total project costs.
(4) Denominated in United States dollars. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.
(5) Project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

Sustaining and Productivity Capital Expenditures

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 to date[1]	Expected spend in 2018
Routine capital	Capital required to maintain our existing generating capacity	8	71 - 74
Planned major maintenance	Regularly scheduled major maintenance	10	71 - 74
Mine capital	Capital related to mining equipment and land purchases	2	32 - 34
Finance leases	Payments on finance leases	4	23 - 25
Total sustaining capital		**24**	**195 - 205**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	4	20 - 30
Total sustaining and productivity capital		**28**	**215 - 235**

Significant planned major outages for 2018 include the following:

- a major outage in our Canadian Coal segment during the fourth quarter to a unit operated by our partner;
- a major outage at our US Coal segment scheduled for the second quarter;
- a major outage in our Canadian Gas segment related to our Sarnia and Fort Saskatchewan facilities during the second quarter and fourth quarter, respectively; and
- distributed expenditures across our wind and hydro fleet.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2018:

	Canadian Coal	Gas and Renewables	Total	Lost to date
GWh lost	130 - 170	400 - 600	530 - 770	35

(1) As at March 31, 2018.

Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, existing liquidity, and capital raised from our contracted cash flows. We have access to approximately $1.1 billion in liquidity. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

Accounting Changes

A. Current Accounting Changes

I. IFRS 15 *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. Under this method, the comparative period presented in the condensed consolidated financial statements as at and for the three months ended March 31, 2017 will not be restated and is reported under IAS 18 *Revenue*. Instead, the Corporation recognized the cumulative impact of the initial application of the standard in Deficit as at Jan. 1, 2018, as follows: 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 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 requirements 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. This change had no impact on the cumulative impact of initial adoption as recognized in Deficit as Jan. 1, 2018.

Refer to Note 2 of the Corporation's condensed consolidated financial statements for a more detailed discussion of the Corporation's accounting policies under IFRS 15.

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

1) The classification and measurement of financial assets and liabilities
2) The recognition and measurement of impairment of financial assets
3) General hedge accounting

In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods.

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 through OCI. 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 from IAS 39. While the Corporation had no direct impact of adopting the IFRS 9 classification and measurement requirements, a $1 million increase in deficit resulted from the increase in equity attributable to non-controlling interests due to 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, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness. The 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.

Refer to Note 2 of the Corporation's condensed consolidated financial statements for a more detailed discussion of the Corporation's accounting policies under IFRS 9.

III. Change in Estimates - Useful Lives

As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(H) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the three months ended March 31, 2018 increased by approximately $10 million and the full year depreciation expense is expected to increase be approximately $38 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

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. Refer to Note 3 of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 16. The Corporation is in the process of completing an initial scoping assessment for IFRS 16 and have prepared a detailed project plan. The Corporation anticipates that most of the effort under the implementation plan will occur in mid-to-late 2018. It is not yet possibleto make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

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.

	Q2 2017	Q3 2017	Q4 2017	Q1 2018
Revenues	503	588	638	**588**
Comparable EBITDA	268	245	275	**416**
FFO	187	196	219	**318**
Net earnings (loss) attributable to common shareholders	(18)	(27)	(145)	**65**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.06)	(0.09)	(0.50)	**0.23**
	Q2 2016	**Q3 2016**	**Q4 2016**	**Q1 2017**
Revenues	492	620	717	578
Comparable EBITDA	248	243	374	274
FFO	175	163	228	202
Net earnings (loss) attributable to common shareholders	6	(12)	61	—
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.02	(0.04)	0.21	—

(1) Basic and diluted earnings per share attributable to common shares are calculated each period using the weighted average number of 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:

- recognition of the $157 million early termination payment received regarding Sundance PPAs during the first quarter of 2018;
- a recovery of a writedown of deferred tax assets in the first and second quarters of 2016, and the second quarter of 2017;
- change in income tax rates in US in the fourth quarter of 2017;
- effects of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first, second, and third quarters of 2016, and unrealized gains in the first quarter of 2017;
- effects of the Keephills 1 outage provision in the fourth quarter of 2016;
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016, and the Sundance Unit 1 impairment charge during the second quarter of 2017;
- effects of the Mississauga facility recontracting during the fourth quarter of 2016;
- 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.

TransAlta Corporation
Condensed Consolidated Statements of Earnings
(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2018**	2017
Revenues *(Note 4)*	**588**	578
Fuel and purchased power	**277**	250
Gross margin	**311**	328
Operations, maintenance, and administration	**133**	125
Depreciation and amortization	**130**	143
Taxes, other than income taxes	**8**	8
Net other operating income *(Note 5)*	**(168)**	(10)
Operating income	**208**	62
Finance lease income	**2**	16
Net interest expense *(Note 6)*	**(68)**	(62)
Foreign exchange loss	**(2)**	(1)
Earnings before income taxes	**140**	15
Income tax expense (recovery) *(Note 7)*	**37**	(17)
Net earnings	**103**	32
Net earnings attributable to:		
TransAlta shareholders	**75**	—
Non-controlling interests *(Note 8)*	**28**	32
	103	32
Net earnings attributable to TransAlta shareholders	**75**	—
Preferred share dividends *(Note 14)*	**10**	—
Net earnings attributable to common shareholders	**65**	—
Weighted average number of common shares outstanding in the year *(millions)*	**288**	288
Net earnings per share attributable to common shareholders, basic and diluted	**0.23**	—

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Comprehensive Income
(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2018**	2017
Net earnings	**103**	32
Other comprehensive income (loss)		
Net actuarial gains on defined benefit plans, net of tax[(1)]	**3**	1
Gains on derivatives designated as cash flow hedges, net of tax[(2)]	**1**	—
Total items that will not be reclassified subsequently to net earnings	**4**	1
Gains (losses) on translating net assets of foreign operations, net of tax[(3)]	**33**	(6)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(4)]	**(12)**	13
Gains on derivatives designated as cash flow hedges, net of tax[(5)]	**6**	29
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(6)]	**(23)**	(6)
Total items that will be reclassified subsequently to net earnings	**4**	30
Other comprehensive income	**8**	31
Total comprehensive income	**111**	63
Total comprehensive income attributable to:		
TransAlta shareholders	**82**	26
Non-controlling interests *(Note 8)*	**29**	37
	111	63

(1) Net of income tax expense of 1 for the three months ended March 31, 2018 (2017 - nil).
(2) Net of income tax expense of nil for the three months ended March 31, 2018 (2017 - nil).
(3) Net of income tax expense of nil for the three months ended March 31, 2018 (2017 - 1 recovery).
(4) Net of income tax recovery of 1 for the year ended March 31, 2018 (2017 - 1 expense).
(5) Net of income tax expense of 1 for three months ended March 31, 2018 (2017 - 22 expense).
(6) Net of reclassification of income tax expense of 7 for the three months ended March 31, 2018 (2017 - 11 expense).

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Financial Position
(in millions of Canadian dollars)

Unaudited	**March 31, 2018**	Dec. 31, 2017
Cash and cash equivalents	**329**	314
Trade and other receivables	**671**	933
Prepaid expenses	**33**	24
Risk management assets *(Notes 9 and 10)*	**194**	219
Inventory	**224**	219
	1,451	1,709
Restricted cash *(Note 12)*	**31**	30
Long-term portion of finance lease receivables	**209**	215
Property, plant, and equipment *(Note 11)*		
Cost	**13,028**	12,973
Accumulated depreciation	**(6,559)**	(6,395)
	6,469	6,578
Goodwill	**464**	463
Intangible assets	**358**	364
Deferred income tax assets	**25**	24
Risk management assets *(Notes 9 and 10)*	**682**	684
Other assets	**274**	237
Total assets	**9,963**	10,304
Accounts payable and accrued liabilities	**496**	595
Current portion of decommissioning and other provisions	**75**	67
Risk management liabilities *(Notes 9 and 10)*	**95**	101
Income taxes payable	**66**	64
Dividends payable *(Note 13)*	**34**	34
Current portion of long-term debt and finance lease obligations *(Note 12)*	**140**	747
	906	1,608
Credit facilities, long-term debt, and finance lease obligations *(Note 12)*	**3,271**	2,960
Decommissioning and other provisions	**398**	403
Deferred income tax liabilities	**568**	549
Risk management liabilities *(Notes 9 and 10)*	**34**	40
Defined benefit obligation and other long-term liabilities	**367**	359
Equity		
Common shares *(Note 13)*	**3,090**	3,094
Preferred shares *(Note 14)*	**942**	942
Contributed surplus	**11**	10
Deficit	**(1,168)**	(1,209)
Accumulated other comprehensive income	**496**	489
Equity attributable to shareholders	**3,371**	3,326
Non-controlling interests *(Note 8)*	**1,048**	1,059
Total equity	**4,419**	4,385
Total liabilities and equity	**9,963**	10,304

Commitments and contingencies *(Note 15)*

Subsequent events *(Note 3)*

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Changes in Equity
(in millions of Canadian dollars)

Unaudited *3 months ended March 31, 2018*	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec 31, 2017	3,094	942	10	(1,209)	489	3,326	1,059	4,385
Impact of changes in accounting policy *(Note 2)*	—	—	—	(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	—	—	—	75	—	75	28	103
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	21	21	—	21
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(16)	(16)	—	(16)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	3	3	—	3
Intercompany fair value through OCI investments	—	—	—	—	(1)	(1)	1	—
Total comprehensive income				75	7	82	29	111
Common share dividends	—	—	—	(11)	—	(11)	—	(11)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Shares purchased under NCIB *(Note 13)*	(4)	—	—	1	—	(3)	—	(3)
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests *(Note 8)*	—	—	—	—	—	—	(41)	(41)
Balance, Mar 31, 2018	**3,090**	**942**	**11**	**(1,168)**	**496**	**3,371**	**1,048**	**4,419**

See accompanying notes.

3 months ended March 31, 2017	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	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	—	—	—	—	—	—	32	32
Other comprehensive income								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	7	7	—	7
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	18	18	5	23
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	1	1	—	1
Total comprehensive income				—	26	26	37	63
Distributions paid, and payable, to non-controlling interests *(Note 8)*	—	—	—	—	—	—	(47)	(47)
Balance, Mar 31, 2017	3,094	942	9	(933)	425	3,537	1,142	4,679

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Cash Flows
(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2018**	2017
Operating activities		
Net earnings	**103**	32
Depreciation and amortization *(Note 16)*	**161**	160
Accretion of provisions *(Note 6)*	**6**	6
Decommissioning and restoration costs settled	**(7)**	(4)
Deferred income tax expense (recovery) *(Note 7)*	**28**	(23)
Unrealized (gain) loss from risk management activities	**(21)**	(5)
Unrealized foreign exchange loss	**10**	2
Provisions	**5**	—
Other non-cash items	**17**	18
Cash flow from operations before changes in working capital	**302**	186
Change in non-cash operating working capital balances	**123**	95
Cash flow from operating activities	**425**	281
Investing activities		
Additions to property, plant, and equipment *(Note 11)*	**(23)**	(60)
Additions to intangibles	**(5)**	(4)
Acquisition of renewable energy development projects *(Note 3)*	**(30)**	—
Proceeds on sale of property, plant, and equipment	**1**	—
Proceeds on sale of Wintering Hills facility	**—**	61
Decrease in finance lease receivable	**15**	15
Other	**1**	(2)
Change in non-cash investing working capital balances	**(12)**	(5)
Cash flow from (used in) investing activities	**(53)**	5
Financing activities		
Net increase in borrowings under credit facilities *(Note 12)*	**326**	—
Repayment of long-term debt *(Note 12)*	**(660)**	(14)
Dividends paid on common shares *(Note 13)*	**(12)**	(12)
Dividends paid on preferred shares *(Note 14)*	**(10)**	(10)
Funds paid to repurchase common shares under NCIB *(Note 13)*	**(1)**	—
Realized gains on financial instruments	**50**	—
Distributions paid to subsidiaries' non-controlling interests *(Note 8)*	**(41)**	(47)
Decrease in finance lease obligations *(Note 12)*	**(4)**	(4)
Other	**(5)**	(1)
Cash flow used in financing activities	**(357)**	(88)
Cash flow from operating, investing, and financing activities	**15**	198
Effect of translation on foreign currency cash	**—**	1
Increase in cash and cash equivalents	**15**	199
Cash and cash equivalents, beginning of period	**314**	305
Cash and cash equivalents, end of period	**329**	504
Cash income taxes paid	**12**	2
Cash interest paid	**37**	22

See accompanying notes.

Notes to Condensed Consolidated Financial Statements

(Unaudited)

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

1. Accounting Policies

A. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting* using the same accounting policies as those used in TransAlta Corporation's ("TransAlta" or the "Corporation") most recent annual consolidated financial statements, except as outlined in *Note 2(A)*. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Corporation's annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation's most recent annual consolidated financial statements which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

The unaudited interim condensed consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls.

The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments, which are stated at fair value.

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit and Risk Committee on behalf of the Board of Directors on May 7, 2018.

B. Use of Estimates and Significant Judgments

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Actual results could differ from these 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. Refer to Note 2(Z) of the Corporation's most recent annual consolidated financial statements and to Note 2 for information regarding judgments and estimates.

2. Significant Accounting Policies

A. Current Accounting Changes

I. IFRS 15 *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 not completed contracts at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to the Corporation's most recent annual report for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard in 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 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 requirements 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 below, and to Note 4 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 three months ended March 31, 2018.

Condensed Consolidated Statement of Earnings

Three months ended March 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Revenues	589	(1)	588
Fuel and purchased power	(279)	2	(277)
Net interest expense	(67)	(1)	(68)
Net earnings impact	103	—	103

Condensed Consolidated Statements of Financial Position

As at March 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Deferred income tax liabilities	572	(4)	568
Defined benefit obligation and other long-term liabilities (contract liability)	350	17	367
Deficit	(1,155)	13	(1,168)

There were no impacts to the statement of cash flows as a result of adopting IFRS 15.

i) Revenue from Contracts with Customers

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. The Corporation excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

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. 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 includes both variability in quantity and pricing. The consideration contained in some of the Corporation's contracts with customers is primarily variable. Variable consideration is assessed at each reporting period to determine whether the constraint is lifted.

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. Obligation 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 obligations 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 judgement in determining whether goods or services constitute distinct goods or services or a series of distinct goods 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 estimatded 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 make 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. Revenues associated with leases are recognized as outlined in Note 2(R) of the Corporation's most recent annual report.

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 condensed 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.

II. IFRS 9 *Financial Instruments*
Effective Jan. 1, 2018, the Corporation adopted IFRS 9, which introduces new requirements for:
1) The classification and measurement of financial assets and liabilities
2) The recognition and measurement of impairment of financial assets
3) 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 Deficit at Jan. 1, 2018. While the Corporation had no direct impact of adopting IFRS 9, a $1 million increase in 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 below. For more information on the Corporation's accounting policies under IAS 39 for the period ended March 31, 2017, refer to Note 2 of the Corporation's most recent 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 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 which 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.

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 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.

IFRS 9 permits a simplified approach for measuring the loss allowance for trade receivables, contract assets and lease receivables at an amount equal to lifetime expected credit losses under certain circumstances. The Corporation measures its trade receivables, contract assets recognized under IFRS 15 using the simplified approach. The Corporation uses the general approach to measure the expected credit loss for lease receivables.

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.

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 9 and 10.

The Corporation's risk management objective and strategy, including risk management instruments and their key terms, are detailed in Notes 9A and 9C.

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 other comprehensive income. 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 accumulated other comprehensive income.

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(H) of our most recent annual consolidated financial statements, the Corporation has adjusted the useful lives of some of its Sunhills mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power for the three months ended March 31, 2018 increased by approximately $10 million and the full year depreciation expense is expected to increase by approximately $38 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

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. Refer to Note 3 of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 16. The Corporation is in the process of completing an initial scoping assessment for IFRS 16 and has prepared a detailed project plan. The Corporation anticipates that most of the effort under the implementation plan will occur in mid-to-late 2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

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.

3. Significant Events

A. 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 ("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 Company'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 first quarter of 2018, the Corporation purchased and cancelled 374,900 Common Shares at an average price of $6.97 per Common Share. See Note 13 for further details.

Further transactions 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.

B. 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. See Note 12 for further details.

C. Balancing Pool Terminates 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 Power Purchase Arrangements ("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 excludes certain mining assets that the Corporation believes should be included in the net book value calculation for an additional $56 million, which is subject to the PPA arbitration process.

D. 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, and (ii) a 29 MW project located in New Hampshire with two 20-year PPAs. All three counterparties 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 ("US HoldCo") acquired the 90 MW project on Feb. 20, 2018, whereas the acquisition of the 29 MW project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

On April 20, 2018, TransAlta Renewables acquired an economic interest in the US wind projects from the subsidiary of TransAlta ("TA Power") pursuant to the arrangement entered into with TransAlta on Feb. 20, 2018. Pursuant to the arrangement, US HoldCo will own the US wind projects directly and TA Power will issue to TransAlta Renewables preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US wind projects. The remaining construction and acquisition costs of the two US wind projects are to be funded by TransAlta Renewables 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 will subscribe for interest bearing notes issued by US HoldCo. The proceeds from the issuance of such preferred shares or notes shall be used exclusively in connection with the acquisition and construction of the US wind projects. TransAlta Renewables will fund these acquisition and construction costs using its existing liquidity and tax equity.

The acquisition is accounted for as an asset acquisition, not as a business combination.

4. Revenue from Contracts with Customers

Disaggregation of Revenue from Contracts with Customers

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.

3 months ended March 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	204	2	56	23	65	24	–	–	374
Revenue from leases	17	–	–	17	8	1	–	–	43
Revenue from derivatives	11	64	6	–	(3)	–	17	–	95
Government incentives	–	–	–	–	5	–	–	–	5
Revenue from other(1)	37	21	–	1	11	2	–	(1)	71
Total Revenue	**269**	**87**	**62**	**41**	**86**	**27**	**17**	**(1)**	**588**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	10	2	–	–	4	–	–	–	16
Over time	194	–	56	23	61	24	–	–	358
Total Revenue	**204**	**2**	**56**	**23**	**65**	**24**	**–**	**–**	**374**

(1) Includes merchant revenue and other miscellaneous.

5. Net Other Operating Income

Net other operating (income) losses are comprised of the following:

3 months ended March 31	2018	2017
Alberta Off-Coal Agreement	(10)	(10)
Termination of Sundance B and C PPAs	(157)	—
Insurance recoveries	(1)	—
Net other operating income	**(168)**	(10)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta 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 receives annual cash payments on or before July 31 of approximately $40 million ($37.4 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, 2030.

B. Termination of Sundance B and C PPAs

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, and received $157 million during the first quarter of 2018. See Note 3 for further details.

6. Net Interest Expense

The components of net interest expense are as follows:

3 months ended March 31	2018	2017
Interest on debt	53	56
Interest income	(3)	(1)
Capitalized interest	—	(3)
Loss on early redemption of US Senior Notes *(Note 12)*	5	—
Interest on finance lease obligations	1	1
Credit facility fees and bank charges	3	4
Other interest	3	—
Accretion of provisions	6	5
Net interest expense	**68**	62

7. Income Taxes

The components of income tax expense are as follows:

3 months ended March 31	2018	2017
Current income tax expense	9	6
Deferred income tax expense related to the origination and reversal of temporary differences	24	(17)
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[1]	4	(6)
Income tax expense (recovery)	**37**	(17)

3 months ended March 31	2018	2017
Current income tax expense	9	6
Deferred income tax expense (recovery)	28	(23)
Income tax expense	**37**	(17)

(1) During the three months ended March 31, 2018 , the Corporation recorded a writedown of deferred income tax assets of $4 million (March 31, 2017 - $6 million reversal). The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. Recognized other comprehensive income during the period has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

8. Non-Controlling Interests

The Corporation's subsidiaries with significant non-controlling interests are TransAlta Renewables and TransAlta Cogeneration L.P. The net earnings, distributions, and equity attributable to TransAlta Renewables' non-controlling interests include the 17 per cent non-controlling interest in the Kent Hills Wind LP, which owns the 150 MW Kent Hills wind farm and the 17.25 MW Kent Hills 3 expansion project located in New Brunswick.

The Corporation's share of ownership and equity participation in TransAlta Renewables during the three months ended March 31, 2018 and 2017 is as follows:

Period	Ownership and voting rights percentage	Equity participation percentage[1]
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 and thereafter	64.0	64.0

(1) As the Class B shares issued to the Corporation in the sale of Australian assets were determined to constitute financial liabilities of TransAlta Renewables and did not participate in earnings until commissioning of the South Hedland facility, they were excluded from the allocation of equity and earnings until converted to common shares on Aug. 1, 2017.

Amounts attributable to non-controlling interests are as follows:

3 months ended March 31	2018	2017
Net earnings		
TransAlta Cogeneration L.P.	**3**	20
TransAlta Renewables	**25**	12
	28	32
Total comprehensive income		
TransAlta Cogeneration L.P.	**3**	19
TransAlta Renewables	**26**	18
	29	37
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**20**	26
TransAlta Renewables	**21**	21
	41	47

As at	March 31, 2018	Dec. 31, 2017
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**230**	247
TransAlta Renewables	**818**	812
	1,048	1,059
Non-controlling interests per share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**36.0**	36.0

9. Financial Instruments

A. Financial Assets and Liabilities – Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost.

B. Fair Value of Financial Instruments

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 and long-term debt measured and carried at fair value, 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, which 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	March 31, 2018		December 31, 2017	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	854	+126 -126	853	+130 -130
Unit contingent power purchases	6	+5 -5	44	+7 -9
Structured products - Eastern US	18	+6 -6	17	+8 -7
Hydro Slice products - Western US	(4)	+4 -2	(2)	+3 -3
Long-term wind energy sale - Eastern US	(20)	+19 -19	—	—
Others	5	+5 -5	6	+8 -8

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 2019, 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 averaging external fundamental-based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at March 31, 2018 are US$25 - US$34 (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 weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2017 to March 31, 2018, the base fair value and the sensitivity values have increased by approximately $21 million and $3 million, respectively.

ii. 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 at fair value through profit and loss.

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 March 31, 2018, are nil (Dec. 31, 2017 - nil) and 2.20 per cent to 2.76 per cent (Dec. 31, 2017 – 2.20 per cent to 2.76 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 1.08 per cent to 1.91 per cent (Dec. 31, 2017 - 1.1 per cent to 1.94 per cent) and a change in volumetric discount rates of approximately 7.77 per cent to 10.33 per cent (Dec. 31, 2017 - 7.77 per cent to 10.46 per cent), which approximate one standard deviation for each input.

iii. 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 March 31, 2018, are 74 per cent to 153 per cent and 75 per cent to 121 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 5 per cent to 7 per cent (Dec. 31, 2017 - 7 per cent) and a change in non-standard shape factors of approximately 3 per cent to 5 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 March 31, 2018, are 16 per cent to 33 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 18 per cent to 23 per cent and 10 per cent, respectively (Dec. 31, 2017 -27 per cent to 32 per cent and 10 per cent.

iv. Hydro Slice Products - Western US

The Corporation agreed to purchase power contingent upon the actual generation of specific hydro units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed capacity payment. The contracts were accounted for as fair value through profit and loss.

The key unobservable inputs used in the March 31, 2018 valuations are delivered volume expectations. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements. This analysis is based on historical production of the generation units for available history. For the Level III base fair value measurement at March 31, 2018, the volumes were assumed to be equal to the 50th percentile (Dec. 31, 2017 - 50th percentile) of the historical production. The Corporation's assessment of a reasonably possible change in delivered volumes is 24 per cent (Dec. 31, 2017 - 24 per cent).

v. Long-Term Wind Energy Sale - Eastern US

In relation to the acquisition of the US wind project (See Note 3 for further details), 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 based on proxy generation. Commercial operation of the facility is expected to begin in September of 2019, with the contract extending for 15 years after commercial commencement. 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. Forward power and REC price ranges per MWh used in determining the Level III base fair value at March 31, 2018 are US$38-$59 and US$7 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 is a reasonably possible change.

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 March 31, 2018, are as follows: Level I - $2 million net liability (Dec. 31, 2017 - $1 million net liability), Level II - $26 million net asset (Dec. 31, 2017 - $42 million net liability), Level III - $725 million net asset (Dec. 31, 2017 - $771 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the 3 months ended March 31, 2018 are primarily attributable to the settlement of contracts, unfavourable market price changes on existing 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:

	3 months ended March 31, 2018			3 months ended March 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	**4**	**(19)**	**(15)**	40	8	48
Market price changes on new contracts	**—**	**1**	**1**	—	8	8
Contracts settled	**(22)**	**(25)**	**(47)**	(15)	(3)	(18)
Change in foreign exchange rates	**18**	**1**	**19**	(12)	—	(12)
Transfers into Level III	**—**	**(4)**	**(4)**	—	—	—
Net risk management assets at end of period	**719**	**6**	**725**	739	45	784
Additional Level III information:						
Gains recognized in other comprehensive income	**22**	**—**	**22**	28	—	28
Total gains (losses) included in earnings before income	**22**	**(17)**	**5**	15	16	31
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(42)**	**(42)**	—	13	13

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 March 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 three months 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				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value**
Long-term debt - March 31, 2018	**—**	**3,358**	**—**	**3,358**	**3,345**
Long-term debt - Dec. 31, 2017	—	3,708	—	3,708	3,638

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, restricted cash, 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 Corporation's loan receivable and the finance lease receivables 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 Condensed 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:

3 months ended March 31	2018	2017
Unamortized net gain at beginning of period	**105**	148
New inception gain (loss)	**(16)**	5
Change in foreign exchange rates	**3**	(2)
Amortization recorded in net earnings during the year	**(8)**	(8)
Unamortized net gain at end of period	**84**	143

10. 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 applies 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 a 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 March 31, 2018

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	81	17	98
Long-term	621	30	651
Net commodity risk management assets	702	47	749
Other			
Current	2	(1)	1
Long-term	(1)	(2)	(3)
Net other risk management assets (liabilities)	1	(3)	(2)
Total net risk management assets	703	44	747

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

C. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments, which are also more fully discussed in Note 14(b) of the Corporation's most recent annual consolidated financial statements.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

i. Commodity Price Risk – 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 March 31, 2018, associated with the Corporation's proprietary trading activities was $2 million (Dec. 31, 2017 - $5 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 March 31, 2018, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $8 million (Dec. 31, 2017 - $16 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 March 31, 2018, associated with these transactions was $2 million (Dec. 31, 2017 - $5 million).

b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the US dollar, the Japanese yen, the euro 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. Further discussion on Currency Rate Risk can be found in Note 14(B)(I)(c) of the Corporation's most recent annual consolidated financial statements.

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 March 31, 2018:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables(1)	81	19	**100**	**671**
Long-term finance lease receivables	97	3	**100**	**209**
Risk management assets(1)	99	1	**100**	**876**
Loan receivable(2)	—	100	**100**	**33**
Total				**1,789**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparty has no external credit rating. Excludes $5 million current portion classified in trade and other receivables.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at March 31, 2018, was $16 million (Dec. 31, 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. As at March 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.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Accounts payable and accrued liabilities	496	—	—	—	—	—	496
Long-term debt[1]	117	467	472	399	594	1,322	3,371
Commodity risk management assets	78	111	94	103	103	260	749
Other risk management (assets) liabilities	1	(3)	(2)	(1)	3	—	(2)
Finance lease obligations	13	15	12	7	4	15	66
Interest on long-term debt and finance lease obligations[2]	161	153	124	103	97	702	1,340
Dividends payable	34	—	—	—	—	—	34
Total	**900**	**743**	**700**	**611**	**801**	**2,299**	**6,054**

(1) Excludes impact of hedge accounting.
(2) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

D. Collateral and 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 March 31, 2018, the Corporation had posted collateral of $149 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 $69 million (Dec. 31, 2017 - $96 million) of collateral to its counterparties.

11. 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
As at As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
Additions	—	—	—	—	—	19	4	23
Additions - finance lease	—	—	—	—	1	—	—	1
Acquisitions *(Note 3)*	—	—	—	—	—	4	—	4
Depreciation	—	(64)	(20)	(31)	(28)	—	(4)	(147)
Revisions and additions to decommissioning and restoration	—	(6)	(1)	(1)	(2)	—	—	(10)
Retirement of assets and (disposals)	—	—	(1)	—	(2)	—	—	(3)
Change in foreign exchange rates	1	7	6	6	1	—	2	23
Transfers	—	14	1	2	4	(24)	3	—
As at March 31, 2018	**96**	**2,408**	**895**	**2,167**	**576**	**94**	**233**	**6,469**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive, or planned maintenance.

12. Credit Facilities, Long-Term Debt, and Finance Lease Obligations

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at	March 31, 2018			Dec. 31, 2017		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**325**	**325**	**3.3%**	27	27	2.8%
Debentures	**1,047**	**1,051**	**6.0%**	1,046	1,051	6.0%
Senior notes(3)	**891**	**903**	**5.4%**	1,499	1,510	6.0%
Non-recourse(4)	**1,010**	**1,021**	**4.3%**	1,022	1,032	4.3%
Other(5)	**72**	**71**	**7.1%**	44	44	9.2%
	3,345	**3,371**		3,638	3,664	
Finance lease obligations	**66**			69		
	3,411			3,707		
Less: current portion of long-term debt	**(123)**			(729)		
Less: current portion of finance lease obligations	**(17)**			(18)		
Total current long-term debt and finance lease obligations	**(140)**			(747)		
Total credit facilities, long-term debt, and finance lease obligations	**3,271**			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 March 31, 2018 - US$0.7 billion (Dec. 31, 2017 - US$1.2 billion).
(4) Includes US$25 million at March 31, 2018 (Dec. 31, 2017 - US$27 million).
(5) Includes US$23 million at March 31, 2018 (Dec. 31, 2017 - US$24 million) of tax equity financing.

On March 15, 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.

As a result of the Corporation's repayment of its US$500 million Senior Notes the Corporation now has US$380 million (Dec. 31, 2017 - US$480 million) of US-dollar-denominated debt designated as hedges of its net investment in foreign operations.

The Corporation has a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, comprised of the Corporation's $1.0 billion committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of $500 million (Dec. 31, 2017 - $500 million), and the Corporation's US$200 million and $240 million committed bilateral facilities. These facilities expire in 2021, 2021, 2020, and 2019 respectively. The $1.5 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.

In total, $1.1 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At March 31, 2018, the $0.9 billion (Dec. 31, 2017 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (Dec. 31, 2017 - nil) and letters of credit of $0.6 billion (Dec. 31, 2017 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.1 billion available under the credit facilities, the Corporation also has $329 million of available cash and cash equivalents.

The Corporation's total outstanding letters of credit as at March 31, 2018 were $639 million (Dec. 31, 2017 - $677 million), including TransAlta Renewables outstanding letters of credit of $69 million (Dec. 31, 2017 - $69 million) with no (Dec. 31, 2017 - nil) amounts exercised by third parties under these arrangements. The Corporation and TransAlta Renewables both have an uncommitted $100 million demand letter of credit facility.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at March 31, 2018, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Corporation's subsidiaries have issued non-recourse bonds of $1,010 million (Dec. 31, 2017 - $1,022 million) that 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 first quarter. However, funds in these entities that have accumulated since the first quarter test will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2018. At March 31, 2018, $53 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 March 31, 2018. However, as at March 31, 2018, $1 million (Dec. 31, 2017 - $1 million) of cash was on deposit for certain reserve accounts that do not allow the use of letter of credits and was not available for general use.

C. Security

Non-recourse debts of $845 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 $1,094 million at March 31, 2018 (Dec. 31, 2017 - $1,107 million). At March 31, 2018, a non-recourse bond of approximately $165 million (Dec. 31, 2017 - $174 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

D. Restricted Cash

The Corporation has $31 million (Dec. 31, 2017 - $30 million) of restricted cash related to the Kent Hills project financing which is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, including commissioning of the Kent Hills 3 wind project.

13. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

3 months ended March 31	2018		2017	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**287.9**	**3,095**	287.9	3,095
Shares purchased and retired under NCIB	**(0.4)**	**(4)**	—	—
	287.5	**3,091**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**(1)**	—	(1)
Issued and outstanding, end of period	**287.5**	**3,090**	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 three months ended March 31, 2108:

As at	March 31, 2018	Dec. 31, 2017
Total shares purchased	**374,900**	—
Average purchase price per share	**$ 6.97**	—
Total cost	**3**	—
Weighted average book value of shares cancelled	**4**	—
Increase to retained earnings	**(1)**	—

C. Dividends

On April 19, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on July 3, 2018.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

D. Stock Options

The stock options granted to executive officers of the Corporation during the three months ended March 31, 2018 and 2017 are as follows:

Grant month	**Number of stock options granted** *(millions)*	**Exercise price**	**Vesting period** *(years)*	**Expiration length** *(years)*
March 2018	0.7	$ 7.45	3	7
March 2017	0.7	$ 7.25	3	7

14. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares, other than the Series B preferred shares which are non-voting cumulative redeemable floating rate first preferred shares.

As at March 31, 2018 and Dec. 31, 2017, the Corporation had 10.2 million Series A, 11.0 million Series C, 9.0 million Series E, 6.6 million Series G Cumulative Redeemable Rate Rest First Preferred Shares issued and outstanding and 1.8 million Series B Cumulative Redeemable Floating Rate First Preferred Shares issued and outstanding.

B. Dividends

The following summarizes the preferred share dividends declared within the three months ended March 31:

		3 months ended March 31	
Series	**Quarterly amounts per share**	**2018**	2017[(1)]
A	0.16931	2	–
B	0.17889[(2)]	–	–
C	0.25169	3	–
E	0.32463	3	–
G	0.33125	2	–
Total for period		**10**	–

(1) No dividends were declared in the first quarter of 2017 as on Dec. 19, 2016, the quarterly dividend related to the period covering the first quarter of 2017 was declared.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent, and represented approximately $300 thousand in dividends.

On April 19, 2018 the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.19951 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on July 3, 2018.

15. Commitments and Contingencies

A. 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 (the "LLRP") 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 Alberta Electric System Operator 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 potential retroactive exposure faced by the Corporation for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if the Corporation and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil. The Corporation has recorded a provision of $7.5 million as at March 31, 2018 and Dec. 31, 2017.

II. FMG Disputes

The Corporation is currently engaged in two pieces of litigation 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 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. The Corporation is disputing the termination payment it received. The Balancing Pool excludes certain mining assets that the Corporation believes should be included in the net book value calculation for an additional $56 million, which is subject to the PPA arbitration process.

16. Segment Disclosures

A. Reported Segment Earnings

I. Earnings Information

3 months ended March 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	269	87	62	41	86	27	17	(1)	588
Fuel and purchased power	196	44	29	2	6	1	—	(1)	277
Gross margin	73	43	33	39	80	26	17	—	311
Operations, maintenance, and administration	47	15	13	9	13	8	8	20	133
Depreciation and amortization	50	16	11	12	27	8	—	6	130
Taxes, other than income taxes	3	1	1	—	2	1	—	—	8
Net other operating income	(168)	—	—	—	—	—	—	—	(168)
Operating income (loss)	141	11	8	18	38	9	9	(26)	208
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(68)
Foreign exchange loss									(2)
Earnings before income taxes									140

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits.

3 months ended March 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	250	88	102	26	87	24	1	–	578
Fuel and purchased power	139	64	39	2	5	1	–	–	250
Gross margin	111	24	63	24	82	23	1	–	328
Operations, maintenance, and administration	44	13	12	7	12	8	5	24	125
Depreciation and amortization	70	15	9	7	27	8	–	7	143
Taxes, other than income taxes	3	1	1	–	2	1	–	–	8
Net other operating income	(10)	–	–	–	–	–	–	–	(10)
Operating income (loss)	4	(5)	41	10	41	6	(4)	(31)	62
Finance lease income	–	–	3	13	–	–	–	–	16
Net interest expense									(62)
Foreign exchange loss									(1)
Earnings before income taxes									15

B. Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Condensed Consolidated Statements of Earnings and the Condensed Consolidated Statements of Cash Flows is presented below:

3 months ended March 31	**2018**	2017
Depreciation and amortization expense on the Condensed Consolidated Statements of Earnings	**130**	143
Depreciation included in fuel and purchased power	**31**	17
Depreciation and amortization on the Condensed Consolidated Statements of Cash Flows	**161**	160

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 Condensed Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended March 31, 2018:

Earnings coverage on long-term debt supporting the Corporation's Shelf Prospectus

1.16 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.

Disclosure Controls and Procedures

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

There have been no other changes in our internal control over financial reporting during the period ended March 31, 2018, that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at March 31, 2018, the end of the period covered by this report, our disclosure controls and procedures were effective.

Supplemental Information

		March 31, 2018	December 31, 2017
Closing market price (TSX) ($)		**6.98**	7.45
Price range for the last 12 months (TSX) ($)	High	**8.50**	8.50
	Low	**6.31**	6.88
FFO before interest to adjusted interest coverage(2)(times)		**4.2**	4.3
Adjusted FFO to adjusted net debt[2](%)		**20.9**	20.4
Adjusted net debt to comparable EBITDA[1,2] (times)		**3.4**	3.6
Adjusted net debt to invested capital[1] (%)		**47.4**	49.5
Return on equity attributable to common shareholders[2](%)		**(6.5)**	(10.0)
Return on capital employed[2](%)		**3.9**	2.1
Earnings coverage[2](times)		**1.2**	0.6
Dividend payout ratio based on FFO[1,2](%)		**5.0**	4.3
Dividend coverage[2](times)		**17.3**	14.1
Dividend yield[2](%)		**2.3**	2.1

(1) These ratios incorporate items that are not defined under IFRS. None of these measurements should be used in isolation or as a substitute for the Corporation's reported financial performance or position as presented in accordance with IFRS. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application. For a reconciliation of the non-IFRS measures used in these calculations, refer to the Discussion of Financial Results section of this MD&A.
(2) Last 12 months.

Ratio Formulas

FFO before interest to adjusted interest coverage = FFO + interest on debt and finance lease obligations - interest income - capitalized interest / interest on debt and finance lease obligations + 50 per cent dividends paid on preferred shares - interest income

Adjusted FFO to adjusted net debt = FFO - 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

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 + 50 per cent issued preferred shares - cash and cash equivalents / comparable EBITDA

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 / adjusted net debt + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares

Return on equity attributable to common shareholders = net earnings attributable to common shareholders / equity attributable to shareholders excluding AOCI - issued preferred shares

Return on capital employed = earnings before non-controlling interests and income taxes + net interest expense - earnings attributable to non-controlling interests + net interest expense / invested capital excluding AOCI

Earnings coverage = net earnings attributable to shareholders + income taxes + net interest expense / interest on debt and finance lease obligations + 50 per cent dividends paid on preferred shares - interest income

Dividend payout ratio = dividends declared on common shares / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage ratio based on comparable FFO = FFO - 50 per cent dividends / cash dividends paid on common shares

Dividend yield = dividend paid per common share / current period's closing market price

Glossary of Key Terms

Availability - A measure of the 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.

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

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.

Gigawatt - A measure of electric power equal to 1,000 megawatts.

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

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

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.

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

Unplanned Outage - The shut-down of a generating unit due to an unanticipated breakdown.

TransAlta Corporation
110 - 12th Avenue S.W.
Box 1900, Station "M"
Calgary, Alberta Canada T2P 2M1

Phone
403.267.7110

Website
www.transalta.com

AST Trust Company (Canada)
P.O. Box 700 Station "B"
Montreal, Québec Canada H3B 3K3

Phone Toll-free in North America: 1.800.387.0825
Toronto or outside North America: 416.682.3860

Fax 514.985.8843

E-mail
inquiries@canstockta.com

Website www.canstockta.com

FOR MORE INFORMATION

Media and Investor Inquiries
Investor Relations

Phone1.800.387.3598 in Canada and United States
or 403.267.2520

Fax
403.267.7405
E-mail
investor_relations@transalta.com

EXHIBIT D

Canada (Eastern)							
Facility Name	**Location**	**Fuel**	**MW**	**Ownership**	**Net MW**	**Operator**	**COD**
Mississauga	Mississauga, ON	Gas	108	50%	54	Yes	1992
Ottawa	Ottawa, ON	Gas	74	50%	37	Yes	1992
Sarnia	Sarnia, ON	Gas	506	100%	506	Yes	2003
Windsor	Windsor, ON	Gas	72	50%	36	Yes	1996
Appleton	Almonte, ON	Hydro	1	100%	1	Yes	1994
Galetta	Galetta, ON	Hydro	2	100%	2	Yes	1907
Misema	Englehart, ON	Hydro	3	100%	3	Yes	2003
Moose Rapids	Sudbury, ON	Hydro	1	100%	1	Yes	1997
Ragged Chute	New Liskeard, ON	Hydro	7	100%	7	Yes	1991
Kent Breeze	Thamesville, ON	Wind	20	100%	20	Yes	2011
Kent Hills	Kent Hills, NB	Wind	150	83%	125	Yes	2008
Le Nordais	Matane, QC	Wind	98	100%	98	Yes	1999
Melancthon	Shelburne, ON	Wind	200	100%	200	Yes	2006
New Richmond	New Richmond, QC	Wind	68	100%	68	Yes	2013
Wolfe Island	Wolfe Island, ON	Wind	198	100%	198	Yes	2009
Total			**1,508**		**1,356**		

Canada (Western)							
Facility Name	**Location**	**Fuel**	**MW**	**Ownership**	**Net MW**	**Operator**	**COD**
Genesee 3	Genesee, AB	Coal	466	50%	233	No	2005
Keephills	Wabamun, AB	Coal	790	100%	790	Yes	1983
Keephills 3	Wabamun, AB	Coal	463	50%	232	Yes	2011
Sheerness	Hanna, AB	Coal	780	25%	195	No	1986
Sundance	Wabamun, AB	Coal	2,141	100%	2,141	Yes	1970-1980
Fort Saskatchewan	Fort Saskatchewan, AB	Gas	118	30%	35	Yes	1999
Poplar Creek	Fort McMurray, AB	Gas	224	100%	224	No	2001
Akolkolex	Revelstoke, BC	Hydro	10	100%	10	Yes	1995
Barrier	Seebe, AB	Hydro	13	100%	13	Yes	1947
Bearspaw	Calgary, AB	Hydro	17	100%	17	Yes	1954
Belly River	Glenwood, AB	Hydro	3	100%	3	Yes	1991
Bighorn	Nordegg, AB	Hydro	120	100%	120	Yes	1972
Bone Creek	Valemount, B.C.	Hydro	19	100%	19	Yes	2011
Brazeau	Drayton Valley, AB	Hydro	355	100%	355	Yes	1965
Cascade	Banff, AB	Hydro	36	100%	36	Yes	1942
Ghost	Cochrane, AB	Hydro	54	100%	54	Yes	1929
Horseshoe	Seebe, AB	Hydro	14	100%	14	Yes	1911
Interlakes	Kananaskis, AB	Hydro	5	100%	5	Yes	1955
Kananaskis	Seebe, AB	Hydro	19	100%	19	Yes	1913
Pingston	Revelstoke, BC	Hydro	45	50%	23	Yes	2003-2004
Pocaterra	Kananaskis, AB	Hydro	15	100%	15	Yes	1955
Rundle	Canmore, AB	Hydro	50	100%	50	Yes	1951
Spray	Canmore, AB	Hydro	112	100%	112	Yes	1951
St. Mary	Magrath, AB	Hydro	2	100%	2	Yes	1992
Taylor	Magrath, AB	Hydro	13	100%	13	Yes	2000
Three Sisters	Canmore, AB	Hydro	3	100%	3	Yes	1951
Upper Mamquam	Squamish, BC	Hydro	25	100%	25	Yes	2005
Waterton	Glenwood, AB	Hydro	3	100%	3	Yes	1992
Ardenville	Fort Macleod, AB	Wind	69	100%	69	Yes	2010

Blue Trail	Fort Macleod, AB	Wind	66	100%	66	Yes	2009
Castle River	Pincher Creek, AB	Wind	44	100%	44	Yes	1997
Cowley North	Pincher Creek, AB	Wind	20	100%	20	Yes	2001
Macleod Flats	Fort Macleod, AB	Wind	3	100%	3	Yes	2004
McBride Lake	Fort Macleod, AB	Wind	75	50%	38	Yes	2003
Sinnott	Pincher Creek, AB	Wind	7	100%	7	Yes	2001
Soderglen	Fort Macleod, AB	Wind	71	50%	35	Yes	2006
Summerview	Pincher Creek, AB	Wind	70	100%	70	Yes	2004
Summerview 2	Pincher Creek, AB	Wind	66	100%	66	Yes	2010
Total			**6,406**		**5,178**		

United States							
Facility Name	**Location**	**Fuel**	**MW**	**Ownership**	**Net MW**	**Operator**	**COD**
Centralia	Centralia, WA	Coal	1,340	100%	1,340	Yes	1971
Skookumchuck	Centralia, WA	Hydro	1	100%	1	Yes	1970
Mass Solar	Dartmouth and region, MA	Solar	21	100%	21	No	2012-2015
Lakeswind	Rollag, MN	Wind	50	100%	50	Yes	2014
Wyoming Wind	Evanston, WY	Wind	144	100%	144	No	2003
Total			**1,556**		**1,556**		

Australia							
Facility Name	**Location**	**Fuel**	**MW**	**Ownership**	**Net MW**	**Operator**	**COD**
South Hedland	South Hedland, WA	Gas/Diesel	150	100%	150	Yes	2017
Parkeston	Kalgoorlie, WA	Gas	110	50%	55	Yes	1996
Southern Cross	Kalgoorlie and region, WA	Gas	245	100%	245	Yes	1996
Total			**505**		**450**		

Total Generation	**9,975**	**8,540**

TransAlta Corporation Simplified Corporate Ownership Structure

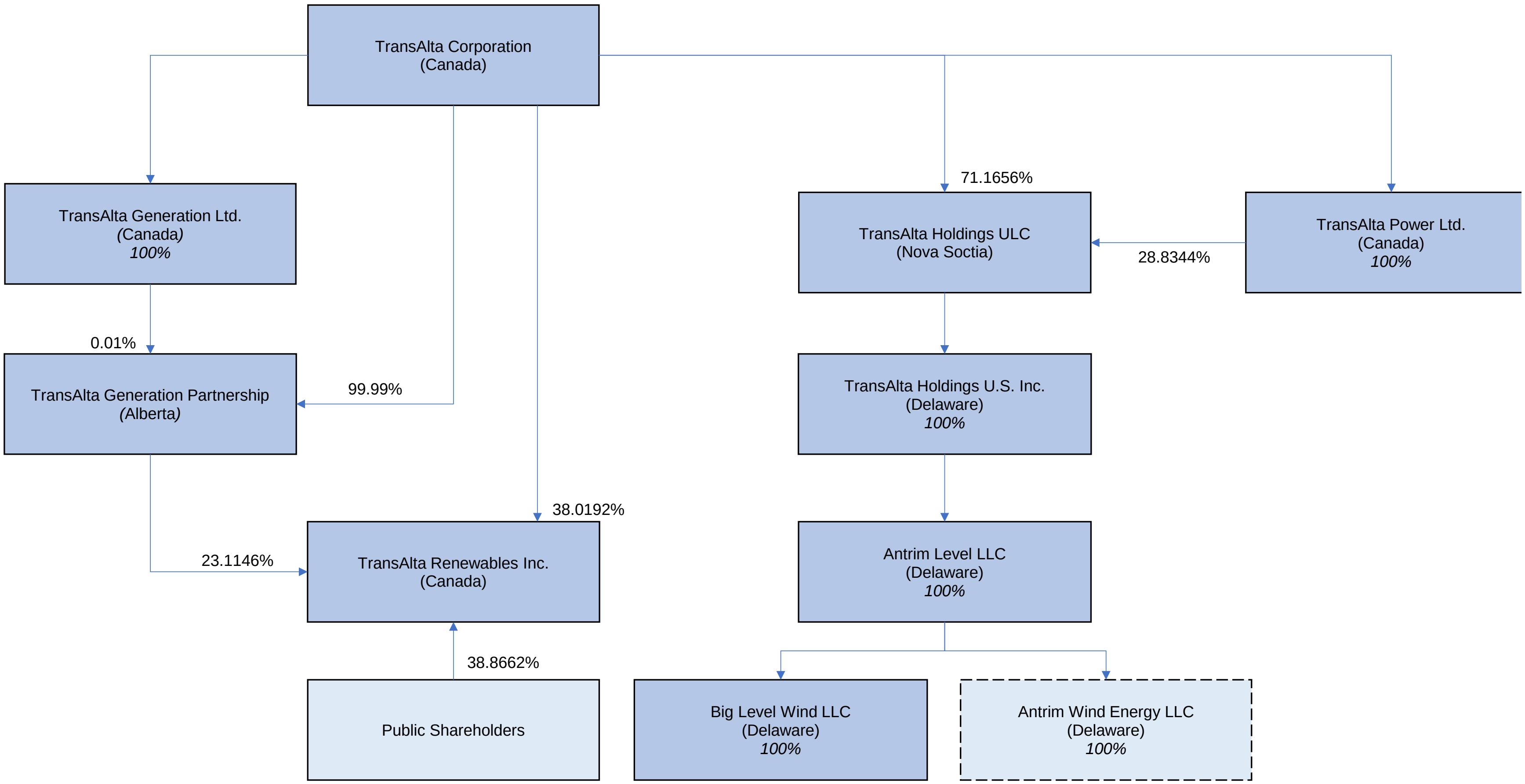


EXHIBIT E

EXHIBIT F

Executive Leadership Biographies

Dawn L. Farrell, President and Chief Executive Officer

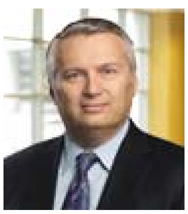
Mrs. Farrell became President and CEO of TransAlta on January 2, 2012. Prior to her appointment, she served as Chief Operating Officer (2009 to 2011) and Executive Vice-President, Commercial Operations and Development (2008 to 2009). Mrs. Farrell has over 30 years of experience in the electric energy industry.

Mrs. Farrell is also a member of the Board of Directors of The Chemours Company, a chemical company listed on the NYSE, The Conference Board of Canada and the Business Council of Canada. Mrs. Farrell is also a member of The Canada-U.S. Council for Advancement of Women Entrepreneurs and Business Leaders. Past board memberships include the Calgary Stampede, the Mount Royal College Board of Governors, Fording Coal Income Fund, New Relationship Trust Fund, Mount Royal College Foundation and Vision Quest Windelectric.

Brett M. Gellner, Chief Investment Officer and Acting Chief Financial Officer

Mr. Gellner became TransAlta's Chief Investment Officer on March 31, 2014 and is responsible for all strategic corporate investments, mergers and acquisitions, and greenfield projects. Prior to being appointed to this position, he was Chief Financial Officer (2010 to 2014) and Vice-President, Commercial Operations (2008 to 2009).

Mr. Gellner has significant experience in finance, valuation, economics, mergers and acquisitions, and commercial agreements. He also has extensive knowledge of the power industry, having worked as co-head of CIBC World Markets' Power & Utilities group where he was involved in numerous transactions including leveraged buy-outs, high yield and investment-grade debt financings, initial public offerings, hybrid securities financings and private offerings of equity and debt. Prior to CIBC World Markets, he held senior roles in the Mergers & Acquisitions and Corporate Development groups of a large, publicly traded company and a major international consulting firm.



John H. Kousinioris, Chief Legal and Compliance Officer & Corporate Secretary

Mr. Kousinioris joined TransAlta on December 3, 2012. He is TransAlta's Chief Legal and Compliance Officer and Corporate Secretary and is responsible for directing TransAlta's legal affairs, government relations, regulatory compliance and corporate secretarial matters. Mr. Kousinioris is also President of TransAlta Renewables.

Prior to joining TransAlta, Mr. Kousinioris was a partner and co-head of the corporate commercial department at Bennett Jones LLP. He has over 25 years of experience in securities law, mergers and acquisitions and corporate governance matters, and has represented clients in some of Canada's largest public offerings and merger transactions.

Dawn E. de Lima, Chief Administrative Officer

Mrs. de Lima started with TransAlta on January 23, 2006 and was appointed Chief Human Resources Officer on March 15, 2011, and then Chief Administrative Officer on September 14, 2015. She is responsible for leading human resources, information technology, supply chain management, corporate communications, Indigenous relations and corporate security, as well as overseeing the company's general administration. She directs the design and successful implementation of standards across the organization, is focused on the execution of a long-term plan that addresses current and future talent demands, ensures we maintain strong relationships with internal and external stakeholders, safeguards the company's reputation and ensures that both our cyber and corporate security practices are best-in-class.

Prior to joining TransAlta, Dawn spent nearly two decades as a business leader in human resources and communications, holding senior positions in Bell Canada and Norigen Communications. Currently, she is the Chair of the Board of Directors for Junior Achievement Canada.

Aron Willis, Senior Vice-President, Gas & Renewables

Mr. Willis joined the TransAlta in 1999 and is Senior Vice-President, Gas & Renewables. He leads TransAlta's Gas and Renewable operations and oversees the company's operations services team, including Supply Chain Management, EH&S, Operations Integrity and the project management office. Aron is also responsible for managing all joint ventures and partnerships relating to TransAlta's gas, wind, hydro and solar operations and the regulated transmission business.

Since joining TransAlta, Aron has worked throughout the business in increasing levels of responsibility including roles in Finance, Operations, and Major Maintenance. Prior to his current role, Aron spent nearly 10 years as the Managing Director of TransAlta's business in Australia. Based in Perth, Western Australia, Aron oversaw a significant expansion of the business comprising an investment of just under $1 billion in new contracted assets. This included the development, contracting and construction of the $570 million South Hedland Power Station. Aron sits on the management team of TransAlta Renewables Incorporated and he holds a Bachelor of Commerce in Finance from the University of Calgary.