UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[Check one]

o REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

OR

x ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended	Dec 31, 2019	Commission file number	001-15214

TRANSALTA CORPORATION
(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(I.R.S Employer Identification Number (if applicable))

110-12th Avenue S.W., Box 1900, Station "M",
Calgary, Alberta, Canada, T2P 2M1,
(403) 267-7110
(Address and telephone number of Registrant's principal executive offices)

TransAlta Centralia Generation LLC
913 Big Hanaford Road, Centralia, Washington 98531, (360) 736-9901
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, no par value	New York Stock Exchange
Common Share Purchase Rights	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

Debt Securities

For annual reports, indicate by check mark the information filed with this form:

x Annual information form

x Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

At December 31, 2019, 277,265,641 common shares were issued and outstanding.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes x No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ¨

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ¨

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

INCORPORATION BY REFERENCE

The documents, forming part of this Form 40-F, are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended.

Form	Registration No.
S-8	333-72454
S-8	333-101470
F-10	333-229991

CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

A. Consolidated Audited Annual Financial Statements

For consolidated audited annual financial statements, including the report of independent chartered professional accountants with respect thereto, see Exhibit 13.3 incorporated by reference herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see Exhibit 13.2 incorporated by reference herein.

DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934 ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2019, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting.

Internal control over financial reporting refers to a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and members of our board of directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management evaluated the effectiveness of our internal control over financial reporting as of December 31, 2019 using the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 framework. Management concluded that our internal control over financial reporting was effective as of December 31, 2019. Certain matters relating to the scope of management's evaluation and limitations of management's conclusions are described below. See "Limitations and Scope of Management's Report on Internal Control over Financial Reporting."

Our Chartered Professional Accountants, Ernst & Young LLP, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2019. For the Report of Independent Registered Public Accounting Firm see page F3 of the Consolidated Audited Annual Financial Statements for the year ended December 31, 2019 filed as Exhibit 13.3 and incorporated by reference herein, under the heading "Report of Independent Registered Public Accounting Firm".

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

LIMITATIONS AND SCOPE OF MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

TransAlta Corporation ("TransAlta" or the "Company") proportionately consolidates the accounts of the Sheerness, Pioneer Pipeline and Genesee 3 joint operations (the "Excluded Entities"), in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these Excluded Entities. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these Excluded Entities. Accordingly, management's evaluation of the Company's internal control over financial reporting did not include an evaluation of the internal controls of any of the Excluded Entities, and management's conclusion regarding the effectiveness of the Company's internal control over financial reporting does not extend to the internal controls of any of the Excluded Entities.

The 2019 consolidated financial statements of TransAlta, in accordance with EITF 00-1, included CDN$359 million and CDN$326 million of total and net assets, respectively, as of December 31, 2019, and CDN$238 million and CDN$133 million of revenues and net earnings, respectively, for the year then ended related to Excluded Entities. Once the financial information is obtained from these Excluded Entities it falls within the scope of TransAlta's internal control framework.

AUDIT COMMITTEE FINANCIAL EXPERT

TransAlta's board of directors has determined that it has two audit committee financial experts serving on its Audit, Finance and Risk Committee (the "AFRC"). Ms. Beverlee F. Park, Mr. Robert C. Flexon and Mr. Bryan D. Pinney have each been determined to be an audit committee financial expert, within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley"), and are independent, as that term is defined by the New York Stock Exchange's ("NYSE") listing standards applicable to the Registrant. Under Securities and Exchange Commission rules, the designation of persons as audit committee financial experts does not make them "experts" for any other purpose, impose any duties, obligations or liability on them that are greater than those imposed on members of their committee and the board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of their committee.

CODE OF ETHICS

TransAlta has adopted a code of ethics as part of its "Corporate Code of Conduct" that applies to all employees and officers which has been filed with the Securities and Exchange Commission. In addition, the Registrant has adopted a code of conduct applicable to all directors of the Company, a separate financial code of conduct which applies to all financial management employees and an Energy Trading code of conduct for our employees working within energy marketing. Our codes of conduct are available on our Internet website at www.transalta.com. There has been no waiver of the codes granted during the 2019 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2019 and December 31, 2018, Ernst & Young LLP and its affiliates billed or expect to bill , including out-of-pocket costs, $4,306,184 and $4,540,012, respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31		**2019**		**2018**
Audit Fees[1]	$	2,492,025	$	2,810,805
Audit-related fees[1][2]		1,375,038		1,614,452
Tax fees		439,121		104,255
All other fees		0		10,500
Total	$	4,306,184	$	4,540,012

(1) Comparative figures have been reclassified to confirm to the current periods classification of fees.

(2) Included in the audit-related fees are $887,257(2018 - $1,035,548) of fees billed to TransAlta Renewables.

All amounts are in Canadian dollars unless otherwise stated.

No other audit firms provided audit services in 2019 or 2018.

The nature of each category of fees is described below:

Audit Fees

Audit fees are for professional services rendered for the audit and review of our financial statements or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents.

Audit-Related Fees

Assurance and related services that are reasonably related to the performance of the audit or review of our financial statements that are not included under *"Audit Fees".* Audit-Related fees include statutory audits, pension audits and other compliance audits. In 2019, we have included the fees billed to TransAlta Renewables, a controlled and consolidated subsidiary of TransAlta.

Tax Fees

Tax fees are tax-related services for review of tax returns, assistance with questions on tax audits, and tax planning.

All Other Fees

Products and services provided by the 'Corporation's auditor other than those services reported under *"Audit Fees"*, *"Audit-Related Fees"* and *"Tax Fees"*. This includes fees related to training services provided by the auditor.

Pre-Approval Policies and Procedures

The AFRC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the AFRC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the AFRC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act of 2002. This policy also provides that the Chair of the AFRC may approve permissible non-audit services during the quarter and report such approval to the AFRC at its next regularly scheduled meeting.

Percentage of Services Approved by the AFRC

For the year ended December 31, 2019, none of the services described above were approved by the AFRC pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

OFF-BALANCE SHEET ARRANGEMENTS

TransAlta currently has no off-balance sheet arrangements. See page M53 of Exhibit 13.2, incorporated by reference herein under the heading "Unconsolidated Structured Entities or Arrangements".

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page M54 of Exhibit 13.2, incorporated by reference herein, under the heading "Other Consolidated Analysis" and page F94 under the heading "Commitments and Contingencies" of Exhibit 13.3, all incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

We have a separately-designated standing AFRC established in accordance with Section 3(a)58(A) of the Exchange Act, and made up of independent directors. The members of the AFRC are:

Beverlee F. Park (Chair)
Robert C. Flexon
Alan J. Fohrer
Bryan D. Pinney

MINE SAFETY

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 13.1, incorporated herein, under the heading “Business of TransAlta – U.S. Coal Business Segment”.

FORWARD-LOOKING INFORMATION

This Form 40-F, the documents incorporated herein by reference, and other reports and filings of the Company made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on assumptions relating to information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast" "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance 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 Form 40-F (or a document incorporated herein by reference) contains forward-looking statements including, but not limited to statements pertaining to: our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2018 to beyond 2031; potential for growth in renewables, and greenfield development acquisitions; the amount of capital allocated to new growth; our business and anticipated future financial performance; our success in executing on our growth projects; the timing and the completion of growth projects, including major projects such as the Brazeau Pumped Storage Project and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the conversion of our coal fired units to natural gas, and the timing thereof; the form of any definitive agreement with Tidewater regarding the construction of a pipeline; the terms of the current or any further proposed Normal Course Issuer Bid, including timing, and number of shares to be repurchased pursuant to such Normal Course Issuer Bid; the mothballing of certain units; the impact of certain hedges on future earnings and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity, including for clean energy, in both the short-term and long-term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas and other fuel costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, including the change to a capacity market in Alberta and the expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions;

accounting estimates; anticipated growth rates in our markets; our expectations relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; and our credit practices.

The forward-looking statements contained in this Form 40-F (or a document incorporated herein by reference) are based on many assumptions including, but not limited to, the following material assumptions: no significant changes to applicable laws, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the investment and credit markets; assumptions related to 2019 guidance include: Alberta spot power price equal CDN$50 to CDN$60 per MWh; Alberta contracted power price equal to CDN$50 to CDN$55 per MWh; Mid-C spot power prices equal to US$20 to US$25 per MWh; Mid-C contracted power price of US$47 to US$53 per MWh; sustaining capital between CDN$160 million and CDN$190 million; productivity capital of CDN$10 to CDN$15 million; Sundance coal capacity factor of 30%; hydro and wind resource being approximately in-line with long-term average; our proportionate ownership of TransAlta Renewables not changing materially; no material decline in the dividends expected to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion; assumptions regarding the ability of the converted units to successfully compete in the Alberta capacity market; and assumptions regarding the our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables, and being able to realize the full economic benefit from the capacity, energy and ancillary services from our Alberta hydro assets once the applicable power purchase arrangement has expired.

Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this Form 40-F (or a document incorporated herein by reference) include, but are not limited to, risks relating to: fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic or market conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather and other climate-change related risks; unexpected increases in cost structure and disruptions in the source of fuels, water or wind required to operate our facilities; failure to meet financial expectations; natural and man-made disasters resulting in dam failures; the threat of domestic terrorism and cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, TransAlta Renewables Inc.; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks; increased costs or delays in the construction or commissioning of pipelines to converted units; changes in expectations in the payment of future dividends, including from TransAlta Renewables Inc.; insurance coverage; credit ratings; our provision for income taxes; legal, regulatory, and contractual disputes and proceedings involving the Corporation, including as it pertains to establishing commercial operations at the South Hedland Power Station; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; and development projects and acquisitions, including delays in the development of the Brazeau Pumped Storage Project. The foregoing risk factors, among others, are described in further detail under the heading "Risk

Factors" in the documents incorporated by reference in this Form 40-F, including our Management's Discussion and Analysis for the year ended December 31, 2019 and the Annual Information Form for the year ended December 31, 2019.

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 the Company does 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 TransAlta has described or might not occur. TransAlta cannot assure that projected results or events will be achieved.

DOCUMENTS FILED AS PART OF THIS REPORT AND EXHIBITS

The following items are specifically incorporated by reference in, and form an integral part of, this filing on Form 40-F:

13.1	TransAlta Corporation Annual Information Form for the year ended December 31, 2019
13.2	Management's Discussion and Analysis for the year ended December 31, 2019
13.3	Consolidated Audited Annual Financial Statements for the year ended December 31, 2019
13.4	Management's Annual Report on Internal Control over Financial Reporting, (included on page F2 of Exhibit 13.3 filed herewith).
13.5	Independent Auditors' Report of Registered Public Accounting Firm, (included on page F4 of Exhibit 13.3 filed herewith).
23.1	Report of Independent Registered Public Accounting Firm.
31.1	Certification of President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of President and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data File

UNDERTAKING

TransAlta undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICES OF PROCESS

The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises and is filing contemporaneously herewith an amendment to the Form F-X to report a change in the agent for service of process. Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

EXHIBIT INDEX

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101	Interactive Data File

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSALTA CORPORATION

/s/ Todd Stack

Todd Stack
Chief Financial Officer

Dated: March 3, 2020



TRANSALTA CORPORATION

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

March 3, 2020

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form ("Annual Information Form" or "AIF") is given as at or for the year ended December 31, 2019. All dollar amounts are in Canadian dollars unless otherwise noted. Unless the context otherwise requires, all references to the "Corporation" and to "TransAlta", "we", "our" and "us" herein refer to TransAlta Corporation and its subsidiaries, including TransAlta Renewables Inc., on a consolidated basis. Reference to "TransAlta Corporation" herein refers to TransAlta Corporation, excluding its subsidiaries. Capitalized terms not defined in the body of this AIF shall have their respective meanings set forth in Appendix "B" – Glossary of Terms hereto.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

In particular, this Annual Information Form (or a document incorporated herein by reference) contains forward-looking statements including, but not limited to: our operating performance and transition to clean power generation, including our goal to have no generation from coal by the end of 2025; the conversion of our coal-fired units to natural gas and the timing thereof, the amount of capital allocated thereto and the expectations relating to shareholder returns relating to this conversion; the benefits of the clean energy investment plan, including being a low-cost generator, extending the life of the assets and reducing air emissions and costs; the source of funding for the Clean Energy Investment Plan; our expectation that the $400 million second tranche of the Brookfield investment will close in October 2020; our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2020 to 2031 and beyond; potential for growth in renewables and on-site and cogeneration assets, including the timing of commercial operation, and cost, for projects currently under development and construction; the amount of capital allocated to new growth or development projects; our business and anticipated future financial performance and anticipated results, including our outlook and performance targets; our expected success in executing on our growth and development projects; the timing and the completion of growth projects and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the terms of the current or any further proposed share buyback program and the acceptance thereof by the Toronto Stock Exchange, including the timing and number of shares to be repurchased pursuant to any normal course issuer bid; the mothballing of certain units; the impact of certain hedges on future earnings, results and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity, including for clean energy, in both the short term and long term, and the resulting impact on electricity prices; the impact of load growth, increased capacity and natural gas and other fuel costs on power prices; expectations in respect of generation availability, capacity and production; expectations regarding the role different energy sources, including renewable power generation, will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, including the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense and the adequacy of tax provisions; accounting estimates and accounting policies; anticipated growth rates and competition in our markets; our expectations relating to the outcome of existing or potential legal and contractual claims, regulatory investigations and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms or at all; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; and our credit practices.

The forward-looking statements contained in this Annual Information Form (or a document incorporated herein by reference) are based on many assumptions including, but not limited to, the following material assumptions: no significant changes to applicable laws, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the investment and credit markets; Alberta spot power prices equal $53 to $63 per MWh in

2020; Mid-C spot power prices equal to US$25 to US$35 per MWh in 2020; sustaining capital between $170 million and $200 million in 2020; our proportionate ownership of TransAlta Renewables not changing materially; no material decline in the dividends expected to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion; assumptions regarding the ability of the converted units to successfully compete in the Alberta energy-only market; and assumptions regarding our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables and being able to realize the full economic benefit from the capacity, energy and ancillary services from our Alberta hydro assets once the applicable power purchase arrangement has expired.

Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this AIF (or a document incorporated herein by reference) include, but are not limited to, risks relating to: fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; the failure of the second tranche of the Brookfield investment to close in October 2020; the outcome of pending legal proceedings described in this AIF being adverse to TransAlta, including the Brookfield investment being successfully challenged; the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic or market conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather and other climate-change related risks; unexpected increases in cost structure and disruptions in the source of fuels, water or wind required to operate our facilities; failure to meet financial expectations; natural and man-made disasters resulting in dam failures; the threat of domestic terrorism and cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, TransAlta Renewables Inc.; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks; increased costs or delays in the construction or commissioning of pipelines, or sourcing sufficient quantities of natural gas, for the converted units; changes in expectations in the payment of future dividends, including from TransAlta Renewables Inc.; insurance coverage; credit ratings; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation, including as it pertains to establishing commercial operations at the South Hedland facility; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; and development projects and acquisitions. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in this Annual Information Form or in a document incorporated herein by reference, including our management's discussion and analysis for the year ended December 31, 2019 (the "Annual MD&A").

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

DOCUMENTS INCORPORATED BY REFERENCE

TransAlta's audited consolidated financial statements for the year ended December 31, 2019, and related annual management's discussion and analysis are hereby specifically incorporated by reference in this AIF. Copies of these documents are available on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

CORPORATE STRUCTURE

Name and Incorporation

TransAlta Corporation is a corporation organized under the *Canada Business Corporations Act* (the "CBCA"). It was formed by Certificate of Amalgamation issued on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving TransAlta Corporation and TransAlta Utilities Corporation ("TransAlta Utilities" or "TAU") under the CBCA. The plan of arrangement, which was approved by shareholders on November 26, 1992, resulted in common shareholders of TransAlta Utilities exchanging their common

shares for shares of TransAlta Corporation on a one-for-one basis. Upon completion of the arrangement, TransAlta Utilities became a wholly owned subsidiary of TransAlta Corporation.

Effective January 1, 2009, TransAlta completed a reorganization, whereby the assets and business affairs of TAU and TransAlta Energy Corporation ("TransAlta Energy" or "TEC") (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a then new Alberta general partnership, whose partners are TransAlta Corporation and TransAlta Generation Ltd., a wholly owned subsidiary of TransAlta Corporation. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of a partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC and Keephills 3 GP Ltd. pursuant to the provisions of the CBCA.

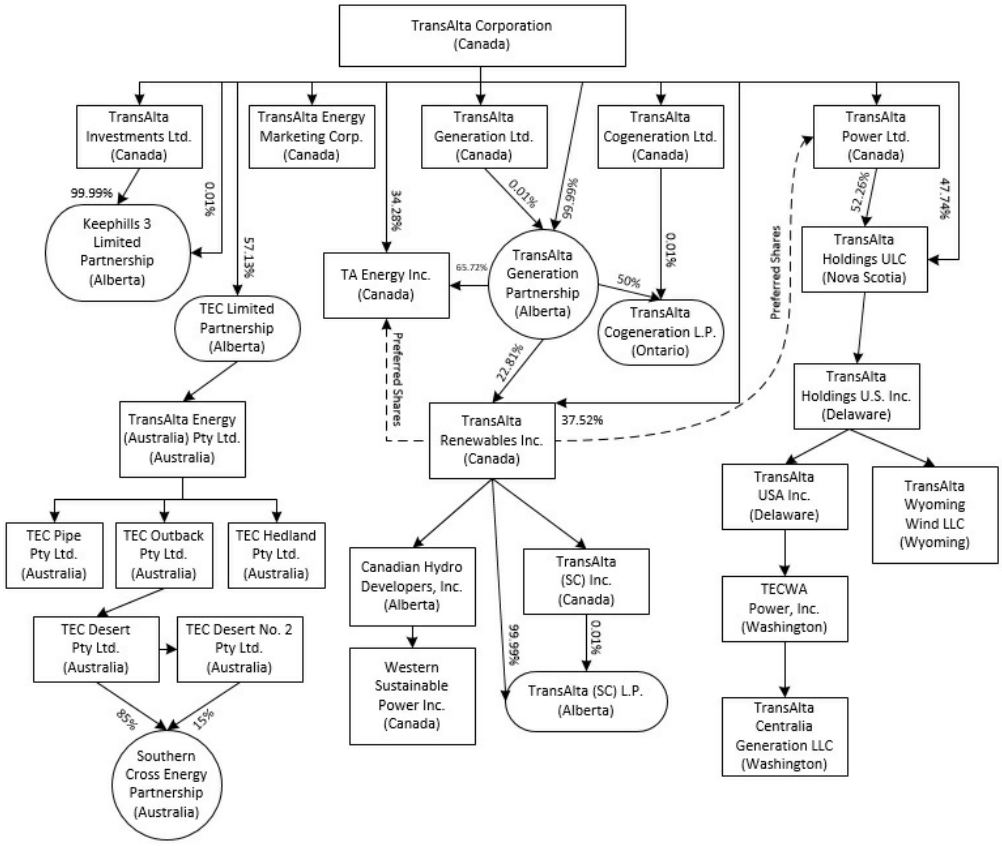
TransAlta amended its articles on December 7, 2010, to create the Series A Shares and Series B Shares; again on November 23, 2011, to create the Series C Shares and Series D Shares; again on August 3, 2012, to create the Series E Shares and Series F Shares; and again on August 13, 2014, to create the Series G Shares and Series H Shares. TransAlta expects to amend its articles in 2020 in order to create the new series of redeemable, retractable first preferred shares to be issued to an affiliate of Brookfield Renewable Partners ("Brookfield") at a second closing expected to occur in October 2020, the terms of which series of preferred shares were previously agreed upon with Brookfield. See "*Capital and Loan Structure - Exchangeable Securities*".

The registered and head office of TransAlta is located at 110 - 12th Avenue S.W., Calgary, Alberta, Canada, T2R 0G7.

Our Subsidiaries

As at the date of this AIF, the principal subsidiaries of TransAlta Corporation and their respective jurisdictions of formation are set out below.

Certain of our subsidiaries are not wholly owned. The most significant subsidiary is TransAlta Renewables Inc. ("TransAlta Renewables"), which completed its initial public offering in August 2013. In connection with the offering, TransAlta Corporation transferred to TransAlta Renewables certain wind and hydro power generation assets previously held directly or indirectly by TransAlta Corporation. As at December 31, 2019, TransAlta Corporation owned, directly or indirectly, approximately 60 per cent of the outstanding voting equity in TransAlta Renewables. See "*Business of TransAlta – Non-Controlling Interests – TransAlta Renewables*".



Notes:

(1) Unless otherwise stated, ownership is 100 per cent. As noted elsewhere in this AIF, TransAlta Renewables has economic interests in a number of projects through tracking preferred shares in the capital of TA Energy Inc. and TransAlta Power Ltd., which are both wholly owned by TransAlta Corporation.

(2) We own, directly or indirectly, an aggregate interest of approximately 60 per cent of TransAlta Renewables, which includes 37.52 per cent through direct ownership and 22.81 per cent through TransAlta Generation Partnership. The remaining approximately 40 per cent interest in TransAlta Renewables is publicly owned.

OVERVIEW

TransAlta

We are a leading provider of renewable and thermal-based energy with a 108-year history of powering economies and communities, safely, reliably and sustainably. Our vision is to be a global leader in clean energy with a commitment to a sustainable future. Our mission is to deliver to our customers power and power solutions that provide safe, low-cost and reliable clean energy. We apply our expertise, scale, and diversified fuel mix to capitalize on opportunities in our core markets and grow in areas where our competitive advantages can be deployed.

As we look to transition towards a more sustainable future, our values are grounded in safety, innovation, sustainability, respect and integrity, all of which enable us to work towards our common goals. These values are the principles that define our corporate culture. They reflect our skills and mindset, while providing a framework for everything we do, guiding both internal conduct and external relationships. These values are at the heart of our success.

- Safety – We are committed to the health and safety of our people and those with whom we work.
- Innovation – TransAlta has been a leader in clean electricity for over a century and will continue to be for the next century. Our goal is to continue to be a leader in clean electricity by finding new and innovative ways to power economies and communities.
- Sustainability – A strong business is only possible within a strong and equitable ecosystem.
- Respect – We value the perspectives and experiences of one another. Respect in the workplace and within our working relationships is paramount.
- Integrity – This is the foundation of our business. We always act with honesty, fairness and transparency. Our commitment is to do what we say we will do.

TransAlta and its predecessors have been engaged in the development, production and sale of electric energy since 1911. We are among Canada's largest non-regulated electricity generation and energy marketing companies with an aggregate net ownership interest in approximately 8,051 megawatts ("MW") of generating capacity. We operate facilities having approximately 8,978 MW of aggregate generating capacity. We are focused on generating and marketing electricity in Canada, the United States and Western Australia through our diversified portfolio of facilities fuelled by coal, natural gas, diesel, hydro, wind and solar.

TransAlta's diversified portfolio of power-generating assets across multiple geographies, technologies and mix of merchant and contracted assets provides cash flows that support our ability to pay dividends to our shareholders, reinvest in growth and fund sustaining and capital expenditures.

Corporate Strategy

Our strategic focus is to invest in a disciplined manner in a range of clean and renewable technologies such as wind, hydro, solar, battery and thermal (natural gas-fired and cogeneration) that produce electricity for industrial customers and communities to deliver returns to our shareholders.

On September 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017. TransAlta is currently pursuing growth opportunities of $1.8 billion to $2.0 billion as part of this plan, including approximately $800 million of renewable energy projects either recently completed or already under construction. The implementation and execution of TransAlta's Clean Energy Investment Plan, including the acceleration of certain features of that plan, is in large part being facilitated by the $750 million strategic investment by Brookfield that we announced in March 2019 in response to feedback received from our shareholders during extensive engagement held in 2018 and 2019. The first $350 million tranche of Brookfield's investment closed in May 2019 and facilitated the acceleration of our coal-to-gas conversion plan discussed below. The second $400 million tranche of Brookfield's investment, anticipated to close in October 2020, will help further the advancement and implementation of the remainder of our Clean Energy Investment Plan, including our expected growth in renewables, while helping the Corporation maintain a strong balance sheet and financial flexibility to carry out the other pillars of our strategy discussed below.

On Jan. 16, 2020, TransAlta announced near-term objectives that further support the Clean Energy Investment Plan. In addition, we announced our 2020 sustainability targets.

Our strategic priorities are focused on the following outcomes:

1. Successfully execute our coal-to-gas conversions

We are transitioning our Alberta thermal fleet to natural gas, as part of our Clean Energy Investment Plan. We plan to invest between $800 million to $1.0 billion to convert or repower our Alberta thermal fleet to natural gas. This will repurpose and reposition our fleet to a cleaner gas-fired fleet and advance our leadership position in on-site generation while generating attractive returns by leveraging the Corporation's existing infrastructure.

TransAlta's Clean Energy Investment Plan includes converting three of our existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The cost to convert each unit is expected to be approximately $30 to $35 million per unit.

The Clean Energy Investment Plan also includes permitting to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined-cycle facility while achieving a similar heat rate. The Clean Energy Investment Plan assumes there are no delays in securing the natural gas supply requirements, which may result from regulatory or other constraints.

The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of our Alberta thermal assets; and
- Significantly reducing air emissions and costs.

The following key achievements over the past year helped us advance this part of our strategy:

On December 17, 2018, the Corporation exercised our option to acquire 50 per cent ownership in the Pioneer gas pipeline (the "Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on November 1, 2019. Tidewater Midstream and Infrastructure Ltd. ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, was approximately $100 million.

In 2019, we issued Full Notice to Proceed ("FNTP") to convert Sundance Unit 6 and Keephills Unit 2 to natural gas by replacing the existing coal burners with natural gas burners. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020 and Keephills Unit 2 by the first half of 2021.

We expect to issue Limited Notice to Proceed ("LNTP") for Keephills Unit 3 during the first half of 2020 and expect to complete the conversion of that unit during 2021. We are evaluating the potential to install dual fuel capability at Keephills Unit 3 to ensure we have optimal fuel flexibility as we transition the fleet from coal to gas, and to manage any timing delays in obtaining full gas requirements that may occur due to regulatory or other constraints.

We are currently seeking regulatory permits to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined- cycle facility while achieving a similar heat rate.

To advance this repowering strategy, on October 30, 2019, TransAlta acquired two 230 MW Siemens F-class gas turbines and related equipment for $84 million. These turbines will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. We expect to issue LNTP in 2020 and FNTP in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined- cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million, well below a greenfield combined-cycle project. In conjunction with the Sundance Unit 5 permitting, we are also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined-cycle unit, depending on market fundamentals. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of greenhouse gas ("GHG") costs, starting in late 2023 with Shell Energy North America (Canada).

2. Deliver growth in our renewables fleet

We are further expanding our renewables platform. We currently have over $400 million of renewable energy construction projects to be completed in 2020 and 2021. We completed and commissioned two wind farms in 2019 investing over $340 million through TransAlta Renewables. Our focus is to ensure that we solidify returns through exceptional project execution and integration where we are able to commission and operate assets within our schedule and cost objectives.

The following key achievements in 2019 helped us advance this part of our strategy:

US Wind Projects

In 2019, we completed the construction of two wind projects (collectively, the "US Wind Projects") in the Northeastern US. The Big Level wind project ("Big Level") acquired on March 1, 2018, consists of a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. The Antrim wind project ("Antrim") acquired on Mar. 28, 2019 consists of a 29 MW project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. Big Level and Antrim began commercial operations on Dec. 19, 2019, and Dec. 24, 2019, respectively. The US Wind Projects have added an additional 119 MW of generating capacity to our Wind and Solar portfolio.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs.

Windrise Wind Project

On December 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the Alberta Electric System Operator ("AESO") as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta, and is expected to cost approximately $270 million to $285 million. The project development work is on schedule. Windrise has secured approval for the facility from the Alberta Utilities Commission ("AUC") and is currently permitting transmission lines required to connect the facility to the Alberta grid. Construction activities will start in the second quarter of 2020 and the project is on track to reach commercial operation during the first half of 2021.

Skookumchuck Wind Project

On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind project, a 136.8 MW wind project currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy. TransAlta has the option to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be approximately $150 million to $160 million, a portion of which is expected to be funded with tax equity financing.

WindCharger Project

During the first quarter of 2019, TransAlta approved the WindCharger project, an innovative energy storage project, which will have a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview Wind Farm Substation. WindCharger will store energy produced by the nearby Summerview II Wind Farm and discharge into the Alberta electricity grid at times of peak demand. This project is expected to be the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the AUC and an interconnection application to the AESO, were submitted in 2019. AUC approval was granted in November 2019 and the AESO approval is expected by the end of the first quarter of 2020. Detailed engineering designs, as well as the procurement of long-lead equipment, has been completed. Construction is on track to begin in March 2020 with a commercial operation date expected within the second quarter of 2020. The total expected cost of the project to TransAlta is $7 million to $8 million.

3. Expand presence in the US renewables market

We are focusing our business development efforts in the renewables segment of the US market. Demand for new renewables in the US is expected to grow in the near term. We currently have 2,000 MW at different stages in our development pipeline. These opportunities are expected to grow TransAlta Renewables, utilize its excess debt capacity and deliver stable dividends back to TransAlta.

In addition to the US Wind Projects and the Skookumchuck wind project discussed above, during 2019, TransAlta acquired a portfolio of wind development projects in the US. If we decide to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025. If a decision is made to not move forward with a project or the costs are no longer considered to be recoverable, the costs are charged to earnings. Estimated returns on these projects and similar projects are sufficient to recover costs of unsuccessful development projects.

4. Advance and expand our on-site generation and cogeneration business

We will grow our on-site and cogeneration asset base, a business segment we have deep experience in, having provided on-site cogeneration services to various customers since the early 1990s. Our current pipeline under evaluation is approximately 900 MW and our technical design, operations experience and safety culture make us a strong partner in this segment. We see this segment growing as industrial and large-scale customers are looking to find solutions to help lower costs of power production, replace aging or inefficient equipment, reduce network costs and meet their ESG objectives.

Consistent with this strategy, on October 1, 2019, TransAlta and SemCAMS announced that they entered into definitive agreements to develop, construct and operate a cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

The highly efficient cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights. The development of the cogeneration facility at Kaybob South No. 3 is expected to eliminate the need for traditional boilers and reduce annual carbon emissions of the operation by approximately 100,000 tonnes carbon dioxide equivalent ("CO_2e"), which is equivalent to removing 20,000 vehicles off Alberta roads.

5. Maintain a strong financial position

We intend to remain disciplined in our capital investment strategy and continue to build on our already strong financial position.

We currently have access to $1.7 billion in liquidity, including $411 million in cash. During 2019, we entered into transactions to strengthen our position to execute on the Clean Energy Investment Plan including: (i) entering into an investment agreement with Brookfield providing us with $750 million in strategic financing, (ii) increasing our credit facilities by $200 million to a total of $2.2 billion and extending the maturity of the term by one year, and (iii) successfully obtaining US$126 million of tax equity financing associated with the US Wind Projects.

To further this strategy in 2020, we will repay the $400 million bond maturing in November 2020 and continue our share buyback program in an amount up to $80 million.

The Clean Energy Investment Plan will be funded from the cash raised through the strategic investment by Brookfield, cash generated from operations and raising capital through TransAlta Renewables.

In addition, we continue to execute on our multi-year Greenlight program that is focused on transforming our business and delivering TransAlta's strategy by reducing our cost structure. The program is entering its fourth year since implementation, and with each passing year it creates a continuous improvement culture that improves the way employees work together to deliver better business results. The program is focused on creating a structure around our people that enables them to identify, develop and deliver projects that improve performance across the Corporation with an emphasis on delivering sustainable value and cash flow improvements. Through the program, we have instituted ways to optimize our assets, minimize GHG emissions, reduce capital and operating costs, improve fuel usage and streamline processes. As this approach is increasingly embedded into the Corporation it has increased the empowerment of our employees, strengthened our processes and improved our corporate culture while reducing our operating costs.

Our Environmental, Social and Governance Leadership

Sustainability means ensuring that our financial returns consider short- and long-term economics, environmental impacts and societal and community needs. As we execute our strategy, our decisions are governed with a view to

also deliver on our ESG objectives. We have a long history of adopting leading sustainability practices, including 25 years of sustainability reporting and voluntarily integrating our sustainability report into our annual report. We have been issuing an integrated annual report since 2015. We test our practices and our reporting against standards set by CDP (formerly the Carbon Disclosure Project), the Task Force on Climate-related Financial Disclosures and the Canadian Council for Aboriginal Business. We have received a number of ESG rankings and recognition as a result of our early adoption of ESG practices.

In 1990, we were the first Canadian company to purchase carbon offsets and in 2000 we were an early adopter of wind power generation. Through our ongoing transformational efforts, we have reduced our total GHG emissions by 21.3 million tonnes since 2005. Our goal is to have no generation fuelled by coal by the end of 2025. The Corporation aligns its ESG targets with the UN Sustainable Development Goals.

The key components of our Corporation's approved 2020 ESG targets include:

- a continued focus on safe operations and environmentally sustainable practices, including minimizing environmental incidents and undertaking significant reclamation work;
- by 2030, achieving a 95% reduction in sulphur dioxide emissions and a 50% reduction of nitrogen oxide ("NOx") emissions over 2005 levels from our coal facilities, and a company-wide reduction in GHG emissions of 60% below 2015 levels;
- undertaking initiatives that will enhance the environmental performance of the Corporation, including converting coal facilities to natural gas and developing new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions;
- supporting equal access to all levels of education for youth and Indigenous peoples through financial assistance and employment opportunities;
- enhancing our commitment to workplace gender diversity, including adopting a target of 50 per cent representation of women on the Board by 2030 and at least 40 per cent representation of women among all of our employees by 2030; and
- maintaining our commitment to leading ESG disclosures.

Our Capital Allocation and Financing Strategy

Our goal is to remain disciplined with our capital investment program and ensure that we continue to enhance our financial position. We are focused on strengthening our financial position and cash flow coverage ratios to ensure that a strong balance sheet is maintained and sufficient capital is available to execute our strategy.

Our goal is to return our deconsolidated debt levels to below a 3.0x debt-to-EBITDA ratio and to continue to pay and grow our dividend. We have adopted a debt-to-EBITDA target range of between 2.5 to 3.0x, based on TransAlta deconsolidated funds from operations.

We have also committed to a capital allocation program that provides investors with a line of sight on how we would consider changes into the future and provide further transparency on how the dividends that we receive from our ownership in TransAlta Renewables are either being returned to shareholders or reinvested at TransAlta. The Board adopted a dividend policy of returning between 10 per cent and 15 per cent of TransAlta deconsolidated funds from operations to common shareholders. In addition to the dividend, both on common and preferred shares, between 25 per cent to 35 per cent of capital is allocated towards sustaining and productivity capital, which ensures our existing assets continue to operate as efficiently as possible. Also included in our capital allocation program is to fund regular repayments on our amortizing debt. Once all of these items are considered, between 30 per cent to 50 per cent of deconsolidated funds from operations remain for the Corporation to allocate to growth projects, further debt reductions or to buy back shares.

We are confident that the above program balances the demands associated with meeting our goals around reinvestment, new growth and debt repayments along with providing shareholders a return on their capital.

Our Business Segments

The Canadian Coal segment has a net ownership interest of approximately 3,032 MW of owned electrical generating capacity as well as our interest in the Pioneer Pipeline (discussed further below). The Pioneer Pipeline and all of the facilities in this segment are located in Alberta.

The US Coal segment holds our Centralia thermal plant, which represents a net ownership interest of 1,340 MW of owned electrical generating capacity. One of the units, which represents half of the facility's generating capacity, is scheduled to retire at the end of 2020. The Centralia plant is located in the State of Washington.

The Hydro segment has a net ownership interest of approximately 926 MW of owned electrical generating capacity. The facilities within this segment are predominantly located in Alberta, British Columbia, and Ontario.

The Wind and Solar segment has a net ownership interest of approximately 1,467 MW of owned electrical generating capacity and includes facilities located in Alberta, Ontario, New Brunswick, Québec, and the states of Massachusetts, Minnesota, New Hampshire, Pennsylvania and Wyoming.

The Canadian Gas segment has a net ownership interest of approximately 837 MW of owned electrical generating capacity and includes facilities held in Alberta and Ontario.

The Australian Gas segment has a net ownership interest of approximately 450 MW of owned electrical generating capacity and a pipeline located in Western Australia.

The Energy Marketing segment is responsible for marketing our production through short-term and long-term contracts, for securing cost effective and reliable fuel supply, and for maximizing margins by optimizing our assets as market conditions change. Our Energy Marketing segment is actively engaged in the trading of power, natural gas and environmental products across a variety of markets.

The Corporate segment supports each of the above segments and includes the Corporation's central finance, legal, administrative, business development and investor relation functions.

We regularly review our operations in order to optimize our generating assets and evaluate appropriate growth opportunities to maximize value to the Corporation. We have in the past made, and may in the future make, changes and additions to our fleet of coal, natural gas, hydro, wind and solar facilities.

TransAlta Renewables

TransAlta Corporation is the majority owner of TransAlta Renewables, with an approximate 60 per cent direct and indirect ownership interest as of the date of this Annual Information Form. TransAlta Renewables is one of the largest generators of wind power and among the largest publicly traded renewable power generation companies in Canada.

We formed TransAlta Renewables in 2013 to realize specific strategic and financial benefits, including: (i) establishing a focused vehicle for pursuing and funding growth opportunities in the renewable power and gas generation sector; (ii) unlocking the value of TransAlta's renewable asset platform; (iii) retaining TransAlta's majority ownership and operatorship of the underlying assets; (iv) providing proceeds of approximately $200-$250 million to repay debt and support TransAlta's balance sheet; and (v) creating additional financial flexibility for TransAlta by providing another source of capital with a separate cost of capital. We continue to realize the benefit of having assets with different risk/return profiles in two separate corporations as it enables each company to secure appropriate financing and investors. TransAlta holds mainly merchant assets in coal and hydro while TransAlta Renewables holds assets with long-term contracts generating stable cash flows in wind, solar and gas. TransAlta's majority ownership of TransAlta Renewables has facilitated the Corporation in its overall strategy of developing, constructing or acquiring additional renewable assets.

TransAlta Renewables, or one or more of its wholly owned subsidiaries, directly own certain of our wind, hydro and natural gas facilities. TransAlta Renewables also owns economic interests in a number of our other facilities. TransAlta Corporation provides all management, administrative and operational services required for TransAlta Renewables to operate and administer its assets and to acquire additional assets pursuant to the Management and Operational Services Agreement and the Governance and Cooperation Agreement between TransAlta Corporation and TransAlta Renewables. See "*Business of TransAlta – Non-Controlling Interests – TransAlta Renewables*".

TransAlta's Map of Operations

The following map outlines TransAlta's operations as of December 31, 2019.



Note:

(1) Includes facilities directly owned by TransAlta Renewables or its subsidiaries, as well as facilities in which TransAlta Renewables or one of its subsidiaries has an economic interest. We own, directly or indirectly, an aggregate interest of approximately 60 per cent of TransAlta Renewables.

GENERAL DEVELOPMENT OF THE BUSINESS

TransAlta is organized into eight business segments: Canadian Coal, US Coal, Canadian Gas, Australian Gas, Wind and Solar, Hydro, Energy Marketing and Corporate. The Canadian Coal, US Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro segments are responsible for operating and maintaining our electrical generation and associated operations.

The Canadian Coal segment is also responsible for the operation and maintenance of our related mining operations and the operation of the Pioneer Pipeline in Alberta.

The Energy Marketing segment is responsible for marketing our production through short-term and long-term contracts, for securing cost effective and reliable fuel supply, and for maximizing margins by optimizing our assets as market conditions change. In addition to serving our assets, our marketing team actively markets energy products and services to energy producers and customers. This segment also encompasses the management of available generating capacity as well as the fuel and transmission needs of the generation businesses.

All the segments are supported by a Corporate segment, which includes the Corporation's central financial, legal, administrative, business development and investor relations functions.

Significant regulatory changes continue to have extensive impacts on the Corporation's business and strategy. In 2015, the Government of Alberta announced the Alberta Climate Leadership Plan that set goals to reduce carbon emissions and phase out pollution from coal-generated electricity by 2030. TransAlta responded quickly to this announcement and set down the path to fully transform itself into a leading clean energy company. Part of this strategy was to fully convert our existing coal fleet to natural gas, and our goal is to have no generation from coal by the end of 2025. In addition, we continue to expand our renewable generation and cogeneration fleet with numerous wind and gas projects currently under development. Throughout this transformation, we always keep our mission statement in mind: to provide safe, low-cost and reliable clean electricity to consumers and communities.

The significant events and conditions affecting our business during the three most recently completed financial years, and during the current year to date, are summarized below. Certain of these events and conditions are discussed in greater detail under the heading "*Business of TransAlta*".

Three-Year History

Generation and Business Development

2020

TransAlta Renewables Inc. Delivers on Two Contracted US Wind Projects

TransAlta Renewables announced on January 7, 2020, that the Big Level wind farm and the Antrim wind farm began commercial operation on December 19, 2019, and December 24, 2019, respectively. TransAlta Renewables has an economic interest in these two US wind farms, The 90 MW Big Level wind farm located in Pennsylvania is under a 15-year contract with Microsoft and the 29 MW Antrim wind farm located in New Hampshire is under two 20-year contracts with Partners Healthcare and New Hampshire Electric Co-op, respectively. All counterparties have a Standard & Poor’s credit rating of A+ or better.

During the third quarter of 2019, subsidiaries of TransAlta entered into final agreements with an external party for a planned tax equity investment in the Antrim and Big Level wind farms. In December 2019, following Antrim and Big Level each achieving commercial operation, approximately $166 million (US$126 million) of tax equity proceeds were raised by the TransAlta project entities to partially fund the Antrim and Big Level wind farms, for US$41 million and US$85 million, respectively. The tax equity financing is classified as long-term debt on the statement of financial position.

TransAlta Renewables, through its economic interest ownership, provided construction funding with a combination of tracking preferred shares and interest-bearing notes issued by the project entity. The tax equity proceeds will be used to repay TransAlta Renewables the principal and accrued interest outstanding on the interest-bearing promissory notes utilized to fund the construction.

2019

Advancing our Clean Energy Investment Plan

In 2019, we announced our Clean Energy Investment Plan, which included plans to convert our existing Alberta coal assets to natural gas and advance our leadership position in on-site generation and renewable energy.

TransAlta's initial plan included converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The cost to convert is estimated to be approximately $30 million to $35 million per unit.

The Corporation also advanced permitting to repower one, or possibly two, of its units to highly efficient combined cycle natural gas units. The highlights of these gas conversion investments include:

- positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- generating attractive returns by leveraging the Corporation's existing infrastructure;
- significantly extending the life and cash flows of the Alberta thermal assets; and
- significantly reducing air emissions and costs.

The Corporation's Clean Energy Investment Plan also includes the Big Level and Antrim wind projects that were completed in December 2019, the Windrise and Skookumchuck wind projects that are currently under construction, and a cogeneration facility also under construction. These projects are underpinned by long-term PPAs with highly creditworthy counterparties. In addition, the Corporation is advancing the Windcharger project, an innovative battery storage project at one of its existing wind sites.

The Clean Energy Investment Plan will be funded from the cash raised in 2019 through the strategic investment with Brookfield (discussed further below), cash generated from operations, and raising capital through TransAlta Renewables.

As part of this Clean Energy Investment Plan, we are permitting to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined cycle facility while achieving a similar heat rate. The plan assumes there are no delays in securing the natural gas supply requirements, which may result from regulatory or other constraints.

On October 30, 2019, we acquired two 230 MW Siemens F class gas turbines and related equipment for $84 million. These turbines will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. We expect to issue Limited Notice To Proceed ("LNTP") in 2020 and Full Notice To Proceed ("FNTP") in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million, well below a greenfield combined cycle project. In conjunction with the Sundance Unit 5 permitting, we are also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined cycle unit, depending on market fundamentals. In addition, we assumed a long-term power purchase agreements for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada).

Kaybob Generation Project

On October 1, 2019, we announced, together with SemCAMS Midstream ULC ("SemCAMS"), a subsidiary of SemGroup Corporation, that we had entered into definitive agreements to develop, construct and operate a cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. We will construct the cogeneration plant which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a fifty per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

The highly efficient cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta Power market by TransAlta. The agreement contemplates an automatic 7-year extension subject to certain termination rights. The development of the cogeneration facility is expected to eliminate the need for traditional boilers and reduce annual carbon emissions at the operation by approximately 100,000 tonnes CO2e which is equivalent to removing 20,000 vehicles off Alberta roads.

Agreement to Swap Non-Operating Interests in Keephills 3 and Genesee 3

On August 2, 2019, we entered into definitive agreements with Capital Power Corporation ("Capital Power") providing for the swap of our respective non-operating interests in the Keephills 3 facility and the Genesee 3 facility. On October 1, 2019, we closed the transaction with Capital Power. As a result, we own 100% of the Keephills 3 facility and Capital Power owns 100% of the Genesee 3 facility. The transaction price for each non-operating interest largely offset each

other, resulting in a net payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

Continued Energy-Only Market in Alberta

On July 25, 2019, we commented on the Government of Alberta's announcement that the energy-only market framework in Alberta will be maintained. The promise by the Alberta government to deliver a decision on market structure within 90 days was fulfilled and reduced the significant uncertainty for TransAlta in assessing investment decisions in power generation in the Alberta market. We undertook a review of our future investment decisions on coal-to-gas conversions and repowering investments, as well as impacts on hydro and wind assets under an energy-only market. The review concluded our current strategy is the best path forward under any market design and we continue to progress with our conversion strategy.

The energy-only market has been in place in Alberta since 2000. The structure ensures a competitive framework that is reliable for forecasting and assessing risk against major investments.

Favourable Keephills 1 Force Majeure Ruling

On June 26, 2019, the Court of Queen's Bench in Alberta upheld the decision of an independent arbitration panel, which confirmed that we were entitled to force majeure relief for the 2013 Keephills 1 forced outage. Our 395 MW Keephills 1 facility tripped off-line on March 5, 2013 due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined a full rewind of the generator stator was required. The unit returned to service on October 6, 2013. On November 13, 2019, the buyer under this power purchase arrangement and the Balancing Pool sought permission from the Alberta Court of Appeal to appeal the Court of Queen's Bench decision. Permission was granted on February 13, 2020. TransAlta will continue to defend the arbitration award, with the appeal application before the Alberta Court of Appeal likely scheduled for the fall of 2020.

Skookumchuck Wind Project

On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind energy facility located in Lewis and Thurston counties near Centralia in the State of Washington. This is 136.8 MW wind facility currently under construction. The project has a 20-year PPA with Puget Sound Energy. TransAlta expects to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be approximately $150 to $160 million, a portion of which is expected to be funded with tax equity financing.

Strategic Investment by Brookfield Renewable Partners

On March 25, 2019, we announced a strategic investment by Brookfield that crystallizes the future value of our Hydro Assets, enhances our financial position to execute our strategy, accelerates the opportunity to return capital to shareholders and provides TransAlta with a partner who has world-class expertise in renewable power platforms and hydroelectric generation . This investment ensures TransAlta will transition to 100 per cent clean energy by 2025.

Under the terms of an investment agreement (the "Investment Agreement"), Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities (described below), which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA. In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to 9%. We are working to complete our transition to clean energy, maximize the value of the Hydro Assets, and create long-term shareholder value. On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for 7% unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to certain conditions being met.

Benefits of the investment are highlighted below:

- significant $750 million capital injection which will be used to advance our coal-to-gas transition strategy, advance the development of existing and new growth projects and for general corporate purposes;
- recognizes the future anticipated value of our Hydro Assets;
- creates a long-term cornerstone shareholder;
- strengthens our operating capabilities;
- accelerates the return of capital to shareholders through share buy backs; and
- adds extensive renewables experience and expertise by electing two experienced Brookfield directors, Harry Goldgut and Richard Legault to our Board of Directors.

Additional details about the Brookfield investment can be found in our material change report dated March 26, 2019, available electronically on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. Copies of the Investment Agreement, together with copies of the exchangeable debenture issued to Brookfield on May 1, 2019, the registration rights agreement entered into with Brookfield in respect of common shares held in TransAlta, and the exchange and option agreement with Brookfield governing the terms of the exchange of the exchangeable securities issued under the investment, are also available on SEDAR and on EDGAR. Shareholders are urged to read these documents in their entirety.

Extended Mothballing of Sundance Unit 3 and Unit 5

On March 8, 2019, we announced that the AESO granted the extension of the mothballing for the below Sundance Units:

- Sundance Unit 3 will remain mothballed until November 1, 2021, extended from the previous date of April 1, 2020; and
- Sundance Unit 5 will remain mothballed until November 1, 2021, extended from the previous date of April 1, 2020.

The extensions were requested by us based on the Corporation's assessment of market prices and market conditions. We can return either of the units back to full operation by providing three months' notice to the AESO.

2018

Pioneer Pipeline

On December 17, 2018, we exercised our option to acquire 50 per cent ownership in the Pioneer Pipeline. During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to our generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas commenced flowing through the Pioneer Pipeline on November 1, 2019. Tidewater Midstream and Infrastructure Ltd. ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The pipeline investment, including associated infrastructure, was approximately $100 million.

Alberta Renewable Energy Program Project – Windrise

On December 17, 2018, our 207 MW Windrise wind project was selected by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta and is expected to cost approximately $270 million to $285 million. The project development work is on schedule on track to reach commercial operation during the first half of 2021.

TransAlta Renewables' New Brunswick wind power expansion complete

On October 19, 2018 TransAlta Renewables announced that the 17.25MW expansion of the wind facility at Kent Hills, in New Brunswick reached commercial operation, bringing total generating capacity to 167 MW. Under the 17-year PPA, New Brunswick Power Corporation receives both energy to the province's electricity grid and renewable energy credits ("RECs"). The Kent Hills 3 expansion is located on approximately 20 acres of Crown Land and consists of five Vestas V126 turbines. Natural Forces Technologies Inc., a wind-energy developer based in Atlantic Canada, co-developed and co-owns the wind farm with TransAlta Renewables.

Retirement of Sundance Unit 1 and Unit 2 and Mothball Schedule Update

Effective July 31, 2018, we retired Sundance Unit 2 due to its shorter useful life relative to other units, age, size, and the capital requirements needed to return the unit to service. In addition to the retirement of Sundance Unit 2 our mothball outage schedule had been updated to provide for the following (Sundance Unit 1 has been permanently shutdown since January 1, 2018 and Sundance Unit 3 and Sundance Unit 5 have been mothballed since April 1, 2018): (i) Sundance Unit 3 will continue to be mothballed up to November 1, 2021 (extended from the previous date of April 1, 2020); and (ii) Sundance Unit 5 will continue to be mothballed up to November 1, 2021 (extended from the previous date of April 1, 2020).

Sale of Three Renewable Assets

On May 31, 2018, TransAlta Renewables acquired from us an economic interest in the 50 MW Lakeswind Wind Farm in Minnesota and 21 MW of solar projects located in Massachusetts. In addition, TransAlta Renewables acquired ownership of the 20 MW Kent Breeze Wind Farm located in Ontario. The total purchase price payable for the three

assets, which had an average weighted contract life of 15 years, was $166 million, including the assumption by TransAlta Renewables of $62 million of tax equity obligations and project debt. TransAlta Renewables funded the equity portion of the acquisitions using its existing liquidity. On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million (US$25 million) of tracking preferred shares of a subsidiary of TransAlta, in order to fund the repayment of Mass Solar's project debt.

Acquisition of US Wind Projects

On February 20, 2018, TransAlta Renewables entered into an arrangement to acquire economic interests in the Big Level and Antrim wind farms. On February 28, 2018 TransAlta Renewables acquired tracking preferred shares from the Corporation that provide TransAlta Renewables with an economic interest in the Big Level and Antrim wind farms. The Big Level and Antrim wind farms began commercial operation on December 19, 2019 and December 24, 2019, respectively. See "*- 2020 - TransAlta Renewables Inc. Delivers on Two Contracted US Wind Projects.*"

2017

Acceleration of the Conversion from Coal-to-Gas

On December 6, 2017, we announced the acceleration of the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in 2021 or 2022, a year earlier than originally planned. We also announced the temporary mothballing of a combination of Sundance units in 2018 and 2019 to enable two Sundance coal units to operate at high capacity utilizations with lower costs through to 2020.

Status of Commercial Operations at South Hedland Facility

On August 1, 2017, we responded to Fortescue Metals Group Ltd.'s ("FMG") view that the South Hedland facility has not yet achieved commercial operation. In our view, all the conditions to establishing that commercial operations have been achieved under the terms of the power purchase agreement with FMG have been satisfied in full. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. On November 13, 2017, we received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from FMG. We commenced proceedings in the Supreme Court of Western Australia on December 4, 2017, to recover amounts invoiced under the South Hedland PPA. The South Hedland facility has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017. See "*Legal Proceedings and Regulatory Actions*" for further information.

Fortescue Metals Group's Notice to Repurchase the Solomon Facility

On August 1, 2017, we received notice of FMG's intention to repurchase the Solomon facility from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly-owned subsidiary of the Corporation, for approximately US$335 million. A dispute does exist between TransAlta and FMG related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

Sale of Interest in Wintering Hills Facility

On March 1, 2017, we sold our 51 per cent interest in the Wintering Hills merchant wind facility near Drumheller, Alberta for approximately $61 million. Proceeds from the sale were used for general corporate purposes, including to reduce debt and to fund future renewables growth, including potential contracted renewable opportunities in Alberta.

Corporate and Energy Marketing

2020

TransAlta Declares Increased Common Dividend and Appoints John P. Dielwart as the next Chair of the Board

We announced that the Board of Directors determined that following the retirement of Ambassador Gordon D. Giffin at the 2020 annual shareholder meeting, John P. Dielwart will be appointed successor Chair of the Board effective immediately following our 2020 annual meeting of shareholders and subject to him being re-elected to the Board at the 2020 meeting.

In addition, we declared an increase in the annualized dividend to $0.17 per common share, representing a 6.25 per cent increase.

2019

Favourable Conclusion Regarding the Sundance B and C Power Purchase Arrangements Termination Payment

On August 26, 2019, we announced that we were successful in our arbitration with the Balancing Pool for the remaining payment related to the termination of the Sundance B and C Power Purchase Arrangements ("PPA"). As a result of the arbitration decision, we received the full amount we had been seeking to recover, being equal to $56 million, plus GST and interest from the Balancing Pool. This payment related to TransAlta's historical investments in certain mining and corporate assets that the we believed should have been included in the net book value calculation of the PPAs that had been disputed by the Balancing Pool.

Normal Course Issuer Bid

On May 27, 2019, the Toronto Stock Exchange ("TSX") accepted our notice to implement a normal course issuer bid ("NCIB"). Pursuant to the NCIB, we may purchase up to a maximum of 14,000,000 of our common shares. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which our common shares are traded, based on the prevailing market price and subject to certain limitations. Any common shares purchased under the NCIB will be cancelled. For the period from May 29, 2019 to March 2, 2020 we purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share for a total cost of approximately $68 million. In connection with the Brookfield investment, the Corporation committed to returning up to $250 million to our holders of common shares through share purchases.

Appointment of Chief Financial Officer

On May 16, 2019, we appointed Todd Stack as our Chief Financial Officer. Mr. Stack, who has served as Managing Director and Corporate Controller of the Corporation since February 2017, has been responsible for providing leadership and direction over TransAlta's financial activities, corporate accounting and reporting, tax, and corporate planning.

Board of Director Nominations

Concurrent with the strategic investment by Brookfield, we announced the inclusion of three experienced nominees for our slate of directors at the 2019 Annual and Special Meeting of shareholders. The nominees included Harry Goldgut, Richard Legault and Robert Flexon. All three nominees, along with all other board nominees, were elected to the Board of Directors at the Annual and Special Meeting of shareholders on April 26, 2019. Messrs. Legault and Goldgut are Brookfield's current nominees on the Board. Pursuant to the Investment Agreement with Brookfield, for so long as Brookfield owns the exchangeable securities issued to it under the Investment, it has the right to nominate two members for election to the TransAlta Board at each annual meeting of shareholders.

2018

Redemption of Medium Term Notes

On August 2, 2018 we redeemed all of our then outstanding 6.40 per cent Medium Term Notes, due November 18, 2019 in the aggregate principal amount of $400 million (the "Notes"). The redemption price for these Notes was $1,061.736 per $1,000 principal amount of the Notes (representing, in aggregate, $425 million) including a prepayment premium and accrued and unpaid interest on the Notes to the redemption date.

$345 Million Bond Offering

On July 20, 2018 our indirect wholly owned subsidiary, TransAlta OCP LP (the "TransAlta OCP"), issued approximately $345 million of bonds, sold by way of a private placement, which are secured by, among other things, a first-ranking charge over all but a nominal percentage of the equity interests in TransAlta OCP and its general partner, and a first-ranking charge over all of the TransAlta OCP's accounts and certain other assets. The amortizing bonds bear interest from their date of issue at a rate of 4.509 per cent per annum, payable semi-annually and mature on August 5, 2030.

TransAlta Renewables Completes $150 Million Bought Deal Offering of Common Shares

On June 22, 2018, TransAlta Renewables issued, pursuant to an underwritten offering on a bought deal basis, 11,860,000 common shares in the capital of TransAlta Renewables at a price of $12.65 per share for gross proceeds to TransAlta Renewables of approximately $150 million. As a result of the offering, our interest in TransAlta Renewables was reduced from approximately 64 per cent to 61 per cent.

Mr. Bryan Pinney Joins the Board of Directors

At our 2018 annual and special meeting of shareholders held on April 20, 2018, Mr. Bryan Pinney was elected as a new member of the Board of Directors, replacing Mr. Thomas Jenkins. Mr. Pinney has over 30 years of experience serving

many of Canada's largest corporations, primarily in energy and resources and construction. Mr. Pinney was a partner with Deloitte between 2002 and 2015. Mr. Pinney served as Calgary Managing Partner from 2002 through 2007, as National Managing Partner of Audit & Assurance from 2007 to 2011 and as Vice-Chair until June 2015.

Normal Course Issuer Bid

On March 9, 2018, the TSX accepted our notice to implement an NCIB. Pursuant to the NCIB, we may purchase up to a maximum of 14,000,000 of our common shares. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which our common shares are traded, based on the prevailing market price and subject to certain limitations. For the period March 14, 2018 to March 13, 2019, we purchased and cancelled a total of 3,264,500 common shares under this NCIB at an average price of $7.02 per common share for a total cost of approximately $23 million.

Redemption of Senior Notes

On March 15, 2018, we redeemed all of our then outstanding US$500 million 6.65 per cent senior notes maturing May 15, 2018. The redemption price for the notes was approximately $617 million, including a $5 million early redemption premium and accrued and unpaid interest on the notes to the redemption date.

2017

New Brunswick Wind Asset Project Financing

On October 2, 2017, TransAlta Renewables completed a $260 million bond offering on behalf of its indirect wholly-owned subsidiary, Kent Hills Wind LP, which is secured by a first ranking charge over all assets of Kent Hills Wind LP. The bonds are amortizing and bear interest from their date of issue at a rate of 4.454 per cent, payable quarterly and mature on November 30, 2033. Net proceeds were used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 expansion, which achieved commercial operation in October 2018, and to make advances to Canadian Hydro Developers, Inc. ("CHD") and to an affiliate of Natural Forces Technologies Inc., the Corporation's partner who owns approximately 17 per cent of Kent Hills Wind LP. The proceeds of the advances to CHD were used to redeem all of CHD's outstanding debentures.

The Honourable Rona Ambrose Joins the Board of Directors

Effective July 17, 2017, our Board of Directors appointed the Honourable Rona Ambrose to our Board of Directors. The Honourable Rona Ambrose is the former Leader of Canada's Official Opposition in the House of Commons and former leader of the Conservative Party of Canada. She also acted as Minister of the Crown across nine government departments, including serving as Vice-Chair of the Treasury Board and Chair of the cabinet committee for public safety, justice and aboriginal issues.

Balancing Pool Terminates the Sundance Alberta Power Purchase Arrangements

On September 18, 2017, we received formal notice from the Balancing Pool for the termination of the Alberta Power Purchase Arrangements for Sundance Unit B and Unit C effective March 31, 2018. We subsequently received $157 million in the first quarter of 2018 as a result of the PPA termination.

BUSINESS OF TRANSALTA

Our Canadian Coal, US Coal, Wind and Solar, Hydro, Canadian Gas and Australian Gas business segments are responsible for operating and maintaining our electrical generation facilities as well as the related mining operations in Canada and the US. The Energy Marketing segment is responsible for marketing our production and securing cost effective and reliable fuel supply. All the segments are supported by a Corporate segment.

As the Corporation transforms into a leading clean energy company, it is expected that the proportion of revenue attributable to the Canadian Coal and US Coal business will decline relative to the other business units. In addition, the Corporation continues to transition to a leaner organization through continuous optimization with a reduced cost structure to support the new business model.

The following table identifies each revenue generating business segment's contribution to revenues as at December 31, 2019:

	2019 Revenues[1]	2018 Revenues[1]
Canadian Coal	35%	41%
US Coal	24%	20%
Canadian Gas	9%	10%
Australian Gas	7%	7%
Wind and Solar	13%	12%
Hydro	7%	7%
Energy Marketing	5%	3%

Notes:

(1) Includes 100% of the revenue of TransAlta Renewables or its subsidiaries, as well as facilities in which TransAlta Renewables or one of its subsidiaries has an economic interest. We own, directly or indirectly, an aggregate interest of approximately 60 per cent of TransAlta Renewables.

For further information on our segment earnings and assets, please refer to Note 5 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. See "*Documents Incorporated by Reference*" in this AIF.

The following sections of this Annual Information Form provide detailed information on facilities by geographic location and fuel type.

Canadian Coal Business Segment

The following table summarizes our Canadian Coal generation facilities as at December 31, 2019:

Facility Name	Province	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Keephills Unit No. 1 [3]	AB	100	395	1983	Alberta PPA/Merchant	2020
Keephills Unit No. 2 [3]	AB	100	395	1984	Alberta PPA/Merchant	2020
Keephills Unit No. 3 [6]	AB	100	463	2011	Merchant	-
Sheerness Unit No. 1 [4]	AB	25	100	1986	Alberta PPA/Merchant	2020
Sheerness Unit No. 2	AB	25	98	1990	Alberta PPA	2020
Sundance Unit No. 3 [5][7]	AB	100	368	1976	Merchant	-
Sundance Unit No. 4 [5]	AB	100	406	1977	Merchant	-
Sundance Unit No. 5 [5][7]	AB	100	406	1978	Merchant	-
Sundance Unit No. 6 [5]	AB	100	401	1980	Merchant	-
Pioneer Pipeline	AB	50	N/A	2019	LTC	2034
Total Canadian Coal Net Capacity			**3,032**			

Notes:

(1) MW are rounded to the nearest whole number. Column may not add due to rounding.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) Merchant capacity includes a 12 MW uprate on units 1 and 2, which began operation in the second quarter of 2012.

(4) Merchant capacity includes a 10 MW uprate completed in the first quarter of 2016.

(5) The Balancing Pool elected to terminate the Sundance B PPA and Sundance C PPA effective on or before March 31, 2018.

(6) TransAlta and Capital Power completed an asset swap between Keephills Unit 3 and Genesee Unit 3 on October 1, 2019 pursuant to which TransAlta became the 100% owner of Keephills Unit 3 and no longer owns an interest in Genesee Unit 3.

(7) Unit mothballed up to November 1, 2021.

Keephills & Sundance

Keephills Unit 1 and 2 and the Sundance facilities are located approximately 70 kilometres west of Edmonton, Alberta, and are both owned by TransAlta. Keephills Unit 1 and Unit 2 each have a maximum capacity of 395 MW.

On September 18, 2017, we received formal notice from the Balancing Pool for the termination of Alberta Power Purchase Arrangements for Sundance Unit B (3 & 4) and Unit C (5 & 6) effective March 31, 2018. As a result, Sundance 4 and 6 have since been operating on a merchant basis within the Alberta market. Upon expiry of the Alberta PPAs,

Keephills 1 and 2 units will be merchant and dispatched to take advantage of price volatility in the Alberta energy-only electricity market and to provide ancillary services and, as such, will be part of our Alberta electricity portfolio optimization activities.

As part of our Clean Energy Investment Plan, we intend to convert coal-fired units into gas units through either a simple boiler conversion, or a more involved project to build a repowered combined cycle unit using existing and new assets. Our base plan involves three boiler conversions in the 2020 to 2021 period.

In 2019, we issued Full Notice to Proceed ("FNTP") to convert Sundance 6 and Keephills Unit 2 to natural gas by replacing the existing coal burners with natural gas burners. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020 and Keephills Unit 2 by the first half of 2021

We anticipate issuing Limited Notice to Proceed ("LNTP") for Keephills Unit 3 during the first half of 2020 and expect to complete the conversion of that unit during 2021. We are evaluating the potential to install dual-fuel capability at this unit to ensure we have optimal fuel flexibility as we transition the fleet from coal to gas, and to manage any timing delays in getting full gas requirements that may occur due to regulatory processes or other constraints.

We are currently seeking regulatory permits to repower the steam turbines at Sundance 5 and Keephills 1 by installing combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined cycle facility while achieving a similar heat rate.

We have acquired two 230 MW Siemens F-class gas turbines and related equipment that will be redeployed to our Sundance site to repower our Sundance Unit 5 to a highly efficient combined-cycle unit. We also acquired a long-term non-unit contingent PPA for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada). We expect to issue LNTP in 2020 and FNTP in 2021 for Sundance 5 with an expected commercial operation date in 2023. The repowered combined cycle unit will have a capacity of approximately of 730 MW. We are also concurrently permitting Keephills 1 to a combined-cycle unit depending on future market fundamentals.

Mothball of Sundance Units

On April 1, 2018, we mothballed Sundance Unit 3 and Sundance Unit 5. In early 2019, the AESO granted an extension to the continued mothballing of Sundance Units 3 and 5. The units will remain mothballed up to November 1, 2021 (extended from April 1, 2020). The extensions were requested by TransAlta based on our assessment of market prices and market conditions. TransAlta has the ability to return either of these unit back to full operation by providing three months' notice to the AESO.

The decision to mothball selected units ensures that the remaining units operate at high capacity utilization factors and competitive cost structures. See "*General Development of the Business - Three-Year History - Generation and Business Development*".

Sundance 1 and 2

On January 1, 2018, we retired Sundance Unit 1 and mothballed Sundance Unit 2. On July 31, 2018, we permanently retired Sundance Unit 2 due to its shorter useful life relative to other units, age, size and the capital requirements needed to return the unit to service. The retirement is consistent with our transition to clean power strategy.

Keephills 3 & Genesee 3

TransAlta and Capital Power formerly had joint venture arrangements through which each had a 50 per cent ownership interest of the Keephills 3 facility and Genesee 3 facility. The Genesee 3 facility, located approximately 50 kilometres west of Edmonton, was jointly owned with Capital Power. Capital Power was responsible for the operation of Genesee 3. TransAlta was responsible for operating the Keephills 3 facility. Keephills 3 began commercial operations on September 1, 2011. Each partner independently dispatched and marketed its share of the unit's electrical output. The Corporation provides the coal fuel to the Keephills 3 facility from its Highvale mine.

On October 1, 2019 TransAlta and Capital Power completed an agreement to swap interests in the Keephills 3 facility and the Genesee 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power now owns 100 per cent of the Genesee 3 facility. On closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated.

Highvale Mine

Fuel requirements for the Alberta thermal coal generation facilities that we operate are supplied by a surface strip coal mine located in close proximity to the facilities. We own the Highvale mine that supplies coal to the Sundance and Keephills facilities and perform the mining, reclamation and associated work at the Highvale mine. We estimate that the recoverable coal reserves contained in this mine are sufficient to supply the anticipated requirements for the life of the facilities it serves.

We also own the Whitewood mine, which formerly supplied coal to the now decommissioned Wabamun facility. The Whitewood mine is no longer in operation and we have completed reclamation of the site.

Sheerness 1 & 2

The Sheerness facilities are located approximately 200 kilometres northeast of Calgary, Alberta and is jointly owned by TransAlta Cogeneration LP ("TA Cogen") and Heartland Generation Ltd. ("Heartland"). Heartland is responsible for the operation and maintenance of these units. Coal for the Sheerness facilities is provided from the adjacent Sheerness mine. The coal reserves of the mine are owned, leased or controlled jointly by TA Cogen, Heartland and Westmoreland Coal. TA Cogen and Heartland have entered into coal supply agreements with Westmoreland Coal, which operates the mine. See "*Business of TransAlta – Non-Controlling Interests*".

Sheerness Unit 2 will be converted to gas by Heartland during the first quarter of 2020.

Off-Coal Agreement

On November 24, 2016, we entered into the Off-Coal Agreement with the Government of Alberta pertaining to our cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired facilities. The Off-Coal Agreement provides that we are entitled to receive annual cash payments of approximately $37.4 million, net to TransAlta, from the Government of Alberta commencing in 2017 and terminating in 2030, subject to satisfaction of certain terms and conditions including our cessation of all coal-fired emissions on or before December 31, 2030. Other conditions include maintaining prescribed spending on investment and investment-related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), maintaining spending on programs and initiatives to support the communities surrounding the plants and the employees of the Corporation negatively impacted by the phase-out of coal generation, and the fulfillment of all obligations to affected employees, in each case as prescribed by the Off-Coal Agreement. See "*General Development of the Business - Three-Year History - Generation and Business Development*".

Pioneer Pipeline

As part of our conversion strategy to convert our Canadian Coal business to gas-powered generation, we exercised our option to acquire 50 per cent ownership in the Pioneer gas pipeline which transports gas to the Keephills and Sundance facilities. We and Tidewater each own a 50 per cent interest in the Pioneer gas pipeline which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls.

During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule. The 130 km pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on November 1, 2019. The pipeline has the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline not only supplies gas to the units once fully converted, it also allows us to currently co-fire using a blend of natural gas and coal.

Canadian Gas Business Segment

The following table summarizes our Canadian natural gas-fired generation facilities as at December 31, 2019:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Fort Saskatchewan[5]	AB	30	35	1999	Dow Chemical/Merchant	2029
Poplar Creek[4]	AB	100	230	2001	Suncor	2030
Ottawa[5]	ON	50	37	1992	LTC/Merchant	2020-2033
Sarnia[3]	ON	100	499	2003	LTCs	2022-2025
Windsor[5]	ON	50	36	1996	IESO/Merchant	2031
Total Canadian Gas Net Capacity[6]			**837**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As at December 31, 2019, TransAlta owns, directly or indirectly, approximately 60 per cent of the common shares in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) Facility is owned by TransAlta Renewables.

(4) The Poplar Creek plant is operated by Suncor Energy Inc. and ownership of the facility will transfer to Suncor in 2030.

(5) Our interests in these facilities are through our ownership interest in TA Cogen.

(6) *Excludes the Kaybob facility which is an asset under construction.*

Fort Saskatchewan

We have a net ownership interest of 30 per cent in the Fort Saskatchewan facility. See "*Business of TransAlta – Non-Controlling Interests*". The 118 MW natural gas-fired combined-cycle cogeneration Fort Saskatchewan plant is owned by TA Cogen and Prairie Boys Capital Corporation (previously known as Strongwater Energy Ltd). During the fourth quarter of 2017, we entered into a long-term contract for the Fort Saskatchewan facility providing for the delivery of energy and steam to the customer. The contract has an initial 10-year term, which commenced on January 1, 2020, with the option for two five-year extensions. The contract allows our customer to continue to benefit from the operational flexibility of the plant.

Poplar Creek

Our Poplar Creek plant is located in Fort McMurray, Alberta. On August 31, 2015, the Corporation restructured its contractual arrangement for the power generation services of its Poplar Creek plant. The Poplar Creek cogeneration facility had been built and contracted to provide steam and electricity to Suncor's oil sands operations. Under the terms of the new arrangement, Suncor acquired from the Corporation two steam turbines with an installed capacity of 126 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the cogeneration facility and has the right to use the full 230 MW capacity of the Corporation's gas generators until December 31, 2030. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030.

Mississauga

The Mississauga cogeneration facility is owned by TA Cogen. See "*Business of TransAlta – Non-Controlling Interests*". It is a combined-cycle cogeneration facility designed to produce 108 MW of electrical energy. The capacity was contracted under a long-term contract with the Independent Electricity System Operator ("IESO"). In December 2016, we agreed to terminate our existing arrangement with the IESO and entered into a new Non-Utility Generator ("NUG") Enhanced Dispatch Contract effective January 1, 2017. Under the new NUG Contract, we received fixed monthly payments until December 31, 2018 with no delivery obligations. With the expiry of this NUG Contract, in December 2018 TransAlta exercised its option to terminate its land lease agreement with Boeing Canada Inc. effective December 31, 2021. TransAlta is now required to remove the plant and restore the site within the three-year time frame. Decommissioning work is scheduled to begin in early 2020 and will be completed by the end of year, including all remediation and restoration work required to return the property to its original condition.

Ottawa

The Ottawa plant is owned by TA Cogen. See "*Business of TransAlta – Non-Controlling Interests*". It is a combined-cycle cogeneration facility designed to produce 74 MW of electrical energy. On August 30, 2013, the Corporation announced the recontracting of the plant with the IESO for a 20-year term, effective January 2014. The Ottawa plant also provides steam, hot water, and chilled water to the member hospitals and treatment centres of the Ottawa Health Sciences

Centre and the National Defence Medical Centre. The thermal energy contract with the Ottawa Health Sciences Centre expires January 1, 2024.

Sarnia

The Sarnia Plant is a 499 MW combined-cycle cogeneration facility located in Sarnia, Ontario. The plant provides power and steam to nearby industrial facilities owned by ARLANXEO Canada Inc. (formerly LANXESS AG, successor to Bayer Inc.), Nova Chemicals Corporation (Canada) Ltd. ("NOVA") (which in turn supplies INEOS Styrolution, a styrene production facility formerly owned by NOVA) and Suncor Energy Products Partnership under contracts terminating in 2022. We are currently evaluating potential extensions to these power and steam off-take agreements. The facility also provides electricity to the IESO under a contract that terminates December 31, 2025. In the first quarter of 2020, the Corporation executed a 30 MW PPA for a five-year initial term with a leading financial technology company that will be located at the Corporation's Bluewater Energy Park at Sarnia.

The Sarnia Plant utilizes three Alstom 11N2 gas turbines, each capable of generating between 102 MW and 118 MW, one condensing steam turbine that can produce 120 MW, and back-pressure steam turbines capable of generating 56 MW. The plant also incorporates a fired boiler, river water pump houses, and water treatment plants. In 2018, Sarnia's capacity was reduced from 506 MW to 499 MW due to the lay-up of one generator. The reduction in capacity does not impact the plant's ability to meet its contractual requirements.

Windsor

The Windsor plant is owned by TA Cogen. See "*Business of TransAlta – Non-Controlling Interests*". It is a combined-cycle cogeneration facility designed to produce 72 MW of electrical energy, of which, 50 MW was sold under a long-term contract to the Ontario Electricity Financial Corporation ("OEFC"). This agreement with the OEFC expired November 30, 2016. Effective December 1, 2016, the Windsor plant began operating under an agreement with the IESO with a 15-year term for up to 72 MW of capacity. The Windsor plant also provides thermal energy to Fiat Chrysler Automobiles Canada Inc.'s minivan assembly facility in Windsor under a contract that expires in November 2020.

Kaybob Cogeneration

TransAlta and SemCAMs entered into definitive agreements to develop, construct and operate a new cogeneration facility at the Kabob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts gas production out of the Montney and Duvernay formations. The cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMs under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven year extension subject to certain termination rights.

Australian Gas Business Segment

The following table summarizes our Australian assets:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date
Parkeston[2][3]	WA[4]	50	55	1996	Newmont Power Pty Ltd.	2026
South Hedland[2]	WA[4]	100	150	2017[5]	LTCs[6]	2042
Southern Cross Energy[2][7]	WA[4]	100	245	1996	BHP Billiton Nickel West Pty Ltd	2023
Fortescue River Gas Pipeline	WA[4]	43	N/A	2015	Fortescue Metals Group	2035
Total Australian Gas Net Capacity			**450**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As at December 31, 2019, TransAlta owned approximately 60 per cent of the common shares in TransAlta Renewables.

(2) TransAlta Renewables owns an economic interest in the facility.

(3) Plant contracted to October 2026 with early termination options beginning in 2021.

(4) Western Australia.

(5) Fortescue Metals Grouip ("FMG") is contracted for 23% of the capacity, with Horizon Power contracting for the remaining 77% of capacity. FMG is disputing the Corporation's declaration of commercial operation date. See "Legal Proceedings and Regulatory Actions".

(6) Long-term contracts with two counterparties: Horizon Power and FMG. On November 13, 2017, FMG purported to terminate the PPA for South Hedland

(7) Comprised of four facilities.

All of our Australian assets are owned, directly or indirectly, by TransAlta Energy (Australia) Pty Ltd. ("TEA"), a wholly owned subsidiary of TransAlta. On May 7, 2015, TransAlta Renewables acquired tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows broadly equal to the underlying net distributable cash flow of TEA, in consideration for a payment equal to $1.78 billion, which amount included funding the remaining construction costs for South Hedland.

Pursuant to the terms of the tracking preferred shares, TransAlta Renewables is entitled to receive, in priority to the common shares in the capital of TEA, quarterly preferential cash dividends. The preferred shares have no residual right to participate in the earnings of TEA. In the event of the liquidation, dissolution or winding-up of TEA or any other distribution of the assets of TEA among its shareholders for the purpose of winding up its affairs, TransAlta Renewables is entitled, subject to applicable law, to receive from TEA as the sole holder of preferred shares, before any distribution of TEA to the holders of the common shares or any other shares ranking junior to the preferred shares, an amount equal to the fair market value of the Australian assets.

Parkeston

The Parkeston plant is a 110 MW dual-fuel natural gas and diesel-fired power station, which we own in partnership through a 50/50 joint venture with NP Kalgoorlie Pty Ltd., a subsidiary of Newmont Australia Limited. The Parkeston facility primarily supplies energy to Kalgoorlie Consolidated Gold Mines and the initial supply contract ended in 2016. The plant was re-contracted effective November 1, 2016, and the agreement extends the previous contract to October 2026, with options for early termination available to either party beginning in 2021. We are evaluating potential opportunities to renew or extend the supply contract. Any merchant capacity and energy are sold into Western Australia's wholesale electricity market. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Parkeston facility on May 7, 2015.

Southern Cross

Southern Cross Energy is composed of four natural gas and diesel-fired generation facilities with a combined capacity of 245 MW. Southern Cross Energy sells its output pursuant to a contract with BHP Billiton Nickel West, which was renewed in October 2013 for 10 years. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Southern Cross Energy facilities on May 7, 2015.

South Hedland

In 2014, TransAlta was selected as the successful bidder to design, build, own and operate a 150 MW combined cycle power station near South Hedland, Western Australia. Construction began in early 2015 and the plant achieved commercial operation on July 28, 2017. The plant was fully contracted with two customers for a 25-year term. The majority of the plant's capacity remains contracted to Horizon Power, the state-owned electricity supplier in the region. The second customer is the port operations of FMG for 35 MW of capacity. In November 2017, we received a notice from FMG purporting to terminate their PPA. We have disputed this notice and are currently in litigation with FMG in respect of this dispute. The case is scheduled to be before the courts in mid-2020. See "*Legal Proceedings and Regulatory Actions*" for further details. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the South Hedland facility on May 7, 2015.

Fortescue River Gas Pipeline

In 2014, we established the Fortescue River Gas Pipeline joint venture with DBP Development Group. The joint venture (of which TransAlta is a 43 per cent partner) was successfully awarded the contract to design, build, own and operate the 270 km Fortescue River Gas Pipeline to deliver natural gas to the Solomon facility. The pipeline was completed in the first quarter of 2015 and operates under a take-or-pay gas transport agreement with a subsidiary of FMG for an initial term of 20 years. Under the gas tariff agreement, FMG has the option to purchase the Fortescue River Gas Pipeline commencing March 2020. The 16-inch diameter pipeline has an initial free-flow capacity of 64 TJ per day. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the pipeline on May 7, 2015.

Wind and Solar Business Segment

As at December 31, 2019, the Wind and Solar segment held interests in approximately 1,446 MW of net wind generating capacity from 10 wind farms in Western Canada, four in Ontario, two in Québec, three in New Brunswick and four in the United States, more specifically in the states of Wyoming, Minnesota, Pennsylvania and New Hampshire. We also hold an interest in a 21 MW solar facility in the state of Massachusetts in the United States.

Wind and solar are not generally a dispatchable fuel. Therefore, in merchant markets, wind and solar assets may not be able to secure the annual average pool price. As such, we make different assumptions in forecast revenue received for generation from a wind or solar asset compared to a base load asset. If these price assumptions and generation production forecasts are not correct, the corresponding revenue received may be reduced. Generation production forecasts are based on the long-term average production forecast for a site, reflecting historical climatic conditions.

Within any year there may be variations from this long-term average. In order to forecast generation production, a number of factors have to be assumed based on historic on-site data. For a wind farm, this includes wind farm design including wake and array losses, wind shear and the electrical losses within the site. For a solar plant, long-term energy production depends on panel angle and row spacing, amount of sun, ambient conditions such as temperature and wind speed and losses at the site. If these assumptions are incorrect then actual production will be higher or lower than the long-term forecast for the site.

As well as contracting for the sale of the power generated, we also enter into long-term and short-term contracts to sell the environmental attributes from the merchant wind facilities, including offsets and RECs. These activities help to ensure earnings consistency from these assets. Generally, for facilities under long-term contract, the purchaser under such long-term contracts also has the benefit of any environmental attributes.

The following table summarizes our Wind and Solar generation facilities:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Alberta Wind Facilities						
Ardenville [4] [5]	AB	100	69	2010	Merchant	-
Blue Trail [4] [5]	AB	100	66	2009	Merchant	-
Castle River [4] [5] [6]	AB	100	44	1997-2001	Merchant	-
Cowley North [4] [5]	AB	100	20	2001	Merchant	-
Macleod Flats [4] [5]	AB	100	3	2004	Merchant	-
McBride Lake [4] [5]	AB	50	38	2004	ENMAX	2024
Sinnott [4] [5]	AB	100	7	2001	Merchant	-
Soderglen [4] [5]	AB	50	35	2006	Merchant	-
Summerview 1 [4] [5]	AB	100	70	2004	Merchant	-
Summerview 2 [4] [5]	AB	100	66	2010	Merchant	-
Eastern Canada Wind Facilities						
Kent Breeze [4]	ON	100	20	2011	IESO	2031
Kent Hills 1 [4]	NB	83	80	2008	NB Power	2035
Kent Hills 2 [4]	NB	83	45	2010	NB Power	2035
Kent Hills 3 [4]	NB	83	14	2018	NB Power	2035
Le Nordais [4] [5] [7]	QC	100	98	1999	Hydro-Québec	2033
Melancthon I [4]	ON	100	68	2006	IESO	2026
Melancthon II [4]	ON	100	132	2008	IESO	2028
New Richmond [4] [5]	QC	100	68	2013	Hydro-Québec	2033
Wolfe Island [4]	ON	100	198	2009	IESO	2029
US Wind and Solar Facilities						
Antrim [3]	NH	100	29	2019	Partners HealthCare and New Hampshire Electric	2038
Big Level [3]	PA	100	90	2019	Microsoft	2033
Lakeswind [3]	MN	100	50	2014	LTC	2034
Mass Solar [3][8]	MA	100	21	2012-2015	LTC	2032-2045
Wyoming Wind [3]	WY	100	140	2003	LTC	2028
Total Wind and Solar Net Capacity[9]			**1,467**			

Notes:

(1) MW are rounded to the nearest whole number. Column may not add due to rounding. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As at December 31, 2019, TransAlta owned, directly and indirectly, approximately 60 per cent of the common shares in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) TransAlta Renewables owns an economic interest in the facility.

(4) Facility owned directly by TransAlta Renewables.

(5) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards.

(6) Includes seven additional turbines at other locations.

(7) Comprised of two facilities.

(8) Comprised of multiple facilities.

(9) Excludes Windcharger and Windrise which are assets under construction.

All of the electricity generated and sold by our Wind segment within Alberta and Quebec, are from facilities that are EcoLogo certified. We are an EcoLogo-certified distributor of Alternative Source Electricity through Environment Canada's Environmental Choice Program.

Alberta Wind Facilities

Ardenville

The Ardenville facility is owned by TransAlta Renewables. Ardenville is a 69 MW wind farm located approximately eight kilometres south of Fort Macleod, Alberta adjacent to the Macleod Flats wind facility. We constructed the project, which commenced commercial operations on November 10, 2010. In 2018, the Ardenville wind farm was granted an extension to create offset credits under the Alberta Technology Innovation and Emissions Reduction ("TIER") Regulation until October 2023 and is entitled to receive EcoENERGY for Renewable Power payments until November 2020. We acquire the generation from the facility pursuant to a Renewables PPA (as defined in the Glossary of Terms), and subsequently sell such generation in the Alberta spot market.

Blue Trail

The Blue Trail facility is owned by TransAlta Renewables. Blue Trail is a 66 MW wind farm located in southern Alberta, which commenced commercial operations in November 2009. The Blue Trail wind farm creates carbon offset credits under TIER until September 2022 and was entitled to receive EcoENERGY payments until November 2019. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Castle River

The Castle River facility is owned by TransAlta Renewables. Castle River is a 44 MW wind facility which is comprised of 66 Vestas wind turbines (three Vestas V44 600 kW wind turbines and 63 Vestas V47 660 kW wind turbines) on 50 metre towers, and is located southwest of Pincher Creek, Alberta. This facility also includes an additional six turbines, totaling 4 MW, that are located individually in the Cardston County and Hillspring areas of south western Alberta. This facility began commercial operations in stages from November 1997 through to July 2001. This facility generates Emissions Performance Credits ("EPCs") under the TIER system. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Cowley North

The Cowley North facility is owned by TransAlta Renewables. Cowley North is a 20 MW wind farm that is comprised of 15 1.3 MW Nordex N60 wind turbines on 65-metre towers, and is located near the towns of Cowley and Pincher Creek, in southern Alberta. This facility began commercial operations in the fall of 2001. The Cowley North wind farm creates EPCs under TIER. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Macleod Flats

The Macleod Flats facility is owned by TransAlta Renewables. Macleod Flats consists of a single 3 MW turbine and is located near Fort Macleod. It was commissioned in 2004 and was purchased by us in 2009. This facility generates renewable credits. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

McBride Lake

The McBride Lake facility is owned by TransAlta Renewables. The 75 MW McBride Lake wind facility, which is partially owned by ENMAX Generation Portfolio Inc., is comprised of 114 Vestas V47 (660 kW) wind turbines on 50-metre towers, and is located south of Fort Macleod, Alberta. This facility began commercial operations in April 2004. Generation from this facility is sold under a 20-year PPA with ENMAX Energy Corp. that terminates in 2024. This facility will generate EPCs under the TIER system.

Sinnott

The Sinnott facility is owned by TransAlta Renewables. Sinnott has a total installed capacity of 7 MW that is comprised of five, 1.3 MW Nordex N60 wind turbines on 65-metre towers, and is located directly east of the Cowley North wind facility and north of Pincher Creek, Alberta. This facility began commercial operations in the fall of 2001. The Sinnott wind farm creates EPCs under the TIER system. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Soderglen

The Soderglen facility is owned by TransAlta Renewables. Soderglen is a 71 MW facility that is comprised of 47 1.5 MW GE SLE wind turbines on 65-metre towers, and is located southwest of Fort Macleod. This facility began commercial operations in September 2006. The Soderglen wind farm creates EPCs under the TIER system. TransAlta Renewables owns the facility equally with Nexen Energy ULC. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell 50 per cent of such generation in the Alberta spot market (which excludes that portion of generation that is owned by Nexen Energy ULC).

Summerview 1

The Summerview 1 facility is owned by TransAlta Renewables. Summerview 1 is a 66 MW wind farm located approximately 15 kilometres northeast of Pincher Creek, Alberta. We constructed Summerview and it commenced commercial operations in 2004. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Summerview 2

The Summerview 2 facility is owned by TransAlta Renewables. Summerview 2 is a 66 MW wind farm that is comprised of 38, 1.8 MW Vestas V80 wind turbines on 67 metre towers, and is located approximately 15 kilometres northeast of Pincher Creek, Alberta. This facility began commercial operations in September 2004. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Windcharger

Windcharger is an energy storage project that will have a nameplate capacity of 10 MW and a total storage capacity of 20 MWh. Windcharger is located in southern Alberta in the Municipal District of Pincher Creek next to the existing Summerview wind farm substation. Windcharger will store energy produced by the nearby Summerview 2 wind farm and discharge into the Alberta electricity grid at times of high-peak demand. The project is expected to the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the AUC and an interconnection application to the AESO, have been submitted. AUC approval was granted in November 2019 and the AESO approval is expected by the end of the first quarter of 2020. Construction is on-track to begin in March 2020 with a commercial operation date expected within the second quarter of 2020. The Windcharger project has been identified as a potential candidate for transfer of ownership to TransAlta Renewables.

Windrise

On December 17, 2018, TransAlta's project Windrise was selected by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. Windrise is 207 MW wind project situated on 11,000 acres of land located in the county of Willow Creek. TransAlta and the AESO have executed a Renewable Electricity Support Agreement with a 20-year term. Windrise has secured approval for the facility from the AUC and is currently permitting transmission lines required to connect the facility to the Alberta grid. Construction activities will start in the second quarter of 2020 and the project is on track to reach commercial operation during the first half of 2021. The Windrise project has been identified as a potential candidate for transfer of ownership to TransAlta Renewables.

Eastern Canada Wind Facilities

Kent Breeze

Kent Breeze is a 20 MW wind project located in Thamesville, Ontario. This facility began commercial operations in 2011. Generation from this facility is sold to the IESO. Kent Breeze is entitled to receive ecoENERGY payments until December 31, 2021. On May 31, 2018 this facility was acquired by TransAlta Renewables. See "*General Development of the Business – Three-Year History - Generation and Business Development*".

Kent Hills 1

The Kent Hills 1 facility is owned by TransAlta Renewables. Kent Hills is a 96 MW project located in Kent Hills, New Brunswick, and delivers power under a 25-year PPA with New Brunswick Power. Natural Forces Technologies Inc. ("Natural Forces"), an Atlantic Canada-based wind developer, is our co-development partner in this project and exercised its option to purchase 17 per cent of the Kent Hills project in May 2009. Kent Hills began commercial operations in 2008. On June 1, 2017, the term of the Kent Hills 1 PPA was extended by two years to 2035. The Kent Hills 1 facility received ecoENERGY payments up until December 31, 2018.

Kent Hills 2

The Kent Hills 2 facility is owned by TransAlta Renewables. This Kent Hills expansion is a 54 MW wind farm that also delivers power under a 25-year PPA with New Brunswick Power, expiring in 2035. Natural Forces exercised its option to purchase a 17 per cent interest in the Kent Hills 2 expansion project subsequent to the commencement of commercial operations. The facility began commercial operations in 2010. The Kent Hills 2 facility is owned by TransAlta Renewables and is entitled to receive ecoENERGY payments until November 2020.

Kent Hills 3

The Kent Hills 3 facility is owned by TransAlta Renewables. On June 1, 2017, we signed a PPA with New Brunswick Power for the further expansion of the Kent Hills wind farm. This expansion project, Kent Hills 3, reached commercial operations as of October 19, 2018 and adds five 3.45 MW turbines to the Kent Hills fleet for an additional 17.25 MW at the site, bringing total generating capacity of the three Kent Hills facilities to 167 MW. The Kent Hills 3 PPA expires in 2035. See "*General Development of the Business – Three-Year History - Generation and Business Development*".

Le Nordais

The 98 MW Le Nordais wind facility is located at two sites: Cap-Chat with 55.5 MW of installed capacity comprised of 74 750 kW NEG-Micon wind turbines on 55-metre towers; and Matane with 42 MW of installed capacity comprised of 56 750 kW NEG-Micon wind turbines on 55-metre towers. Le Nordais is located on the Gaspé Peninsula of Québec. It began commercial operations in 1999. Generation from this facility is sold to Hydro-Québec and generates RECs. On January 6, 2016, TransAlta Renewables acquired from the Corporation tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows, in part, from the Le Nordais facilities. Subsequently, on November 30, 2016, the economic interest was replaced with direct ownership of the entity that owns the Le Nordais wind farm. See "*Business of TransAlta – Non-Controlling Interests*".

Melancthon I

The Melanchton I facility is owned by TransAlta Renewables. Melancthon I is a 68 MW wind project that is comprised of 45, 1.5 MW GE wind turbines on 80 metre towers, and is located in Melancthon Township near Shelburne, Ontario. This facility began commercial operations in March 2006. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2026.

Melancthon II

The Melancthon II facility is owned by TransAlta Renewables. Melancthon II is a 132 MW wind project that is comprised of 88 1.5 MW GE wind turbines on 80 metre towers, and is located adjacent to Melancthon I, in Melancthon and Amaranth Townships, Ontario. This facility began commercial operations in November 2008. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2028.

New Richmond

The New Richmond facility is owned by TransAlta Renewables. New Richmond is a 68 MW wind project that is comprised of 27 2.0 MW and six, 2.3 MW Enercon E82 wind turbines on 100 metre towers, and is located in New Richmond, Québec. This facility began commercial operations in March 2013. Generation from this facility is sold under a 20-year electricity supply agreement with Hydro-Québec Distribution that terminates in 2033.

Wolfe Island

The Wolfe Island facility is owned by TransAlta Renewables. Wolfe Island is a 198 MW wind project that is comprised of 86 2.3 MW Siemens SWT 93 wind turbines on 80 metre towers, and is located on Wolfe Island, near Kingston, Ontario. This facility began commercial operations in June 2009. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2029. Wolfe Island was entitled to receive EcoENERGY payments until June 2019.

US Wind and Solar Facilities

Antrim

The Antrim Wind Farm is a 29 MW wind project located in Antrim, New Hampshire. The wind farm was constructed by TransAlta Corporation and was commissioned in December 2019. The wind farm is fully operational and contracted under two long-term PPAs until 2039 with Partners Healthcare and New Hampshire Electric. On February 28, 2018 TransAlta Renewables acquired tracking preferred shares from the Corporation that provides TransAlta Renewables with an economic interest in the wind farm. See "*General Developments of the Business – Three-Year History - Generation and Business Development*".

Big Level

The Big Level Wind Farm is a 90 MW wind project located in Potter County, Pennsylvania. The wind farm was constructed by TransAlta Corporation and was commissioned in December 2019. The wind farm is fully operational and contracted under a long-term PPA until 2034 with Microsoft. On February 28, 2018, TransAlta Renewables acquired tracking preferred shares from the Corporation that provides TransAlta Renewables with an economic interest in the wind farm. See "*General Developments of the Business – Generation and Business Development*".

Lakeswind

The Lakeswind Wind Farm is a 50 MW wind project located near Rollag, Minnesota. The wind farm was acquired in 2015 from an affiliate of Rockland Capital LLC. The wind farm is fully operational and contracted under a long-term PPA until 2034 with several high-quality counterparties. On May 31, 2018, TransAlta Renewables acquired tracking preferred shares from the Corporation that provides TransAlta Renewables with an economic interest in the wind farm. See "*General Developments of the Business – Generation and Business Development*".

Mass Solar

The Mass Solar Farm is a 21 MW solar project consisting of multiple facilities located in Massachusetts. The wind farm was acquired in 2015 from an affiliate of Rockland Capital LLC. The operational solar farm is contracted under a long-term PPA with several high-quality counterparties. In addition to revenue generated under the PPA, the projects generate Solar RECs that expire in 2024. On May 31, 2018 TransAlta Renewables acquired tracking preferred shares from the Corporation that provide TransAlta Renewables with an economic interest in the solar farm. See "*General Development of the Business – Three-Year History - Generation and Business Development*" and "*Business of TransAlta – Non-Controlling Interests – TransAlta Renewables*".

Wyoming

The Wyoming Wind Farm is a 140 MW wind project located near Evanston, Wyoming. The wind farm was acquired in December 2013 from an affiliate of NextEra Energy Resources, LLC. The wind farm is contracted under a long-term PPA until 2028 with an investment grade counterparty. TransAlta Renewables holds tracking preferred shares from the Corporation that provides TransAlta Renewables with an economic interest in the wind farm. See "*Non-Controlling Interests – TransAlta Renewables*".

Hydro Business Segment

The Hydro business segment holds an interest in 926 net MWs. The facilities are located in British Columbia, Alberta, Ontario and Washington State.

As well as contracting for power, long-term and short-term contracts are entered into to sell the environmental attributes from the merchant hydro facilities. These activities help to ensure earnings stability from these assets. Generally, for facilities under long-term contract, the benefit of the environmental attributes generated flow through to the contract holder.

The following table summarizes our hydroelectric facilities as at December 31, 2019:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Alberta - Bow River System						
Barrier[3]	AB	100	13	1947	Alberta PPA	2020
Bearspaw[3]	AB	100	17	1954	Alberta PPA	2020
Cascade[3]	AB	100	36	1942, 1957	Alberta PPA	2020
Ghost[3]	AB	100	54	1929, 1954	Alberta PPA	2020
Horseshoe[3]	AB	100	14	1911	Alberta PPA	2020
Interlakes[3]	AB	100	5	1955	Alberta PPA	2020
Kananaskis[3]	AB	100	19	1913, 1951	Alberta PPA	2020
Pocaterra	AB	100	15	1955	Merchant	-
Rundle[3]	AB	100	50	1951, 1960	Alberta PPA	2020
Spray[3]	AB	100	112	1951, 1960	Alberta PPA	2020
Three Sisters[3]	AB	100	3	1951	Alberta PPA	2020
Alberta - Oldman River System						
Belly River [4] [5]	AB	100	3	1991	Merchant	-
St. Mary [4] [5]	AB	100	2	1992	Merchant	-
Taylor [4] [5]	AB	100	13	2000	Merchant	-
Waterton [4] [5]	AB	100	3	1992	Merchant	-
Alberta - North Saskatchewan River System						
Bighorn[3]	AB	100	120	1972	Alberta PPA	2020
Brazeau[3]	AB	100	355	1965, 1967	Alberta PPA	2020
BC Hydro Facilities						
Akolkolex [4] [5]	BC	100	10	1995	BC Hydro	2046
Pingston [4] [5]	BC	50	23	2003, 2004	BC Hydro	2023
Bone Creek [4] [5]	BC	100	19	2011	BC Hydro	2031
Upper Mamquam [4] [5]	BC	100	25	2005	BC Hydro	2025
Ontario Hydro Facilities						
Appleton [4]	ON	100	1	1994	IESO	2030
Galetta [4] [7]	ON	100	2	1998	IESO	2030
Misema [4]	ON	100	3	2003	IESO	2027
Moose Rapids [4]	ON	100	1	1997	IESO	2030
Ragged Chute [4]	ON	100	7	1991	IESO	2029
US Hydro Facilities						
Skookumchuck [6]	WA	100	1	1970	PSE	2020
Total Hydroelectric Net Capacity			**926**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As at December 31, 2019, TransAlta owned, directly or indirectly, approximately 60 per cent of the common shares in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) *These* facilities form part of the "Hydro Assets" subject to the Brookfield investment. See "*General Development of the Business - Three-Year History - Strategic Investment by Brookfield Renewable Partners*."

(4) Facility owned by TransAlta Renewables.

(5) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards.

(6) This facility is used to provide a reliable water supply to Centralia Coal.

(7) Galetta was originally built in 1907, but was retrofitted in 1998.

Bow River System

Barrier

Barrier is a run-of-river hydroelectric facility with installed capacity of 13 MW located on the Kananaskis River in Seebe, Alberta. It has been operating since 1947. The facility operates under an Alberta PPA.

Bearspaw

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. It has been operating since 1954. The facility operates under an Alberta PPA.

Cascade

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. We purchased this facility from the Government of Canada in 1941. The following year, we built a new dam and power plant to replace the original, and then, in 1957, added a second generating unit. The facility operates under an Alberta PPA.

Ghost

Ghost is a hydroelectric facility with installed capacity of 54 MW located on the Bow River in Cochrane, Alberta. It has been operating since 1929. The facility operates under an Alberta PPA.

Horseshoe

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located on the Bow River in Seebe, Alberta. It has been operating since 1911. The facility operates under an Alberta PPA.

Interlakes

Interlakes is a hydroelectric facility with installed capacity of 5 MW located at Kananaskis Lakes, Alberta. It has been operating since 1955. The facility operates under an Alberta PPA.

Kananaskis

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located on the Bow River in Seebe, Alberta. It has been operating since 1913. It was expanded in 1951 and modified in 1994. The facility operates under an Alberta PPA.

Pocaterra

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located at Kananaskis Lakes, Alberta. It has been operating since 1955. Generation from the facility is sold in the Alberta spot market.

Rundle

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta, on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. It has been operating since 1951. The facility operates under an Alberta PPA.

Spray

Spray is a hydroelectric facility with installed capacity of 112 MW located in Canmore, Alberta, on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. It has been operating since 1951. The facility operates under an Alberta PPA.

Three Sisters

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam in Canmore, Alberta, on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. It has been operating since 1951. The facility operates under an Alberta PPA.

Oldman River System

Belly River

The Belly River facility is owned by TransAlta Renewables. Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in Southern Alberta. Due to its location along the

irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. It has been operating since 1991. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

St. Mary

The St. Mary facility is owned by TransAlta Renewables. St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the St. Mary Dam on the Waterton Reservoir, near Magrath, in Southern Alberta. It has been operating since 1992. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Taylor

The Taylor facility is owned by TransAlta Renewables. Taylor is a run-of-river hydroelectric facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System, which is owned by the Government of Alberta. It has been operating since 2000. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Waterton

The Waterton facility is owned by TransAlta Renewables. Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hillspring, southwest of Lethbridge, Alberta. It has been operating since 1992. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

North Saskatchewan River System

Bighorn

Bighorn is a hydroelectric facility with installed capacity of 120 MW located in Nordegg, Alberta. It has been operating since 1972. The facility operates under an Alberta PPA.

Brazeau

Brazeau is a hydroelectric facility with installed capacity of 355 MW located in Drayton Valley, Alberta. It has been operating since 1965. The facility operates under an Alberta PPA.

BC Hydro Facilities

Akolkolex

The Akolkolex facility is owned by TransAlta Renewables. Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW located on the Akolkolex River, south of Revelstoke, British Columbia. It has been operating since 1995. In 2016, TransAlta entered into a new 30-year agreement to sell the output from the facility to the British Columbia Hydro Power Authority ("BC Hydro").

Pingston

Pingston is a run-of-river hydroelectric facility with installed capacity of 45 MW located on Pingston Creek, southwest of Revelstoke, British Columbia, and down river of the Akolkolex facility. It has been operating since 2003. TransAlta Renewables owns the facility equally with Brookfield Renewable Power Inc. The output from the facility is sold to BC Hydro.

Bone Creek

The Bone Creek facility is owned by TransAlta Renewables. Bone Creek is a run-of-river hydroelectric facility with installed capacity of 19 MW located on Bone Creek, 90 kilometres south of the town of Valemount, British Columbia. It has been operating since 2011. The output from the facility is under contract with BC Hydro. The facility also currently qualifies for payments of $10/MWh until December 2020 from Natural Resources Canada, a division of the federal government, through the ecoENERGY Renewable Power program.

Upper Mamquam

The Upper Mamquam facility is owned by TransAlta Renewables. Upper Mamquam is a run-of-river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver. It has been operating since 2005. The wholly owned facility utilizes two horizontal axis double Litostroj

Francis turbines and Leroy Somer generators. The output from the facility is sold to BC Hydro under a PPA that terminates in 2025.

Ontario Hydro Facilities

Appleton

The Appleton facility is owned by TransAlta Renewables. Appleton is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Mississippi River, near Almonte, Ontario. The facility has been operating since 1994. Generation from this facility is sold to Ontario's IESO under a contract that terminates on December 31, 2030.

Galetta

The Galetta facility is owned by TransAlta Renewables. Galetta is a run-of-river hydroelectric facility with installed capacity of 2 MW located on the Mississippi River, near Galetta, Ontario. This facility was originally built in 1907 and retrofitted in 1998. Generation from this facility is sold to the IESO under a contract that terminates on December 31, 2030.

Misema

The Misema facility is owned by TransAlta Renewables. Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. This facility has been operating since 2003. Generation from this facility is sold to the IESO under a contract that terminates on May 3, 2027.

Moose Rapids

The Moose Rapids facility is owned by TransAlta Renewables. Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. This facility has been operating since 1997. Generation from this facility is sold to the IESO under a contract that terminates on December 31, 2030.

Ragged Chute

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of New Liskeard, in northern Ontario. We lease this facility from Ontario Power Generation Inc. and it has been operating since 1991. Generation from this facility is sold to the IESO under a contract that terminates on June 30, 2029. On January 6, 2016, TransAlta Renewables acquired from the Corporation tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows, in part, from the Ragged Chute Facility; subsequently, on November 30, 2016, the economic interest was replaced with direct ownership of the entity that owns the Ragged Chute hydro facility. See "Business of TransAlta – Non-Controlling Interests" in this AIF.

US Hydro Facilities

Skookumchuck

We own a 1 MW hydroelectric generating facility on the Skookumchuck River near Centralia, Washington, and related assets that are used to provide water supply to our generation facilities in Centralia. On December 10, 2010, we entered into an agreement with Puget Sound Energy for Skookumchuck to provide power until 2020.

US Coal Business Segment

Our U.S. Coal facilities are summarized in the following table:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)	Commercial Operation Date	Revenue Source	Contract Expiry Date
Centralia Thermal No. 1	WA	100	670	1971	LTC/Merchant	2020
Centralia Thermal No. 2	WA	100	670	1971	LTC/Merchant	2025
Total US Coal Net Capacity			**1,340**			

We own a two-unit 1,340 MW thermal coal-fired facility in Centralia, Washington, located south of Seattle. We have entered into a number of multiple year medium- and short-term energy sales agreements from the Centralia thermal plant. In 2011, Washington State passed the TransAlta Energy Transition Bill (chapter 180, Laws of 2011) (the "Bill") allowing the Centralia thermal plant to comply with the State's GHG emissions performance standards by ceasing coal generation in one of its two boilers by the end of 2020 and the other by the end of 2025. The Bill removed restrictions that had previously been imposed on the facility limiting the duration of new contracts from the facility and limiting the technology that the facility would be required to implement for NOx controls. On July 25, 2012, we announced that we

entered into an 11-year agreement to provide electricity from our Centralia thermal plant to Puget Sound Energy. The contract began in 2014 and runs until 2025 when the plant is scheduled to stop burning coal. Under the agreement, Puget Sound Energy bought 180 MW of firm, base-load power starting in December 2014. In December 2015, the contract volume increased to 280 MW and from December 2016 to December 2024 the contract is for 380 MW. In 2025, the contracted volume is for 300 MW.

On July 30, 2015, we announced that we were moving ahead with plans to invest US$55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The initiative is part of Centralia's transition from coal-fired operations in Washington, beginning on December 31, 2020. The US$55 million community investment is part of the Bill passed in 2011. The Bill was an agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State, closing Centralia facility's two coal units, one in 2020 and the other in 2025. Approved funding for the three boards totals approximately US$36.7 million as at December 31, 2019.

We sell electricity from the Centralia thermal plant into the Western Electricity Coordinating Council and, in particular, on the spot market in the U.S. Pacific Northwest energy market. Our strategy is to balance contracted and non-contracted sales of electricity to manage production and price risk.

We also own a coal mine adjacent to the Centralia facility. We stopped mining operations at our Centralia coal mine on November 27, 2006. Although we estimate that certain coal reserves remain to be extracted, we have not yet received permits for, nor developed the new area from which this coal could be produced. Coal to fuel the Centralia plant is sourced from the Powder River Basin in Montana and Wyoming. TransAlta is currently party to a coal contract that expires at the end of 2020. We expect to continue to source our future coal needs from the Powder River Basin. In December 2014, we began fine coal recovery operations at our Centralia mine. This operation recovers previously wasted coal as part of the mine reclamation process. On March 29, 2019, we sent a notice of termination to the contractor ("Coalview") performing the fine coal recovery operations. Coalview is disputing the termination. TransAlta filed a motion for summary judgment that is scheduled for April 20, 2020. We anticipate a judgment in the first half of 2020.

Under the U.S. Federal Mine Safety and Health Act, TransAlta must report all citations at its Centralia mine. The mine is currently not in operation. There was one injury incident at the mine during 2019, attributable to Coalview. The total dollar value of all Mine Safety and Health Administration ("MSHA") assessments are not material. There is one pending penalty assessment being contested by Centralia before the Federal Mine Safety and Health Review Commission involving the Centralia mine pending during 2019. Coalview is contesting two 104(d)(1) citations.

Mine or Operating Name/MSHA Identification Number	Total Number of Section 104 Violations for which Citations Received (#)	Total Number of Orders Issued Under Section 104(b) (#)	Total Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards Under Section 104(d) (#)	Total Number of Flagrant Violations Under Section 110(b)(2) (#)	Total Number of Imminent Danger Orders Issued Under Section 107(a) (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Initiated or Pending During Period (#)
4500416	27[1]	0	2[2]	0	0	156,413[3]	0	No	No	0

Notes:

(1) Four citations issued to Centralia (three are closed and one is being contested) and 23 issued to Coalview

(2) Both 104(d) citations were issued to Coalview

(3) $2,072 proposed assessment to Centralia ($1709 contested) and $154,341 proposed assessment to Coalview

Energy Marketing Segment

Our Energy Marketing segment provides a number of strategic functions, including the following:

- gathering and analyzing market trends to enable more effective strategic planning and decision making;
- negotiating and entering into contractual agreements with customers for the sale of output from our generation assets, including electricity, steam or other energy-related commodities;
- negotiating and managing fuel supply arrangements with third parties for our generation assets. This includes scheduling, billing and settlement of physical deliveries of natural gas and other fuels;
- the development and execution of our corporate hedging strategy within Board approved parameters; and
- the optimization of the asset fleet to maximize gross margin and mitigation of market risks.

The Energy Marketing segment also derives additional revenue by providing fee-based asset management services to third parties, by earning margins on third-party gas and power transactions, and by trading electricity and other energy commodities (i.e. fuels). The origination and trading activities are focused on the existing asset and customer footprint of the Corporation.

The segment seeks to measure and manage a number of risks for the assets and for our trading books. The key risk control activities of the Energy Marketing segment include the measurement and management of market, credit, operational, reputational, compliance and legal risks.

The segment uses Value at Risk ("VaR"), Gross Margin at Risk ("GMaR"), and tail risk measures to monitor and manage the risks within our asset and trading portfolios. VaR and GMaR measure the potential losses that could occur over a given time period due to changes in market risk factors. Back tests are used to provide further sensitivities to the market risks within the portfolio. Compliance, reputational and legal risks are managed within our legal and compliance policies, and monitoring tools are used to flag compliance risks. The Energy Marketing segment actively manages the risks within approved limits and our policies.

Corporate Segment

Our Corporate segment includes the Corporation's central finance, legal, administrative, business development and investor relations functions.

Non-Controlling Interests

Our subsidiaries and operations in which we have non-controlling interests are as follows:

TransAlta Renewables

As of December 31, 2019, we held, directly and indirectly, approximately 60 per cent of the issued and outstanding common shares in TransAlta Renewables, which is a publicly traded entity. During 2019, our ownership interest was reduced from approximately 61 per cent at December 31, 2018, due to additional common shares issued by TransAlta Renewables under its Dividend Reinvestment Plan. We remain committed to maintaining our position as the majority shareholder of TransAlta Renewables.

TransAlta Corporation provides all management, administrative and operational services required for TransAlta Renewables to operate and administer its assets and to acquire additional assets pursuant to the Management, Administrative and Operational Services Agreement between TransAlta Corporation and TransAlta Renewables. In connection with the services provided under the Management, Administrative and Operational Services Agreement, TransAlta Renewables pays us an annual fee, which is meant to cover our management, administrative, accounting, planning and other head office costs we incur in connection with providing services to TransAlta Renewables under the Management, Administrative and Operational Services Agreement (the "G&A Reimbursement Fee"). The G&A Reimbursement Fee is payable in equal quarterly installments. As at December 31, 2019, the G&A Reimbursement Fee was approximately $17 million. On February 28, 2020, the Management Agreement was amended so that the G&A Reimbursement Fee will be calculated quarterly in an amount equal to 5 per cent of Comparable EBITDA of the immediately prior fiscal quarter, without duplication for any indirect costs associated with the management, administrative, accounting, planning and other head office costs of TransAlta that reduce the dividends or distributions that would otherwise be payable to the Corporation on any of the tracking preferred shares. This amendment is not expected to result in any material change to the amount of the G&A Reimbursement Fee.

TransAlta Renewables completed its initial public offering in August 2013. In connection with the offering, we transferred to TransAlta Renewables certain wind and hydro power generation assets. On December 20, 2013, we sold to TransAlta Renewables an economic interest in a 140 MW wind farm located in the State of Wyoming for payment equal to US$102 million. The Wyoming wind farm is managed by TransAlta under the terms of the Management, Administrative and Operational Services Agreement and is operated by NextEra Energy Resources, LLC.

On May 7, 2015, we sold to TransAlta Renewables an economic interest based on the cash flows of our Australian assets. The portfolio, held by TEA, consists of six operating assets with an installed capacity of 450 MW as well as a 270 km gas pipeline. The combined value of the Australian transaction was approximately $1.78 billion. At the closing of the Australian transaction, TransAlta Renewables paid us $216.9 million in cash as well as approximately $1,067 million through the issuance of a combination of common shares and Class B shares in the capital of TransAlta Renewables. On August 1, 2017, the Class B shares converted into common shares in the capital of TransAlta Renewables.

On January 6, 2016, we sold to TransAlta Renewables an economic interest in the Corporation's Sarnia cogeneration plant, Le Nordais wind farm and Ragged Chute hydro facility for a combined value of $540 million. The Canadian assets consist of approximately 611 MW of contracted power generation assets located in Ontario and Québec. The Corporation received cash proceeds of $172.5 million, a $215 million convertible unsecured subordinated debenture and approximately $152.5 million in common shares of TransAlta Renewables. In November 2016, the economic

interest was converted to direct ownership of the entities that own the Sarnia cogeneration plant, Le Nordais wind farm and Ragged Chute hydro facility. The convertible debenture was redeemed on November 9, 2017.

On May 31, 2018, we sold to TransAlta Renewables an economic interest in the Corporation's 50 MW Lakeswind Wind Farm in Minnesota and 21 MW of solar projects located in Massachusetts. In addition, we sold to TransAlta Renewables the 20 MW Kent Breeze Wind Farm located in Ontario. The total purchase price payable to TransAlta for the three assets, which have an average weighted contract life of 15 years, was $166 million, including the assumption by TransAlta Renewables of $62 million of tax equity obligations and project debt.

The Management, Administrative and Operational Services Agreement has an initial 20-year term; provided, however, that the agreement shall be automatically renewed for further successive terms of five years after the expiry of the initial term or any renewal term, unless terminated by either party not less than 180 days prior to the expiration of the initial term or any renewal term, as the case may be. The Management, Administrative and Operational Services Agreement may be terminated by: (a) mutual agreement; (b) TransAlta Renewables upon the occurrence of a material default by TransAlta; and (c) TransAlta (i) upon the occurrence of a material default by TransAlta Renewables or (ii) upon a "Change of Control" of TransAlta Renewables, being the acquisition by any person or group of persons acting jointly and in concert (other than us and our affiliates) of more than 50 per cent of the issued and outstanding common shares. In addition, the Management, Administrative and Operational Services Agreement may be terminated by TransAlta Renewables by a majority vote of our independent directors at any time if TransAlta's direct and indirect ownership in TransAlta Renewables falls below 20 per cent.

Kent Hills

We indirectly hold, through our share ownership of TransAlta Renewables, an 83 per cent interest in the 150 MW Kent Hills 1 and 2 wind farm located in New Brunswick. We also indirectly hold, through our ownership of TransAlta Renewables, an 83 per cent interest in the 17.25 MW expansion of the Kent Hills site (Kent Hills 3) which was completed on October 19, 2018, bringing the total generating capacity of the three Kent Hills facilities to 167 MW. A description of the facilities is provided under the hearing "*General Development of the Business – Three-Year History - Generation and Business Development*".

TA Cogen

We hold a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent ownership is held by Canadian Power Holdings Inc., a subsidiary of CK Infrastructure Holdings Limited.

TA Cogen holds a 50 per cent interest in the 790 MW Sheerness thermal generation facility in Alberta and the 118 MW Fort Saskatchewan natural gas-fired cogeneration facility in Alberta. TA Cogen also holds an interest in three natural gas-fired cogeneration facilities located in Ontario: (i) the 108 MW Mississauga Facility, currently in the process of decommissioning, see "*General Development of the Business – Three-Year History - Generation and Business Development*"; (ii) the 74 MW Ottawa plant; and (iii) the 72 MW Windsor plant. Descriptions of these facilities, ownership levels and contract expiry dates are provided under the headings "*Canadian Gas Business Segment"* and *"Canadian Coal Business Segment*" in this AIF.

PPAs

Renewables PPAs

In August of 2013, we entered into long-term power purchase agreements with certain subsidiaries of TransAlta Renewables (each a "Merchant Subsidiary") providing for the purchase by TransAlta, for a fixed price, of all of the power produced at the Merchant Subsidiaries (the "Renewables PPAs"). The initial price payable in 2013 by TransAlta for output under the Renewables PPAs was $30.00/MWh for wind facilities and $45.00/MWh for hydroelectric facilities, which amounts are adjusted annually for changes in the Canadian consumer price index. The Canadian consumer price index adjusted prices for 2019 were $32.88 per MWh for wind facilities and $49.33 per MWh for hydroelectric facilities. Under the terms of each Renewables PPA, the Merchant Subsidiary is under no obligation to deliver any specified amount of energy and, in no event, shall any penalties or curtailment payments be payable under the Renewables PPA. The Merchant Subsidiary will assume all operating and generating risk and TransAlta will only be required to purchase power that is actually produced.

Each Renewables PPA has a term of 20 years or end of asset life, where end of asset life is less than 20 years. Each Renewables PPA may be terminated by: (a) the mutual agreement of the parties; (b) the Merchant Subsidiary upon the occurrence of a material default by TransAlta; and (c) TransAlta (i) upon the occurrence of a material default by the Merchant Subsidiary; (ii) upon a change of control of TransAlta Renewables; or (iii) upon a change of control of the Merchant Subsidiary.

Alberta PPAs

A number of our Alberta thermal and hydroelectric facilities are operated under Alberta power purchase arrangements ("Alberta PPAs"). The Alberta PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each thermal plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which electricity is to be supplied. We bear the risk or retain the benefit of availability under or above a targeted availability (except for those arising from events considered to be force majeure, in the case of the PPA thermal plants) and any change in costs (unless due to a change in law) required to maintain and operate the facilities.

In early 2016, the buyers gave notice to the Balancing Pool of the termination of the Alberta PPAs for Sundance A, B, and C, Sheerness, and Keephills. The Balancing Pool confirmed the terminations of the PPAs for Sundance A, B, C, and Sheerness in late 2016 and confirmed the termination of the Keephills PPA in late 2017. For those Alberta PPAs that were terminated, the Balancing Pool had assumed the role of buyer. On September 18, 2017, the Balancing Pool elected to terminate the Sundance B PPA and Sundance C PPA effective on or before March 31, 2018. Pursuant to a written agreement, the Balancing Pool paid us approximately $157 million on March 29, 2018. We disputed the termination payment received as the Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation. On August 26, 2019, we announced that we were successful in the arbitration and received the full amount claimed by us to have been owing, being $56 million, plus GST and interest. See "*General Development of the Business - Three-Year History - Generation and Business Development*".

Our hydroelectric facilities, other than Belly River, Pocaterra, St. Mary, Taylor and Waterton, are aggregated through one Alberta PPA that provides for financial obligations for energy and ancillary services based on hourly targets. We meet these targeted amounts through physical delivery or third-party purchases.

Competitive Environment

Power generation is an industry in the midst of an exciting transformation and the demand for electricity is expected to grow significantly over the long-term. In addition to the need to keep pace with ongoing demand growth for electricity, there are several key factors driving the need for significant investment in new generating capacity going forward. First, coal-based generation is being retired. These retirements are being driven by asset age as well as government policy that places a price on emissions and, in some cases, mandates the retirement of these assets. Second, government policies that impose costs or provide incentives for lower emission technologies are creating opportunities for renewable generation technologies. These opportunities are coinciding with a significant decline in the installed costs of both wind and solar generation. As a result, these technologies now account for the majority of the new generating capacity added to many of the world's electricity grids. Third, electrification is seen as a one of the most effective levers to reduce GHG emissions in many sectors such as transportation. As these sectors and others continue to shift to electricity as their primary energy source we will see accelerating demand growth for our product.

We expect that renewable power generation will be one of the fastest growing sources of power generation in both Canada and the US, a forecast that is well supported by recent trends and announcements. We are ready for this transformation. We have the skills, experience and scale to compete for additional assets within our target markets. Today, we are one of the largest publicly traded renewable power generation companies in Canada.

Alberta

The *Fair, Efficient and Open Competition Regulation* generally provides that an electricity market participant shall not hold offer control in excess of 30% of the total maximum capability of generating units in Alberta. A market participant's total offer control is measured as the ratio of MW under its control to the sum of maximum capability of generating units in Alberta. Our market share of offer control in Alberta in 2019 was approximately 21 per cent (16 per cent if the Sundance mothballed units are excluded from offer control).

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

Coal-to-Gas Conversions

The Corporation's coal-to-gas conversion plan offers compelling economics and we believe it is an attractive value proposition that compares favourably to the risk/return metrics of greenfield or brownfield investments or compared to staying on coal. During 2019, we made significant advances in our planning for the coal-to-gas conversion program and

this conversion is now well underway. We have announced that during the 2020/2021 period Sundance 6 and Keephills Unit 2 will undergo conversions to allow them to burn natural gas in the existing boilers instead of coal, and Keephills 3 will be converted to allow it to burn natural gas or coal. Further, we will repower the Sundance 5 plant by installing new gas turbines and boilers and using the existing steam turbine. We are evaluating this same repowering approach for Keephills Unit 1. In November 2019, we announced the acquisition of two Siemens 'F' Class gas turbines from Kineticor originally planned to be commissioned at Kineticor's Three Springs project in Northern Alberta.

With lower capital investment and lower sustaining costs, and being able to operate significantly longer once converted, TransAlta will enhance and extend the cash flows from the Alberta coal fleet through these conversions. Following the conversion to gas-fired generation, we will also significantly improve our environmental performance as GHG, air emissions, waste generation and water usage will all significantly decline. A conversion of coal-fired power generation to gas-fired generation is also expected to eliminate all mercury emissions and the majority of sulphur dioxide emissions as well as halving nitrogen oxide emissions.

US Pacific Northwest

Our capacity in the US Pacific Northwest is represented by our 1,340 MW Centralia coal plant. In the second quarter of 2020, we expect to add the Skookumchuck wind farm. This asset is currently under construction by Southern Power and when the project reaches commercial operation, we anticipate purchasing a 49% interest in the asset. The Centralia coal facility is committed to be phased-out over the next five years with half of the plant capacity scheduled to retire at the end of 2020 and the other half at the end of 2025.

System capacity in the region is primarily comprised of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited and further constrained by an emphasis on energy efficiency. We expect to see significant change in this market over the next decade as coal generation is retired and renewable portfolio standard requirements continue to strengthen.

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

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

Contracted Gas and Renewables

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

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

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

Australia

The Australian electricity industry is divided among three distinct markets, the National Electricity Market (NEM) in the East, the Wholesale Electricity Market (WEM) in Western Australia and the Northern Territory Electricity Market. In addition, a there is a significant market for "off-grid" generation supporting remote communities and remote mining operations, particularly in Western Australia, Queensland and the Northern Territory.

The NEM is the largest market in Australia, currently with over 53 GW of installed capacity. The installed capacity based on coal generation is about 23 GW and much of this is expected to retire over the next decade due to the age of these assets. Renewables penetration, both wind and solar, has grown strongly in this market and that is expected to continue. The federal Department of Environment and Energy predicts an overall renewables penetration of 50% in the NEM and 55% in the WEM by 2030.

Our business today is solely in Western Australia and focused on the large remote mining industry in that State. The primary exports from Western Australia are iron ore, nickel and gold and these three industries are all performing well. Commodity prices are strong, and the nickel industry is experiencing an increase in demand to support both steel and battery manufacturers. Iron ore exports are forecast to rise slightly driven by large-scale producers ramping up long term production targets to maintain revenue in a lower price environment. Remote mining operations are also beginning to explore options to add renewable generation to their sites in an effort to reduce the amount of gas and diesel required in these operations. We expect this trend to continue and to create opportunity for our business in Western Australia.

Seasonality and Cyclicality

The business of the Corporation is cyclical, particularly in respect of the renewables generation held by TransAlta Renewables, due to: (i) the nature of electricity and the limited storage capacity ; and (ii) the nature of wind, solar and run-of-river hydroelectric resources, which fluctuate based on both seasonal patterns and annual weather variation.

Typically, run-of-river hydroelectric facilities and solar facilities generate most of their electricity and revenues during the spring and summer months when the melting snow starts feeding the watersheds and the rivers and the sun is at its highest peak. Inversely, wind speeds are historically greater during the cold winter months when the air density is at its peak. TransAlta Renewables' strategy of technological and geographical diversification reduces the Corporation's exposure to the variations of any one natural resource in any one region. Since TransAlta Renewables' operations are presently based mainly on power generation from wind, its financial results in any one quarter may not, however, be representative of all quarters. See *"Risk Factors*".

Regulatory Framework

Below is a description of the regulatory framework in the markets that are material to the Corporation.

Canadian Federal Government

In November 2016, the Canadian federal government announced that coal-fired generation would be phased out by 2030, following a similar commitment by the Alberta provincial government in November 2015. These decisions changed the coal plant closure requirements, which had previously been guided by federal regulations that became effective on July 1, 2015, which provided for up to 50 years of life for coal units. On February 16, 2018, Environment and Climate Change Canada announced draft regulations to phase out coal-fired generation by 2030, as well as draft regulations for gas-fired electricity generation including provisions for the conversion of boiler units from coal-fired generation to natural gas-fired generation. Please refer to "*Environmental Risk Management - Ongoing and Recently Passed Environmental Legislation*" for more information.

Alberta

Since January 1, 1996, new generating capacity initiatives in Alberta have been undertaken by independent power producers ("IPP") and have been subject to market forces, rather than rate regulation. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator ("AESO"), based upon offers by generators to sell power. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell power. The Market Surveillance Administrator for the Province of Alberta is an independent entity responsible for monitoring and investigating the market behaviour of market participants, including the AESO and the Balancing Pool, and enforcing compliance with all applicable legislation, regulations, AESO and Alberta Utilities Commission ("AUC") rules. The AUC oversees electricity industry matters, including new power plant and transmission facilities, the distribution and sale of electricity and retail natural gas. The AUC is also responsible for approving the AESO's rules and for determining penalties and sanctions on any participant found to have contravened market rules.

On July 24, 2019, the Government of Alberta announced that it will not transition to a capacity market and will continue with an energy-only market design. This decision stopped all work on the capacity market design work, which had been underway through the AESO since 2017. The Government's announcement followed a stakeholder consultation and review that found stakeholder support for maintaining the energy-only market based upon its proven track record for providing a reliable supply and affordable electricity for Albertans. The removal of legislative changes to enable the capacity market received royal assent on October 31, 2019.

The Minister of Energy further directed Alberta Energy to conduct a policy review on market power and market power mitigation in the energy-only and ancillary services market and directed the AESO to conduct analysis and make recommendations on whether changes are needed to the price floor/ceiling and shortage pricing by July 31, 2020. The outcomes of these reviews are ongoing and no changes to the energy-only market have been proposed to-date.

Ontario

Ontario's electricity market is a hybrid market that includes a wholesale spot electricity market, as well as regulated prices for certain electricity consumers and long-term contracts for the purchase of power by the IESO from power producers. The IESO is the successor organization resulting from the merger of the former IESO and Ontario Power Authority (OPA) in 2015. The Ontario Ministry of Energy, Northern Development and Mines supports the IESO in defining the electricity mix to be procured by the IESO. The IESO has the mandate to undertake long-term planning of the electric system, to procure the electricity generation in that plan and to manage contracts for privately owned generation. The IESO is responsible for managing the Ontario wholesale market and for ensuring the reliability of the electric system in Ontario. The electricity sector is regulated by the Ontario Energy Board.

The IESO commenced a market renewal consultation which includes proposed fundamental changes to the electricity market. These include modifying the energy market, adding a capacity market and improving operability and reliability. The IESO is planning to implement a capacity auction starting in 2020. The IESO is continuing to consult on changes to the energy market that are expected to be implemented in early 2023.

British Columbia

British Columbia's electricity market is dominated by a vertically integrated Crown corporation - BC Hydro. The other provincial utility, FortisBC, has a small service territory in the interior of the province. Electricity is traded with other markets through BC Hydro's trading arm and wholly owned subsidiary, Powerex. All electricity utilities are regulated by the British Columbia Utilities Commission.

Under government direction in the late 1990's and early 2000's, BC Hydro established a private power market through several competitive calls for power from independent power producers. In recent years, BC Hydro stopped its competitive power calls and contracting with independent power producers ("IPPs") and also suspended its smaller Standing Offer Program for small projects below 15 MW pending a review of the program and the completion of the 2018 Integrated Resource Plan ("IRP").

BC Hydro is working on its 2018 IRP to determine its supply needs and future purchase strategies. The 2018 IRP is delayed and may not be delivered for consideration by the BC Utilities Commission until 2021. The 2013 IRP outlined a need to renew contracts with existing independent power facilities but did not identify a need for new IPPs and little in the market has changed since the adoption of the 2013 IRP.

Québec

The Régie de l'énergie is Québec's regulatory authority with primary jurisdiction over the economic regulation of the electricity sector. Québec is served principally by Hydro-Québec, a government-owned entity with highly competitive hydroelectric resources. It has an almost exclusive right to distribute electricity throughout the Province of Québec. Most of Hydro-Québec's generation stations are located substantial distances from consumer centres. As a result, Québec's transmission system is one of the most extensive and comprehensive in North America, comprising more than 33,000 kilometres of lines. In May 2006, the Québec government released an energy strategy that requires private developers to partner with local communities in order to develop energy projects. In all cases, an agreement with Hydro-Québec on the price of the electricity produced is required before a project can obtain governmental approval.

New Brunswick

In 2004, New Brunswick enacted the *Electricity Act* (New Brunswick), pursuant to which the province's electricity market changed to enable the creation of a competitive environment for eligible wholesale, industrial and municipal utility customers. The *Electricity Act* (New Brunswick) provides that, as generating assets are retired or as additional supply is required, standard service suppliers (i.e., the distribution companies) will procure new supply through the competitive market. This means that any new resources required by New Brunswick Power Distribution Company will be acquired through procurement processes open to both IPPs as well as the New Brunswick Power Generation Company. The province has indicated its decision to increase New Brunswick's Renewable Portfolio Standard to a minimum of 40 per cent of New Brunswick Power Generation Company in-province sales by 2020.

As directed by the 2011 New Brunswick Energy Blueprint and 2014 Integrated Resource Plan, this goal will be accomplished through a combination of eligible renewable energy imports from other provinces and by purchased power from local producers and customers through a variety of programs. In 2015, regulations under the *Electricity Act* (New Brunswick) were amended to support the 40 per cent renewable portfolio standard.

While New Brunswick has procured large commercial wind projects over the last decade, the provincial government has signaled in its 2015 document, Future Development of our Renewable Energy Resources, that the next phase of renewable development will focus on smaller scale projects with a particular emphasis on non-intermittent forms of generation such as wood-based biomass.

US Wholesale Power Market

The Federal Power Act gives the Federal Energy Regulatory Commission ("FERC") rate-making jurisdiction over public utilities engaged in wholesale sales of electricity and the transmission of electricity in interstate commerce. The Federal Power Act also provides FERC with the authority to certify and oversee an electric reliability organization which promulgates and enforces mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified the North American Electric Reliability Corporation ("NERC") as the electric reliability organization. NERC has promulgated mandatory reliability standards, and, in conjunction with the regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

Minnesota (MISO)

Lakeswind in Minnesota is connected to the Midwest Independent System Operator (MISO) and falls under FERC jurisdiction. FERC-approved MISO tariffs dictate market and operational requirement for facilities. MISO has both an energy market and a voluntary capacity market. Under the long-term contract, all power is delivered at the plant-gate, ensuring market changes should have an immaterial impact on revenues.

Massachusetts (NE-ISO)

The Massachusetts Solar projects are connected to the distribution grid so their generated electricity flows directly to the utility and is not offered into the integrated market. All revenues associated with this project flow from the State's net metering and Renewable Energy Portfolio Standard programs. Market changes are not expected to have a material impact on net metering revenues.

New Hampshire (NE-ISO)

Antrim in New Hampshire is connected to the New England Independent System Operator (NE-ISO) and falls under FERC jurisdiction. FERC-approved NE-ISO tariffs dictate market and operational requirements for facilities. The NE-ISO has both an energy and a mandatory participation capacity market. Antrim's electricity is offered into the market and transferred to the buyers. Antrim has a long-term capacity supply obligation so is not impacted by near-terms changes to the capacity market auction process. As Antrim and most other intermittent wind projects must take part in the NE-ISO's Do Not Exceed Dispatch, market changes are enot expected to have a material impact on revenues.

Pennsylvania (PJM)

Big Level in Pennsylvania is connected to the PJM ISO and falls under FERC jurisdiction. FERC-approved PJM tariffs dictate market and operational requirements for facilities. PJM has both an energy and a mandatory participation capacity market. All attributes, energy and capacity have been transferred to the buyer. As a result, market changes are not expected to have an material impact on revenues.

Washington

The Washington Transportation and Utilities Commission has the power to regulate and supervise every "public utility," which includes investor-owned electric utilities. For regulated electric utilities, the commission approves regulated rates, reviews integrated resource plans, approves mergers and acquisitions and grants certificates of public convenience and necessity for large facilities (e.g. power plants and transmission lines). Centralia is not regulated by the commission as it only sells wholesale electricity and does not sell retail electricity in the state. Only FERC and NERC requirements apply to the facility. As a result, the Corporation does not expect any material impacts on revenue streams from any commission decisions.

Wyoming

The Wyoming Public Service Commission has the power to regulate and supervise every "public utility," which includes the four investor-owned electric utilities in Wyoming, as well as certain natural gas, electric, telecommunications, water and pipeline services. For regulated electric utilities, the commission approves regulated rates, reviews integrated resource plans, approves mergers and acquisitions and grants certificates of public convenience and necessity for large facilities (e.g. power plants and transmission lines). Wyoming Wind is not regulated by the commission as it only sells wholesale electricity and does not sell retail electricity in the state. Only FERC and NERC requirements apply to the facility. As a result, the Corporation does not expect any material impact on revenue streams from any commission decisions.

Australia

Australia has two separate major electricity markets, the National Electricity Market ("NEM") encompassing all the major population centres on the Eastern seaboard, and the Wholesale Electricity Market ("WEM") covering the southwest of Western Australia including its capital city, Perth. A number of smaller, stand-alone electricity grids serve

regional population centres including the North West Interconnected System ("NWIS") in the Pilbara region of Western Australia and the Darwin-Katherine System in the Northern Territory.

The Australian Energy Market Operator ("AEMO") is the market operator for both the WEM and the NEM. The two markets are completely independent of each other having different market rules and no physical interconnection between them. The WEM includes both a market for generation capacity and a gross pool to trade energy with a single reference node for wholesale prices. The NEM is a pure energy-only market with five regional reference nodes for wholesale prices corresponding to each of the participating states of Queensland, New South Wales, Victoria, Tasmania and South Australia.

The Public Utilities Office of Western Australia ("PUO") in its capacity as advisor to the Minister for Energy is currently working with AEMO and the wider electricity industry to implement further reforms to the WEM including introducing constrained network access and required consequential amendments to the wholesale market rules to allow for security constrained dispatch. A comprehensive program of works is currently underway with a goal of implementing reforms on October 1, 2022.

The PUO is also working with participants in the NWIS to introduce some elements of a more formal electricity market, including providing third party access to the Horizon Power owned part of the NWIS and providing centralized coordination of dispatch and ancillary services**.**

Competitive Strengths

We believe that we are well positioned to achieve our business strategy due to our competitive strengths, which include the following:

Operating Strength

We continually benchmark ourselves against previous year performance in order to drive operating costs lower year over year, while also maintaining strong levels of generation performance. We have implemented a program to drive incremental value from our fleet through the development of initiatives to improve generating equipment efficiencies, refining processes and procedures, and optimizing cost structures. Our Sarnia Cogeneration Plant has demonstrated industry best practices through several operations and maintenance processes including the work management process and Environmental, Health & Safety scorecard. We believe the continued maturity of these programs will continue to drive further value in the operations of our facilities.

Stable Cash Flow Base

Through the use of Alberta PPAs and long-term contracts, approximately 71 per cent of our capacity is contracted in 2020 and approximately 49 per cent in 2021. The net revenue received under these contractual arrangements helps to minimize short-term revenue fluctuations due to the variable price of electricity.

Fuel Diversity

We have an interest in a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, wind, and solar. We believe that this mix reduces the impact on our performance in the event of external events affecting one fuel source.

Management Team and Employee Experience

Our management team has substantial industry, international, investment and market experience. The experience and acumen of our employees further enhances our capital value creation. Our business has been operating for over 100 years, and many of our employees have been with us for more than 30 years.

Energy Marketing Expertise

We believe that our Energy Marketing segment has enhanced returns from our existing generation base and has allowed us to obtain more favourable pricing for uncommitted electricity, secure fuel supply on a cost-effective basis and fulfill electricity delivery obligations in the event of an outage.

Wind Generation

Through our ownership interest in TransAlta Renewables, we are one of the largest owners and operators of wind generation in Canada. Our management team has developed key relationships with customers, suppliers and policy makers that provide a competitive advantage in the development, operations and marketing of wind generation.

Environmental, Social and Governance

We are a recognized leader in sustainable development and we have taken early preventative action on a number of environmental fronts in advance of regulation. We have a long history of adopting leading sustainability practices, including 25 years of sustainability reporting and voluntarily integrating our sustainability report into our annual report. We have been issuing an integrated annual report since 2015. We test our practices and our reporting against standards set by CDP (formerly the Carbon Disclosure Project), the Task Force on Climate-related Financial Disclosures and the Canadian Council for Aboriginal Business. In 1990, we were the first Canadian company to purchase carbon offsets and in 2000 we were an early adopter of wind power generation. Through our ongoing transformational efforts, we have reduced our total GHG emissions by 21.3 million tonnes since 2005.

ENVIRONMENTAL RISK MANAGEMENT

We are subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of electrical and thermal energy and surface mining. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business. For further details, see below and "*Risk Factors*".

Canadian Federal Government

Federal Carbon Pricing on GHG

On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. The price began at $20 per tonne of carbon dioxide equivalent ("CO_2e") emissions in 2019, and rises by $10 per year until reaching $50 per tonne in 2022. In 2022, there will be a review of the Output-Based Pricing Standard ("OBPS") and other aspects of the GGPPA.

The OBPS regulates large emitters' carbon intensity by setting a sectoral performance standard (benchmark) of GHG emissions per unit of production. Emitters exceeding the benchmark generate carbon obligations and those emitters that perform below the benchmark generate emission performance credits (EPCs). Emitters can meet their obligations by reducing their emission intensity, buying carbon credits from others (offsets or EPCs) or making compliance payments to the government.

On January 1, 2019, the GGPPA's backstop mechanisms came into force in provinces and territories that did not have an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system. The backstop mechanism has two components: the federal pollution pricing fuel charge ("Carbon Tax") and the regulation for large emitters, OBPS. The Carbon Tax sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources. Provinces and territories captured by the OPBS include Ontario, Manitoba, New Brunswick, Saskatchewan, Prince Edward Island, Yukon and Nunavut. Provinces and territories subject to the Carbon Tax include Alberta, Ontario, Manitoba, Saskatchewan, Prince Edward Island, Yukon and Nunavut.

Other jurisdictions that were compliant with the GGPPA did not have the backstop mechanism imposed in 2019. These jurisdictions must file and have their carbon pricing programs approved annually. Over future annual compliance periods, if parts or all of a province's GHG regulations fall out of compliance with the GGPPA, the federal government will impose its backstop mechanisms.

In *Reference re Greenhouse Gas Pollution Pricing Act*, the Court of Appeal of Alberta held that Parts 1 and 2 of the GGPPA are unconstitutional in their entirety. This decision is the first time that a court has found the GGPPA to be unconstitutional. In split decisions released last year, both the Court of Appeal for Ontario and the Court of Appeal for Saskatchewan concluded that the GGPPA is constitutional. The Supreme Court of Canada is set to determine the matter following the hearing of the appeals in 2020.

Federal Pollution Pricing Fuel Charge ("Carbon Tax")

On October 31, 2018, the Ontario Government passed the *Cap and Trade Cancellation Act* (Ontario) repealing its carbon levy. The Canadian federal government replaced the repealed Ontario carbon levy with the Carbon Tax on January 1,

2019. The Alberta government repealed the Alberta carbon levy (i.e., carbon tax) on May 30, 2019. The federal government replaced the repealed carbon levy with the Carbon Tax effective January 1, 2020.

Alberta and Ontario facilities that are covered by the large emitter regulations are exempt from the Carbon Tax. The Carbon Tax only applies to transportation and heating fuels used at renewables facilities and has a negligible cost impact for the Corporation.

Gas Regulation

On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. Under the regulations, new and significantly modified natural gas-fired electricity facilities with a capacity greater than 150 MW must meet a standard of 0.420 tonne of carbon dioxide equivalent ("tCO_2e") per megawatt hour ("MWh") to operate. For units with a capacity between 150 MW and 25 MW, their standard was set at 0.550 tCO_2e/MWh. For units of 25 MW or less, there is not standard.

Under the regulations, coal-to-gas conversions will also eventually have to meet a standard of 0.420 tCO_2e/MWh. If the first year performance test after conversion meets certain emission standards it will not have to meet the 0.420 tCO_2e/MWh standard for several additional years past the end of its useful life.

Coal Regulation

On December 12, 2018, amendments to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* came into force under the *Canadian Environmental Protection Act, 1999*. The amended regulations will require coal units to meet an emission level of 0.420 tCO_2e/MWh by the earlier of end-of-life under the 2012 regulations or December 31, 2029.

Clean Fuel Standard

In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard ("CFS") to reduce Canada's GHG emissions through the increased use of lower carbon fuels, energy sources and technologies. The objective of the regulation is to achieve 30 million metric tonnes of annual reductions in GHG emissions by 2030. The CFS will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. Under the proposed policy, coal combusted at facilities that are covered by coal-fired electricity regulations will be exempt from the regulation. Natural gas used for electricity production is currently expected to be included under the gaseous stream.

Consultation on the gaseous stream began in 2019 and will continue into 2020. The draft regulations for the gaseous stream are expected to be published in late 2020 with final regulations expected in 2021. The gaseous stream is currently expected to come into force by 2023. TransAlta continues to be engaged in the consultation process.

If a CFS standard is adopted for natural gas, the compliance requirements for natural gas suppliers will increase the input costs of natural gas. The Corporation expects that the change in law provisions contained in many of our contracts should result in no material revenue impacts to the Corporation.

Alberta

Large Emitter Greenhouse Gas Regulations

On January 1, 2018, the Alberta government transitioned from the *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 or sectoral performance compliance standard. The CCIR price was \$30/tCO_2e in 2019. The electricity sector performance standard was set at 0.370 tCO_2e/MWh and set to decline annually. All renewable assets that received crediting under the SGER continued to receive credits under CCIR on a one-to-one basis. All other renewable assets that did not receive credits under the previous standard that opted-in to the CCIR received carbon crediting up to the electricity sector performance standard under the CCIR until the end of 2019. Once wind projects' crediting standard under SGER protocol ends, these projects would also be able to opt into the CCIR system and be credited up to the performance standard.

On April 16, 2019, the United Conservative Party ("UCP") won the Alberta provincial election with a majority government. The UCP committed to move from the CCIR to a new regulation called the Technology Innovation and Emissions Reduction ("TIER") regulation. TIER replaced CCIR effective January 1, 2020. For the electricity sector, there were negligible changes between CCIR and TIER with renewable facilities continuing to receive crediting. The carbon prices for TIER in 2020 will remain at \$30/tCO2e but Alberta has not yet confirmed future price increases in line with federal requirements. The performance standard benchmark remained at 0.370 tCO2e/MWh. A review of TIER is not expected until 2023.

Facilities with emissions above the set benchmark will need to comply with TIER by: (i) paying into the TIER Fund; (ii) making reductions at their facility; (iii) remitting emission performance credits from other facilities; or (iv) remitting emission offset credits.

As required by the GGPPA, the Alberta government filed the TIER program details with the federal government. TIER was passed by the Alberta government on October 29, 2019 and on December 6, 2019 the federal government accepted the TIER regulation as compliant with the GGPPA for 2020.

TransAlta's thermal facilities attract compliance costs due to the carbon intensity associated of these facilities being above the TIER benchmark. TransAlta's renewable facilities generate carbon credits under TIER that are marketed to help mitigate carbon costs.

British Columbia

Beginning April 1, 2018, BC increased its carbon tax price to $35/tCO$_2$e and committed to raise the price $5 per year until it reaches $50 per tonne in 2021. The tax has a negligible cost impact for the Corporation due to the nature of our assets in B.C.

Ontario

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

Large Emitter Greenhouse Gas Regulations

The Canadian federal GGPPA requires provinces to have GHG regulations and prices in place that align with the GGPPA. On October 23, 2018, the federal government announced that Ontario large emitters would be subject to the federal backstop OBPS regulation as of January 1, 2020. All covered industry facilities with annual emissions over 50,000 tCO_2e are automatically covered with an opt-in provision for those emitters between 10,000 and 50,000 tCO$_2$e annually.

Ontario large emitters are currently subject to the federal backstop OBPS regulation.

On July 4, 2019, the Government of Ontario released the final regulations for the provincial Greenhouse Gas Emissions Performance Standards ("EPS"). The EPS establishes GHG emission limits on covered facilities. Large emitters generating over 50,000 tonnes CO2e ("tCO_2e") or more per year will be covered with an opt-in provision for those emitters between 10,000 and 50,000 tCO_2e annually. The carbon emissions limit for electricity is set at 420 tCO$_2$e/GWh. The program also provides a method that accounts for the carbon efficiency of cogeneration units. The federal government has not accepted the EPS as compliant with the GGPPA and the OBPS remains in force for reporting purposes for 2019 obligations.

Facilities with emissions above the set reduction requirements can comply by: (i) buying excess emission units from the regulator; (ii) making reductions at their facility; or (iii) using emission performance units generated by facilities emitting below their emission intensity limit. The first compliance period under the EPS will begin on January 1 in the year in which Ontario is removed from the list of provinces to which the federal OBPS applies. Ontario has submitted the EPS for federal review.

Most of our carbon costs flow through to our contract counterparties due to change of law provisions within our contacts.

Federal Pollution Pricing Fuel Charge ("Fuel Charge")

The federal government replaced the repealed Ontario carbon levy with the Fuel Charge on January 1, 2019. Ontario facilities covered by OBPS are exempt from the Fuel Charge.

Massachusetts

The Solar Renewable Electricity Credit I (SREC I) program carved out from Massachusetts' Renewable Portfolio Standard (RPS) an initial quantity of 400 MW from small solar facilities of 10 MW or less. The initial SREC I program size was expanded then replaced by a lower valued SREC II program. In 2018, the solar incentive program evolved into the current Solar Massachusetts Renewable Target Program that further reduced the incentive levels.

The initial SREC I program's volume target was achieved, and qualified projects under SREC I continue to generate SREC I credits for their first 10 years post-commercial operations date. SREC I facilities then generate Class 1 RECs under the Massachusetts RPS for the remainder of their operational life.

Under Massachusetts' net metering program, qualified facilities connect with the local utility and generate net metering credits. Net metering credits offset the delivery, supply and customer charges and can be sold to customers from remote or on-site qualifying facilities. In 2016, the net metering program was updated to reduce the value of the net metering credits by reducing the offset to only energy costs. New projects are impacted once the net metering program volume reaches 1,600 MW. Existing facilities were grandfathered and continue to receive the full, original cost offset treatment for a period of 25 years from initial commercial operations date. TransAlta generates approximately $10 to $12 million annually.

Minnesota (MISO)

Minnesota has an RPS and allows Michigan RECs to be used by utilities and non-utilities to meet the requirement. The RECs generated by the Lakeswind wind facility have been sold to the customer as part of their long-term contract.

New Hampshire (ISO-NE)

The New Hampshire market has an RPS, is part of the New England REC market and is also a partner in the Regional Greenhouse Gas Initiative - a carbon cap and trade program. The Antrim wind facility has long-term contracts in place for its energy and environmental attributes plus long-term capacity commitments. As a result, state and regional environmental and market regulations and policy will have an immaterial impact on revenues.

Pennsylvania (PJM)

Pennsylvania has an RPS and is linked to the New England REC markets. PJM's capacity market's Minimum Offer Price Rule ("MOPR") is being revised. The Big Level wind facility does not sell its RECs to entities regulated by the RPS, so is not subject to MOPR capacity market bid requirements.

Washington

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

If the state implements a carbon pricing regulation, the Transition Bill requires the state to exempt Centralia from any related costs.

Wyoming

Wyoming has no RPS or carbon-related market. No recent actions have been taken to reconsider a wind tax in the state. Wyoming wind facility has long-term contracts for its power and environmental attributes and the Corporation expects state environmental and market regulations and policy will not have a material impact on revenues.

Australia

On December 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The AU$2.55 billion ERF is the centrepiece of the Australian government's policy and provides a policy framework to cut emissions by five per cent below 2000 levels by 2020 and 26 to 28 per cent below 2005 emissions by 2030. The ERF's safeguard mechanism, commencing from July 1, 2016, is designed to ensure emissions reductions purchased by the Australian government through the ERF are not displaced by significant increases in emissions elsewhere in the economy. The ERF and its safeguard mechanism provide incentives to reduce emissions across the Australian economy.

The Australian government has also committed to develop a National Energy Productivity Plan with a target to improve Australia's energy productivity by 40 per cent between 2015 and 2030. The ERF is not expected to have a material impact on our Australian assets as a result of the Australian assets being primarily composed of gas-fired generation. In addition, on June 23, 2015, the federal Australian government also reformed the Renewable Energy Target ("RET") scheme. The RET should add at least 33,000 GWh of renewable sources by 2020. This would double the amount of large-scale renewable energy being delivered compared to current levels and result in approximately 23.5 per cent of Australia's electricity generation being sourced from renewable projects.

Under the ERF safeguard mechanism, individual facility compliance requirements for emitting plants do not take effect unless the total electricity sector emissions exceed 198 MtCO2e annually. Australia has not crossed this threshold and electricity sector emissions are trending downwards. As a result, the facilities have no carbon-related costs at this time.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but to the communities in which we operate. We expect that increased scrutiny will continue to be placed on environmental emissions and compliance. We, therefore, take a proactive approach to minimizing risks to our results. Our Board provides oversight to our environmental management programs and emission reduction initiatives in order to ensure continued compliance with environmental regulations.

Our environmental management programs include the elements summarized below:

Renewable Power

We continue to invest in and build renewable power resources. We currently have four renewable projects that are either underway or recently completed totaling approximately 470 MW. In December 2019, we brought into service two wind farms located in the US totaling 119 MW. We also signed an agreement to purchase a 49 per cent stake in another wind farm of 136.8 MW located in the State of Washington. We are presently constructing an additional 207 MW of wind generation in Alberta. We are also developing a 10 MW battery storage project in Alberta with support from Emissions Reduction Alberta. We aiming to test the technology and acquire knowledge in its application to meet customer needs. See "*General Development of the Business – Three-Year History - Generation and Business Development*".

We believe that a larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through RECs or through emission offsets. In addition, we have developed policies and procedures in order to comply with regulatory guidance and to lessen any environmental disruption caused by our renewable power resources, which includes monitoring noise and the avian impacts at our wind generation facilities.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We have installed mercury control equipment at all of our coal operations and we achieve an 80 per cent capture rate of mercury at all coal facilities. Our Keephills 3 plant uses supercritical combustion technology to maximize thermal efficiency, as well as sulphur dioxide capture and low oxides of nitrogen combustion technology. Uprate or energy efficiency projects completed at our Keephills and Sundance plants, including a 15 MW uprate finalized in 2015 at Sundance 3, have improved the energy and emissions efficiency of those units. In 2018 we commenced co-firing with gas at our merchant coal facilities in Alberta. This has resulted in a material reduction in the volume of emissions of CO_2/MWh from this fleet. In November 2019, we fully commissioned the Pioneer Pipeline significantly reducing the level of carbon emissions from our current co-fired coal units.

Offsets Portfolio

TransAlta maintains a GHG emissions offset portfolio with a variety of instruments that can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emission offset opportunities that also allow us to meet emission targets at a competitive cost. We ensure that any investments in offsets will meet certification criteria in the market in which they are to be used.

Environmental Regulations

Recent or future changes to environmental laws or regulations may materially adversely affect us. As indicated under "*Risk Factors*" in this AIF and within the "*Governance and Risk Management*" section of the Annual MD&A, many of our activities and properties are subject to environmental requirements, as well as changes in our liabilities and obligations under these requirements, which may have a material adverse effect upon our consolidated financial results, operations or performance.

RISK FACTORS

Readers should consider carefully the risk factors set forth below as well as the other information contained and incorporated by reference in this AIF. For a further discussion of risk factors affecting TransAlta, please refer to "*Governance and Risk Management*" in the Annual MD&A, which is incorporated by reference herein.

A reference herein to a material adverse effect on the Corporation means such an effect on the Corporation or its business, financial condition, results of operations, or its cash flows, as the context requires.

The operation and maintenance of our facilities involves risks that may materially and adversely affect our business.

The operation, maintenance, refurbishment, construction and expansion of power generation facilities involve risks, including breakdown or failure of equipment or processes, fuel interruption and performance below expected levels of

output or efficiency. Certain of our generation facilities, particularly in Alberta, were constructed many years ago and may require significant capital expenditures to maintain peak efficiency or to maintain operations. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities prior to occurrence or eliminate all adverse consequences in the event of failure. In addition, weather-related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of our facilities and may materially adversely affect us.

We have entered into ongoing maintenance and service agreements with the manufacturers of certain critical equipment. If a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support, we may have to enter into alternative arrangements with other providers if they cannot perform the maintenance themselves. These arrangements could be more expensive to us than our current arrangements and this increased expense could have a material adverse effect on our business. If we are unable to enter into satisfactory alternative arrangements, our inability to access technical expertise or parts could have a material adverse effect on us.

While we maintain an inventory of, or otherwise make arrangements to obtain, spare parts to replace critical equipment and maintain insurance for property damage to protect against certain operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties which could result if we were unable to operate our generation facilities at a level necessary to comply with sales contracts (including the Alberta PPAs).

We may be subject to the risk that it is necessary to operate a plant at a capacity level beyond that which we have contracted for power in order to provide steam in fulfillment of such a contract. In such circumstances, the costs to produce the steam being sold may exceed the revenues derived therefrom.

We may fail to meet financial expectations.

Our quarterly revenue, earnings, cash flows and results of operations are difficult to predict and fluctuate from quarter to quarter. Our quarterly results of operations are influenced by a number of factors, including the risks described in this AIF, many of which are outside of our control, which may cause such results to fall below market expectations. Although we base our planned operating expenses in part on our expectations of future revenue, a significant portion of our expenses are relatively fixed in the short term. If revenue for a particular quarter is lower than expected, we likely will be unable to proportionately reduce our operating expenses for that quarter, which will adversely affect our results of operations for that quarter.

Many of our activities and properties are subject to environmental requirements and changes in, or liabilities under these requirements, may materially adversely affect our business.

Our operations are subject to federal, provincial, state and local environmental laws, regulations and guidelines, relating to the generation and transmission of electrical and thermal energy and surface mining, pertaining to pollution and protection of the environment, health and safety, and governing, among other things, air emissions, water usage and discharges, storage, treatment and disposal of waste and other materials and remediation of sites and land use responsibility (collectively, "environmental regulation"). These laws can impose liability and obligations for costs to investigate and remediate contamination without regard to fault and under certain circumstances liability may be joint and several, resulting in one responsible party being held responsible for the entire obligation. Environmental regulation can also impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transport, treatment and disposal of hazardous substances and waste and can impose clean-up, disclosure or other responsibilities with respect to spills, releases and emissions of various substances to the environment. Environmental regulation can also require that facilities and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, there is an increasing level of environmental regulation regarding the use, treatment and discharge of water and we anticipate the adoption of new or additional emission regulations at a national level in Canada, the US and Australia, which may impose different compliance requirements or standards on our business. These various compliance standards may result in additional costs for our business or may impact our ability to operate our facilities.

To comply with environmental regulations, we must incur material capital and operating expenditures relating to environmental monitoring, emissions and effluent control equipment and processes; emissions measurement, verification and reporting; emissions fees; and other compliance activities or obligations. We expect to continue to have environmental expenditures in the future. Stricter standards, new or greater regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Corporation subject to environmental regulation and the implementation of provincial, state and national GHG emissions, mercury emissions or other air emissions regulation which in themselves may not be aligned and may impose varying obligations on us in the jurisdictions in which we operate and which could increase the amount of our expenditures. To the extent these expenditures cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs or otherwise, our costs could be material. In addition, compliance with environmental regulation might result in restrictions on some of our operations. If we do not comply with

environmental regulation, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on us, curtail our operations, or require significant expenditures on compliance, new equipment or technology, reporting obligations and research and development.

In addition to environmental regulation, we could also face civil liability in the event that private parties seek to impose liability on us for property damage, personal injury or other costs and losses. We cannot guarantee that lawsuits or administrative or investigative actions will not be commenced against us and otherwise affect our operations and assets. If an action is filed against us or may otherwise affect our operations and assets, we could be required to make substantial expenditures to defend against or evidence our activities or to bring our Corporation, our operations and assets into compliance, which could have a material adverse effect on our business.

A number of recent federal, provincial, state and local regulatory efforts continue to focus on potential climate change or GHG emissions regulation, and mandatory GHG reporting requirements have become effective in both Canada and the US. Mandatory GHG emissions reductions requirements are expected to impose increased costs on our business, as is expected to be the case generally for thermal power producers in North America. We are subject to other air quality regulations, including mercury regulations. To the extent new or additional GHG, mercury or other air emission regulations may require us to incur costs that cannot be passed through to our customers under its power purchase agreements, the costs could be material and have a material adverse effect on our business. In terms of TransAlta's existing gas-fired facilities, we currently have change-in-law provisions allowing flow-through of carbon tax-related costs, and we expect that any new contracts will contain similar provisions.

Our surface mining operations are subject to laws and regulations establishing mining, environmental protection and reclamation standards for all aspects of surface mining. The estimated reclamation costs applicable to the Corporation's operations may be inaccurate and could require greater financial resources than currently anticipated. As a mine owner or operator, we must obtain permits from the applicable regulatory body providing for the authorization of certain mining operations that result in a disturbance of the surface. These requirements seek to limit the adverse impacts of coal mining and more restrictive requirements may be adopted from time to time. As a mine owner or operator, we may also be required to submit a bond or otherwise secure payment of certain long-term obligations including mine closure or reclamation costs. Surety bond costs have increased in recent years while the market terms of such bonds have generally become more unfavourable. In addition, the number of companies willing to issue surety bonds has decreased. We could be required to self-fund these obligations should we be unable to renew or secure the required surety bonds for our mining operations or if it becomes more economical to do so.

We may be unsuccessful in legal actions.

We are occasionally named as a defendant in claims and legal actions and as a party in commercial disputes which are resolved by arbitration or other legal proceedings. We may also bring legal actions against third parties as part of a commercial dispute through an arbitration or other legal proceeding. There can be no assurance that we will be successful in any such claim or defence or that any claim or legal action that is decided adverse to us will not materially and adversely affect us**.** On April 23, 2019, Mangrove Partners Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice, naming TransAlta, the incumbent members of the Board of Directors of TransAlta on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is seeking to set aside the Brookfield transaction and, if successful, this could be expected to have a material adverse impact on the Corporation, including its ability to continue to return capital through share buybacks and satisfy the upcoming $400 million payable on the maturity of the medium term notes, while at the same time advancing its coal-to-gas conversion strategy and executing on other growth opportunities and strategic plans. See "*Legal Proceedings and Regulatory Actions*".

Unexpected changes in the cost of maintenance or in the cost and durability of components for the Corporation's facilities may adversely affect its results of operations.

Unexpected increases in the Corporation's cost structure that are beyond the control of the Corporation could materially adversely impact its financial performance. Examples of such costs include, but are not limited to, unexpected increases in the cost of procuring materials and services required for maintenance activities, and unexpected replacement or repair costs associated with equipment underperformance or lower-than-anticipated durability.

Equipment failure may cause us to suffer a material adverse effect.

There is a risk of equipment failure material to our operations due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on our business. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal and corrosion damage in boilers, generators and turbines, and other issues that can lead to outages and increased production risk. An extended outage could have a material adverse effect on our business, financial condition or cash flow from operations.

There can be no assurance that any applicable insurance coverage would be adequate to protect our business from material adverse effect. In addition, there can be no assurance that we will be able to restore equipment or assets that have reached the end of their useful life.

Our facilities, construction projects and operations are exposed to effects of natural disasters, public health crises and other catastrophic events beyond our control and such events could result in a material adverse effect.

Our facilities, construction projects and operations are exposed to potential interruption and damage, partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, ice storms, earthquakes and public health crises, such as pandemics and epidemics), other seismic activity, equipment failures and the like. Climate change can increase the frequency and severity of these extreme weather events. There can be no assurance that in the event of an earthquake, hurricane, tornado, tsunami, typhoon, terrorist attack, act of war or other natural, man-made or technical catastrophe, all or some parts of our generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event that disrupts the ability of our power generation assets to produce or sell power for an extended period, including events that preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on our business. Our facilities, construction projects and operations could be exposed to effects of severe weather conditions, natural and man-made disasters and potentially other catastrophic events. The occurrence of such an event may not release us from performing our obligations pursuant to PPAs or other agreements with third parties. In addition, many of our generation facilities are located in remote areas which make access for repair of damage difficult. Catastrophic events, including public health crises, could result in volatility and disruption to global supply chains, disruption to global financial markets, trade and market sentiment, risks to employee health and safety, a slowdown or temporary suspension of operations in impacted locations, postponements in the initiation and/or completion of the Corporation's development or construction projects, and delays in the completion of services, any of which may result in the Corporation incurring penalties under contracts, additional costs, or the cancellation of contracts.

Dam and dyke failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities.

A natural or man-made disaster, and certain other events, including natural or induced seismic activity, could potentially cause dam failures at our hydroelectric facilities. The occurrence of dam or dyke failures at any of our hydroelectric or coal facilities could result in a loss of generating capacity, damage to the environment or damages and harm to third parties or the public, and such failures could require us to incur significant expenditures of capital and other resources or expose us to significant liabilities for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Reinforcing all dams or dykes to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam or dyke failures could have a material adverse effect on us.

We may be adversely affected if our supply of water is materially reduced.

Hydroelectric, natural gas and coal-fired plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run-off, and other factors beyond our control, may reduce the water flow to our facilities. Any material reduction in the water flow to our facilities would limit our ability to produce and market electricity from these facilities and could have a material adverse effect on us. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in jurisdictions where we operate. Any such change in regulations could have a material adverse effect on us.

Variation in wind levels may negatively impact the amount of electricity generated at our wind facilities.

Wind is naturally variable. Therefore, the level of electricity produced from our wind facilities will also be variable. In addition, the strength and consistency of the wind resource at our wind facilities may vary from what we anticipate due to a number of factors, including the extent to which our site-specific historic wind data and wind forecasts accurately reflects actual long-term wind speeds, strength and consistency, the potential impact of climatic factors, the accuracy of our assumptions relating to, among other things, weather, icing, degradation, site access, wake and wind shear line losses and wind shear, and the potential impact of topographical variations.

A reduced amount of wind at the location of one or more of our wind facilities over an extended period may reduce the production from such facilities, as well as any environmental attributes that accrue to us related to that production and reduce our revenues and profitability.

Changes in the price of electricity and availability of fuel supplies required to generate electricity may materially adversely affect our business.

A significant portion of our revenues are tied, either directly or indirectly, to the market price for electricity in the markets in which we operate. Market electricity prices are impacted by a number of factors, including the strength of the economy, the available transmission capacity, the price of fuel that is used to generate electricity (and, accordingly, certain of the factors that affect the price of fuel described below); the management of generation and the amount of excess generating capacity relative to load in a particular market, the cost of controlling emissions of pollution, including potentially the cost of carbon, the structure of the particular market, increased adoption of energy efficiency and conservation initiatives, and weather conditions that impact electrical load. As a result, we cannot accurately predict future electricity prices and electricity price volatility could have a material adverse effect on us.

We buy natural gas and a portion of our coal to supply the fuel needed to generate electricity. We could be materially adversely affected if the cost of fuel that we must buy to generate electricity increases to a greater degree than the price that we can obtain for the electricity that we sell. Several factors affect the price of fuel, many of which are beyond our control, including:

- prevailing market prices for fuel;
- global demand for energy products;
- the cost of carbon and other environmental concerns;
- weather-related disruptions affecting the ability to deliver fuels or near-term demand for fuels;
- increases in the supply of energy products in the wholesale power markets;
- the extent of fuel transportation capacity or cost of fuel transportation service into our markets; and
- the cost of mining that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

Changes in any of these factors may increase our cost of producing power or decrease the amount of revenue received from the sale of power, which could have a material adverse effect on us.

Availability or disruption of fuel supply to our thermal plants could have an adverse impact on the operation of our facilities and our financial condition.

Our thermal facilities are reliant on having adequate natural gas and coal available to run the facilities reliably and at full capacity. As a result, we face the risk of not having adequate fuel supplies available due to insufficient natural gas transportation service, disruptions in fuel supplies due to weather, strikes, lock-outs, or breakdowns of equipment, or timing of receiving regulatory approvals. As well, the coal used to fuel the Centralia Thermal facility is sourced from the Powder River Basin in Montana and Wyoming through contracts to purchase and transport such coal to our Centralia Thermal facility. These existing coal contracts for the Centralia Thermal plant expire at the end of 2020. The loss of our suppliers or our inability to renew our existing coal contracts for Powder River Basin coal at favourable terms, or at all, could also significantly affect our ability to serve our customers and have an adverse impact on our financial condition and results of operations. We could face the risk of adequate supply service due to our reliance on the Pioneer Pipeline as a significant provider of natural gas for our Sundance and Keephills units.

Changes in general economic and market conditions may have a material adverse effect on us.

Adverse changes in general economic and market conditions and, more specifically, in the markets in which we operate, could negatively impact demand for electricity, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, or credit risk and counterparty risk, which could cause us to suffer a material adverse effect.

The market price for our common shares may be volatile.

The market price for our common shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond our control, including: (a) actual or anticipated fluctuations in our results of operations; (b) recommendations by securities research analysts; (c) changes in the economic performance or market valuations of other companies that investors deem comparable; (d) the loss or resignation of executive officers and other key personnel; (e) sales or perceived sales of additional common shares; (f) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving us or our competitors; and (g) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the power generation industry or our target markets.

Financial markets have experienced significant price and volume fluctuations in recent years that have particularly affected the market prices of equity securities of companies and such fluctuations have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of our common shares may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values which may result in impairment losses. Certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in our common shares by those institutions, which could adversely affect the trading price of our common shares.

A downgrade of our credit ratings could materially and adversely affect us.

Rating agencies regularly evaluate us, basing their ratings of our long-term and short-term debt on a number of factors. There can be no assurance that one or more of our credit ratings and the corresponding outlook will not be changed. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions with us. A credit rating downgrade could potentially impair our ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit our access to private and public credit markets and increase the costs of borrowing under our existing credit facilities. For further information on posting collateral, please see Note 15(C) of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

Our cash dividend payments are not guaranteed.

The payment of dividends is not guaranteed and could fluctuate. The Board has the discretion to determine the amount and timing of any dividends to be declared and paid to our shareholders. In addition, the payment of dividends on common shares is, in all cases, subject to prior satisfaction of preferential dividends applicable to each series of our first preferred shares. We may alter our dividend policy at any time. The Board's determination to declare dividends will depend on, among other things, results of operations; financial condition; current and expected future levels of earnings; operating cash flow; liquidity requirements; market opportunities; income taxes; maintenance and growth capital expenditures; debt repayments; legal, regulatory and contractual constraints; working capital requirements; tax laws and other relevant factors. Our short- and long-term borrowings may prohibit us from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of any dividends we may pay in the future. If we continue to pay dividends at the current level, we may not retain a sufficient amount of cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund our operations in the event of a significant business downturn. The Board, subject to the requirements of our bylaws and other governance documents, may amend, revoke or suspend our dividend policy at any time. A decline in the market price or liquidity, or both, of our common shares could result if the Board establishes large reserves that reduce the amount of quarterly dividends paid or if we reduce or eliminate the payment of dividends.

We are dependent on the operations of our facilities for our cash availability. The actual amount of cash available for dividends to holders of our common shares will depend upon numerous factors relating to each of our generation facilities including: operating performance of our generation facilities, profitability, changes in gross margin, fluctuations in working capital, capital expenditure levels, applicable laws, compliance with contracts and contractual restrictions contained in the instruments governing any indebtedness. Any reduction in the amount of cash available for distribution from our generation facilities will reduce the amount of cash available to pay dividends to holders of our common shares.

We operate in a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the United States and Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity and international conglomerates. In addition, potential customers may look to deploy their own capital to self-supply their own electricity needs. Some competitors have significantly greater financial and other resources than we do. Such competition could have a material adverse effect on our business. Emerging technology effecting the demand, generation, distribution or storage of electricity may also significantly impact our business and ability to compete.

We could suffer lost revenues or increased expenses and penalties if we are unable to operate our generation facilities at a level necessary to comply with our PPAs.

The ability of our facilities to generate the maximum amount of power which can be sold under PPAs is an important determinant of our revenues. Under certain PPAs, if the facility is not capable of generating electricity for the required availability in a given contract year, penalty payments may be payable to the relevant purchaser by us. The payment of any such penalties could adversely affect our revenues and profitability.

Our revenues may be reduced upon expiration or termination of PPAs.

We sell power under PPAs that expire at various times. In addition, these PPAs may be subject to termination in certain circumstances, including default by the facility or plant owner or operator. When a PPA expires or is terminated, it could result in us having less stable cash flows and it is possible that the price received by the relevant facility or plant for power under subsequent selling arrangements may be reduced significantly. It is also possible that to the extent a PPA is negotiated after the initial PPAs have run their course, the new contract may not be available at prices that permit the continued operation of the affected facility or plant on a profitable basis. If this occurs, the affected facility or plant may be forced to permanently cease operations.

Climate change and other variations in weather can affect demand for electricity and our ability to generate electricity.

Due to the nature of our business, our earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar farm. Variations in weather may be impacted by climate change resulting in sustained higher temperatures and rising sea levels which could have an impact on our generating assets. In Western Australia and other operating locations, temperatures could periodically exceed certain operating and safety thresholds, which could make it difficult for the Corporation to continue to generate electricity for such periods, and such circumstances could pose threats to the Corporation's equipment and personnel.

Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on wind turbine blades depends on a number of factors, including temperature, and ambient humidity. The accumulation of ice on wind turbine blades can have a significant impact on energy yields, and could result in the wind turbine experiencing more down time. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production.

In addition, climate change could result in increased variability to our water and wind resources.

The laws and regulations in the various markets in which we operate are subject to change, which may materially adversely affect us.

Most of the markets in which we operate and intend to operate are subject to significant regulatory oversight and control. We are not able to predict whether there will be any further changes in the regulatory environment, including potential carbon and other environmental regulations, changes in market structure or market design, or changes in other laws and regulations. Existing market rules, regulations and reliability standards are often dynamic and may be revised or re-interpreted and new laws and regulations may be adopted or become applicable to us or our facilities, which could have a material adverse effect on us.

We manage these risks systematically through a regulatory and compliance program designed to reduce any potential negative impact on us. However, we cannot guarantee that we will be able to adapt our business in a timely manner in response to any changes in the regulatory regimes in which we operate, and such failure to adapt could have a material adverse effect on our business.

Regulatory authorities may also from time to time audit or investigate our activities in the markets in which we operate or pursue trading. Such audits or investigations may result in sanctions or penalties which may materially affect our future activities, our reputation or our financial status.

Our facilities are also subject to various licensing and permitting requirements in the jurisdictions in which we operate. Many of these licenses and permits need to be renewed from time to time. If we are unsuccessful in obtaining or renewing such licenses or permits, or the terms of such licenses or permits are changed in a manner that is adverse to our business, we could be materially adversely affected.

Any changes in the rules and regulations of provincial or state public utility commissions or other regulatory bodies in the other markets in which we compete, or may compete in the future, may materially adversely affect us.

Changes in opinions of our Corporation from external parties may have a material adverse effect on us.

Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments and other entities. Our reputation is one of our most valued assets. The potential for harming our reputation exists in every business decision and all risks can have an impact on reputation, which in turn can negatively impact our business and securities. Reputational risk cannot be managed in isolation from other forms of risk. Negative impacts from a compromised reputation could include revenue loss, reduction in customer base, and decreased value of our securities.

We depend on certain joint venture, strategic and other partners that may have interests or objectives which conflict with our objectives and such differences could have a negative impact on us.

We have entered into various types of arrangements with communities or joint venture, strategic or other partners in connection with the operation of our facilities and assets. Certain of these partners may have or develop interests or objectives which are different from, or in conflict with, our objectives. Any such differences could have a negative impact on the Corporation's ability to realize upon the anticipated benefits of, or the anticipated increase in the value of facilities or assets subject to, these arrangements. We are sometimes required through the permitting and approval process to notify and consult with various stakeholder groups, including landowners, First Nations and municipalities. Any unforeseen delays in this process may negatively impact our ability to complete any given facility on time or at all and could result in write-offs or give rise to reputational harm.

We are dependent on access to parts and equipment from certain key suppliers and we may be adversely affected if these relationships are not maintained.

Our ability to compete and expand will be dependent on having access, at a reasonable cost, to equipment, parts and components which are technologically and economically competitive with those utilized by our competitors. Although we have individual framework agreements with various suppliers, there can be no assurance that these relationships with suppliers will be maintained. If they are not maintained, our ability to compete may be impaired due to lack of access to these sources of equipment, parts or components.

Our information technology systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyberattack and other similar disruptions, all of which could have a material adverse effect on our business.

We rely on technology, mainly on computer, telephone, satellite, cellular and related networks and infrastructure, to conduct our business and monitor the production of our generation facilities. These systems and infrastructure could be vulnerable to unforeseen problems including, but not limited to, cyberattacks, breaches, vandalism and theft. We have put in place a number of systems, processes, practices and data backups designed to protect against intentional or unintentional misappropriation or corruption of our systems and information or disruption of our operations. Despite our implementation of security measures, our information technology systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyberattack and other similar disruptions.

Any damage or failure that causes an interruption in operations could have an adverse effect on our customers. Additionally, we actively protect our generation facility infrastructure against physical damage, security breaches and service disruption from any of a variety of causes. Cyberattacks, theft, vandalism and other disruptions could jeopardize the security of information stored in and transmitted through our systems and network infrastructure, and could result in significant set-backs, potential liabilities and deter future customers. While we have systems, policies, hardware, practices, data backups, disaster recovery and procedures designed to prevent, detect or limit the effect of the failure, interruptions or security breaches of our generation facility and infrastructure, there can be no assurance that these measures will be sufficient and that such failures, interruptions or security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

Cyberattacks may cause disruptions to our operations and could have a material adverse effect on our business.

We rely on our information technology to process, transmit and store electronic information and data used for the safe operation of our assets. In today's continuously evolving cybersecurity threat landscape, any attacks or breaches of network or information systems may cause disruptions to our business operations or compromise proprietary, confidential or personal information of the Corporation, its customers, partners or others with whom the Corporation has dealings. Cyberattackers may use a range of techniques, from exploiting vulnerabilities within our user-base, to using sophisticated malicious code on a single or distributed basis to try to breach our network security controls. Attackers may also use a combination of techniques in their attempt to evade safeguards such as firewalls, intrusion prevention systems and antivirus software that exist on our network infrastructure systems. A successful cyberattack

may allow for the unauthorized interception, destruction, use or dissemination of proprietary, confidential or personal information and may cause disruptions to our operations.

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

While we have systems, policies, hardware, practices, data backups and procedures designed to prevent or limit the effect of security breaches of our network and infrastructure, there can be no assurance that these measures will be sufficient and that such security breaches will not occur or, if they do occur, that they will always be adequately addressed in a timely manner.

Our facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.

Our power generation facilities depend on electric transmission systems and related facilities owned and operated primarily by third parties to deliver the electricity that we generate to delivery points where ownership changes and we are paid. These grids operate with both regulatory and physical constraints which in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which our power generation facilities are physically disconnected from the power grid, or our production curtailed, for periods of time. Most of our electricity sales contracts do not provide for payments to be made if electricity is not delivered.

Our power generation facilities may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which our power generation facilities are connected. Our power generation facilities in the future may not be able to secure access to this interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate PPAs or to construct new projects. In addition, we may not benefit from preferential arrangements in the future. Any such increased costs and delays could delay the commercial operation dates of any new projects and negatively impact our revenues and financial condition.

Failure to close the second tranche of the Brookfield transaction, or Mangrove being successful in its claim to set aside the Brookfield transaction, could have a material adverse effect on our business.

If Mangrove is successful in its claim against the Corporation to have the Brookfield transaction set aside, and/or the second $400 million tranche of the investment by Brookfield otherwise fails to close, this could have a material adverse effect on the Corporation, including its ability to continue to return capital through share buybacks, meet certain financial obligations, continue to advance its coal-to-gas conversion strategy and execute on other growth opportunities and strategic plans. The Corporation would likely need to raise additional cash or working capital through the public or private sale of debt or equity securities, sale of assets, funding from joint-venture or strategic partners, debt financing or short-term loans, and the terms of such transactions may be unduly expensive or burdensome to the Corporation relative to the terms of the Brookfield investment and disadvantageous to our existing shareholders. There can be no assurance that the Corporation would be successful in securing alternative sources of capital.

Trading risks may have a material adverse effect on our business.

Our trading and marketing business frequently involves the establishment of trading positions in the wholesale energy markets on both a medium-term and short-term basis, on both an asset and proprietary basis. To the extent that we have long positions in the energy markets, a downturn in market prices will result in losses from a decline in the value of such long positions. Conversely, to the extent that we enter into forward sales contracts to deliver energy that we do not own, or take short positions in the energy markets, an upturn in market prices will expose us to losses as we attempt to cover any short positions by acquiring energy in a rising market.

In addition, from time to time, we may have a trading strategy consisting of simultaneously holding a long position and a short position, from which we expect to earn a profit based on changes in the relative value of the two positions. If, however, the relative value of the two positions changes in a direction or manner that we did not anticipate, we would realize losses from such a paired position.

If the strategy that we use to hedge our exposures to these various risks is not effective, we could incur significant losses. Our trading positions can be impacted by volatility in the energy markets that, in turn, depend on various factors,

including weather in various geographical areas and short-term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect our positions, which could also have a material adverse effect on our business.

We use a number of risk management controls conducted by our independent Risk Management group in order to limit our exposure to risks arising from our trading activities. These controls include risk capital limits, VaR, GMaR, tail risk scenarios, position limits, concentration limits, credit limits, and approved product controls. We cannot guarantee that losses will not occur and such losses may be outside the parameters of our risk controls.

Because of our multinational operations, we are subject to currency rate risk and regulatory and political risk.

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the cash flows from those operations, the acquisition of equipment and services from foreign suppliers, and our US dollar denominated debt. Our exposures are primarily to the US and Australian currencies. Changes in the values of these currencies relative to the Canadian dollar could negatively impact our operating cash flows or the value of our foreign investments. While we attempt to manage this risk through the use of hedging instruments, including cross-currency interest rate swaps, forward exchange contracts and matching revenues and expenses by currency at the Corporate level, there can be no assurance that these risk management efforts will be effective, and fluctuations in these exchange rates may have a material adverse effect on our business.

In addition to currency rate risk, our foreign operations may be subject to regulatory and political risk. Any change to the regulations governing power generation or the political climate in the countries where we have operations could impose additional costs and have a material adverse effect on us.

Risks relating to TransAlta's development and growth projects and acquisitions may materially and adversely affect us.

Development and growth projects and acquisitions that we undertake may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third-party opposition, cost escalations, construction delays, shortages of raw materials or skilled labour and capital constraints. The occurrences of these risks could have a material and adverse impact on us, our financial condition, results of operations and cash flows.

Expansion of our business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development projects could have a material adverse impact on us, our financial condition, results of operations and cash flows. Further, we cannot make assurances that we will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

We may pursue acquisitions in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to us currently, which may adversely affect our ability to receive revenues or enforce our rights in connection with any such foreign operations. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the projects that we may acquire, thus limiting our ability to control the operation of such projects. Any existing or new operations may also be subject to significant political, economic and financial risks, which vary by country, and may include: (a) changes in government policies or personnel; (b) changes in general economic conditions; (c) restrictions on currency transfer or convertibility; (d) changes in labour relations; (e) political instability and civil unrest; (f) regulatory or other changes in the local electricity market; and (g) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

With respect to acquisitions, we cannot make assurances that we will identify suitable transactions or that we will have access to sufficient resources, through our credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition that we propose or complete would be subject to normal commercial risks that the transaction may not be completed on the terms negotiated, on time, or at all. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on our business, financial condition, results of operations and cash flows.

We may have difficulty raising needed capital in the future, which could significantly harm our business.

To the extent that our sources of cash and cash flow from operations are insufficient to fund our activities, we may need to raise additional funds. Additional financing may not be available when needed, and if such financing is available, it may not be available on terms that are favourable to our business.

Recovery of the capital investment in power projects generally occurs over a long period of time. As a result, we must obtain funds from equity or debt financings, including tax equity transactions, or from government grants, to help finance the acquisition of projects and to help pay the general and administrative costs of operating our business. Our ability to arrange financing, either at the corporate level or at the subsidiary level (including non-recourse project debt), and the costs of such capital are dependent on numerous factors, including: (a) general economic and capital market conditions; (b) credit availability from banks and other financial institutions; (c) investor confidence and the markets in which we conduct operations; (d) our financial performance; (e) our level of indebtedness and compliance with covenants in our debt agreements; and (f) our cash flow.

An increase in interest rates or a reduction in the availability of project debt financing could reduce the number of projects that we are able to finance. If we are unable to raise additional funds when needed, we could be required to delay acquisition and construction of growth projects (including the coal-to-gas conversions), reduce the scope of projects, abandon or sell some or all of our projects or generation facilities, or default on our contractual commitments in the future, any of which could adversely affect our business, financial condition and results of operations.

TransAlta Corporation's debt securities will be structurally subordinated to any debt of our subsidiaries that are currently outstanding or may be incurred in the future.

We operate our business through, and a majority of our assets are held by, our subsidiaries, including partnerships. Our results of operations and ability to service indebtedness are dependent upon the results of operations of our subsidiaries, including TransAlta Renewables, and the payment of funds by these subsidiaries to TransAlta in the form of loans, dividends or otherwise. Our subsidiaries will not have an obligation to pay amounts due, or make any funds available for payment of, debt securities issued by TransAlta, whether by dividends, interests, loans, advances or other payments. In addition, the payment of dividends and the making of loans, advances and other payments to us by our subsidiaries may be subject to statutory or contractual restrictions.

In the event of the liquidation of any subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used to pay TransAlta's indebtedness, including any debt securities issued by TransAlta. Such indebtedness and any other future indebtedness of such subsidiaries would be structurally senior for such subsidiary to any debt securities issued by TransAlta.

Our subsidiaries have financed some investments using non-recourse project financing. Each non-recourse project loan is structured to be repaid out of cash flow provided by the investment. In the event of a default under a financing agreement which is not cured, the lenders would generally have rights to the related assets. In the event of foreclosure after a default, our subsidiary may lose its equity in the asset or may not be entitled to any cash that the asset may generate. Although a default under a project loan will not cause a default with respect to any debt securities issued by TransAlta, it may materially affect our ability to service our outstanding indebtedness.

Changes in statutory or contractual restrictions may have an adverse effect on our ability to service debt obligations.

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries, including TransAlta Renewables, and the payment of funds by our subsidiaries in the form of distributions, loans, dividends, or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

The power generation industry has certain inherent risks related to worker health and safety and the environment that could cause us to suffer unanticipated expenditures or to incur fines, penalties or other consequences material to its business and operations.

The ownership and operation of our power generation assets carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government-imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licenses, permits and other approvals, and potential civil liability. Compliance with (and any future changes to) health, safety and environmental laws and the requirements of licenses, permits and other approvals

are expected to remain material to our business. The occurrence of any of these events or any changes, additions to, or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on our operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to our business and operations.

Certain of the contracts to which we are a party require that we provide collateral against our obligations.

We are exposed to risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of hedging and proprietary trading. The terms and conditions of these contracts require us to provide collateral when the fair value of these contracts is in excess of any credit limits granted by our counterparties and the contract obliges that we provide the collateral. The change in fair value of these contracts occurs due to changes in commodity prices. These contracts include: (a) purchase agreements, when forward commodity prices are less than contracted prices; and (b) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and, accordingly, increase the amount of collateral that we may have to provide, which could materially adversely affect us.

If counterparties to our contracts are unable to meet their obligations, we may be materially and adversely affected.

If purchasers of our electricity and steam or other contractual counterparties default on their obligations, we may be materially and adversely affected. While we have procedures and controls in place to manage our counterparty credit risk prior to entering into contracts, all contracts inherently contain default risk. Moreover, while we seek to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, we cannot guarantee that a party will not default. If counterparties to our contracts are unable to meet their obligations, we could suffer a reduction in revenue which could have a material adverse effect on our business.

We are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our business is exposed to the risks inherent in the construction and operation of electricity generation facilities, such as breakdowns, manufacturing defects, natural disasters, injury, damage to third parties, theft, terrorist attacks and sabotage. We are also exposed to environmental risks. We maintain insurance policies, covering usual and customary risks associated with our business, with creditworthy insurance carriers. Our insurance policies, however, do not cover losses as a result of force majeure, natural disasters, terrorist or cyberattacks or sabotage, among other things. In addition, we generally do not maintain insurance for certain environmental risks, such as environmental contamination. Our insurance policies are subject to annual review by the respective insurers and may not be renewed at all or on similar or favourable terms. A significant uninsured loss or a loss significantly exceeding the limits of our insurance policies or the failure to renew such insurance policies on similar or favourable terms could have a material adverse effect on our business, financial condition and results of operations.

Our insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for any loss or damage to any of our generation facilities may not be sufficient to permit us to continue to make payments on our debt.

Provision for income taxes may not be sufficient.

Our operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. In addition, our tax filings are subject to audit by taxation authorities. While we believe that our tax filings have been made in material compliance with all applicable tax interpretations, regulations, and legislation, we cannot guarantee that we will not have disagreements with taxation authorities with respect to our tax filings that could have a material adverse effect on our business.

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

We are subject to uncertainties regarding when we will become cash taxable.

Our anticipated cash tax horizon is subject to risks, uncertainties and other factors that could cause the cash tax horizon to occur sooner than currently projected. In particular, our anticipated cash tax horizon is subject to risks pertaining to changes in our operations, asset base, corporate structure or changes to tax legislation, regulations or interpretations. In the event we become cash taxable sooner than projected, our cash available for distribution and our dividend could decrease, which could in turn have a material adverse impact on the value of our shares.

If we fail to attract and retain key personnel, we could be materially adversely affected.

The loss of any of our key personnel or our inability to attract, train, retain and motivate additional qualified management and other personnel could have a material adverse effect on our business. Competition for these personnel is intense and there can be no assurance that we will be successful in this regard.

If we are unable to successfully negotiate new collective bargaining agreements with our unionized workforce, as required from time to time, we will be adversely affected.

While we believe we have a satisfactory relationship with our unionized employees, we cannot guarantee that we will e able to successfully negotiate or renegotiate our collective bargaining agreements on terms agreeable to TransAlta. We successfully renegotiated four collective bargaining agreements, involving 475 of our employees in 2019. In 2020, we will renegotiate six collective bargaining agreements, involving 270 employees. There is one collective agreement, covering eight employees, scheduled for renegotiation in 2021. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

EMPLOYEES

The Corporation is required to develop and retain a skilled workforce for its operations. Many of the employees of the Corporation possess specialized skills and training and the Corporation must compete in the marketplace for these workers. As at December 31, 2019, we had 1,543 active employees, which includes full-time, part-time and temporary employees, of which 573 were employed in our Canadian Coal segment (including our SunHills mining operation), 197 were employed in our US Coal segment, 198 were employed in our Gas segment, 84 were employed in our Wind and Solar business, 81 were employed in our Hydro business, 73 were employed in our Energy Marketing business and the remaining 337 employees were employed in our Corporate segment. Approximately 45 per cent of our employees are represented by labour unions. We are currently a party to 12 different collective bargaining agreements. In 2019, we renegotiated four collective bargaining agreements and we expect to renegotiate six in 2020.

CAPITAL AND LOAN STRUCTURE

Our authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. As at March 3, 2020, there were 277,075,741 common shares outstanding and 10,175,380 Series A Shares, 1,824,620 Series B Shares, 11,000,000 Series C Shares, 9,000,000 Series E Shares and 6,600,000 Series G Shares outstanding. The Corporation does not have any escrowed securities.

Common Shares

Each common share of TransAlta Corporation entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Corporation, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of our assets upon a liquidation, dissolution or winding up and subject to prior rights and privileges attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

Normal Course Issuer Bid

On May 27, 2019, the TSX accepted our notice filed to implement an NCIB for a portion of its common shares. The Board has authorized repurchases of up to a maximum of 14,000,000 common shares, representing approximately five per cent of TransAlta's public float. Purchases under the NCIB are expected to be made through open market transactions on the TSX and any alternative Canadian trading platforms, 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 May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) 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.

In connection with the investment by Brookfield, the Corporation has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the investment (which occurred on May 1, 2019).

During the year ended December 31, 2019, the Corporation purchased and cancelled 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million. For further information please see Note 26 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

First Preferred Shares

We are authorized to issue an unlimited number of first preferred shares, issuable in series and, with respect to each series, the Board is authorized to fix the number of shares comprising the series and determine the designation, rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

The first preferred shares of all series rank senior to all other shares of TransAlta Corporation with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board at the rate established by the Board at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of TransAlta Corporation unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of TransAlta Corporation until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares to the date of such liquidation, dissolution, winding up or reduction of stated capital, as applicable. After payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of our assets.

The Board may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon our failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25.00 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of TransAlta if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Subject to the share conditions attaching to any particular series providing to the contrary, we may redeem the first preferred shares of a series, in whole or from time to time in part, at the redemption price applicable to each series and we have the right to acquire any of the first preferred shares of one or more series by purchase for cancellation in the open market or by invitation for tenders at a price not to exceed the redemption price applicable to the series.

Series A Shares

12.0 million Series A Shares were issued on December 10, 2010, with a coupon of 4.60 per cent, for gross proceeds of $300 million. On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares. Certain provisions of the Series A Shares are discussed below.

Dividends on Series A Shares

The holders of Series A Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series A Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares and the Series B Shares described below, and will remain unchanged over the life of the Series A Shares.

Redemption of Series A Shares

The Series A Shares are redeemable by TransAlta, at its option, in whole or in part, on March 31, 2016, and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series A Shares of the redemption of all of the Series A Shares, the right of a holder of Series A Shares to convert such Series A Shares shall terminate and we shall not be required to give notice to the registered holders of the Series A Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series A Shares.

Conversion of Series A Shares into Series B Shares

The holders of the Series A Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series B of TransAlta (the "Series B Shares"), subject to certain conditions, on March 31, 2016 and on March 31 in every fifth year thereafter. The holders of the Series B Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate (the "T-Bill Rate") (which means, the average yield expressed as an annual rate on the 90-day Government of Canada treasury bill, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable Floating Rate Calculation Date) on the applicable date and 2.03 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 2.03 per cent.

The Series A Shares and Series B Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series A Shares and Series B Shares are identical in all material respects.

On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares on a one-for-one basis.

Voting Rights

The holders of the Series A Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series A Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series A Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series A Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation

Modification

The provisions attaching to the Series A Shares as a class may be amended with the written approval of all the holders of Series A Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series B Shares

1,824,620 Series B Shares were issued on March 31, 2016. Certain provisions of the Series B Shares are discussed below.

Dividends on Series B Shares

The holders of Series B Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, floating rate cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after conversion, the holders of Series B Shares shall be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate (the "T-Bill Rate") (which means, the average yield expressed as an annual rate on the 90-day Government of Canada treasury bill, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable Floating Rate Calculation Date) on the applicable date and 2.03 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares described above and the Series B Shares and will remain unchanged over the life of the Series B Shares.

Redemption of Series B Shares

The Series B Shares are redeemable by TransAlta, at its option, in whole or in part, on March 31, 2021, and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series B Shares of the redemption of all of the Series B Shares, the right of a holder of Series B Shares to convert such Series B Shares shall terminate and we shall not be required to give notice to the registered holders of the Series B Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series B Shares.

Conversion of Series B Shares into Series A Shares

The holders of the Series B Shares have the right to convert all or any of their shares into cumulative redeemable fixed rate first preferred shares, Series A of TransAlta (the "Series A Shares"), subject to certain conditions, on March 31, 2021, and on March 31 in every fifth year thereafter. The holders of the Series A Shares will be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends payable on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent.

The Series A Shares and Series B Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series A Shares and Series B Shares are identical in all material respects.

Voting Rights

The holders of the Series B Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series B Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series B Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series B Share held on all matters in respect of which

shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation

Modification

The provisions attaching to the Series B Shares as a class may be amended with the written approval of all the holders of Series B Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series C Shares

11.0 million cumulative redeemable rate reset first preferred shares, Series C (the "Series C Shares") were issued on November 30, 2011, with a coupon of 4.60 per cent, for gross proceeds of $275 million. Certain provisions of the Series C Shares are discussed below.

Dividends on Series C Shares

The holders of Series C Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series C Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five-year bond) on the Fixed Rate Calculation Date plus a spread of 3.10 per cent. This spread will apply to both the Series C Shares and the Series D Shares described below, and will remain unchanged over the life of the Series C Shares.

Redemption of Series C Shares

The Series C Shares were redeemable by TransAlta, at its option, in whole or in part, on June 30, 2017, and will be redeemable on June 30 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold). On June 30, 2017, none of the Series C Shares were redeemed.

If we give notice to the holders of the Series C Shares of the redemption of all of the Series C Shares, the right of a holder of Series C Shares to convert such Series C Shares shall terminate and we shall not be required to give notice to the registered holders of the Series C Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series C Shares.

Conversion of Series C Shares into Series D Shares

The holders of the Series C Shares had the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series D of TransAlta (the "Series D Shares"), subject to certain conditions, on June 30, 2017, and will again have the right to convert on June 30 in every fifth year thereafter. The holders of the Series D Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.10 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.10 per cent.

The Series C Shares and Series D Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series C Shares and Series D Shares are identical in all material respects.

On June 15, 2017, 827,628 Series C Shares were tendered for conversion into Series D Shares which is less than the one million shares required to give effect to conversions into Series D Shares. As a result, none of the Series C Shares were converted into Series D Shares on June 30, 2017.

Voting Rights

The holders of the Series C Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series C Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series C Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series C Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series C Shares as a class may be amended with the written approval of all the holders of Series C Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series E Shares

9.0 million cumulative redeemable rate reset first preferred shares, Series E (the "Series E Shares") were issued on August 10, 2012 for gross proceeds of $225 million. Certain provisions of the Series E Shares are discussed below.

Dividends on Series E Shares

The holders of Series E Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September, and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series E Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta Corporation on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five-year bond) on the Fixed Rate Calculation Date plus a spread of 3.65 per cent. This spread will apply to both the Series E Shares and the Series F Shares described below, and will remain unchanged over the life of the Series E Shares.

Redemption of Series E Shares

The Series E Shares were redeemable by TransAlta Corporation, at its option, in whole or in part, on September 30, 2017, and will be redeemable on September 30 in every fifth year thereafter by the payment of an amount of $25.00 in cash for each share to be redeemed plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold). On September 30, 2017, none of the Class E Shares were redeemed.

If we give notice to the holders of the Series E Shares of the redemption of all of the Series E Shares, the right of a holder of Series E Shares to convert such Series E Shares shall terminate and we shall not be required to give notice to the registered holders of the Series E Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series E Shares.

Conversion of Series E Shares into Series F Shares

The holders of the Series E Shares had the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series F of TransAlta (the "Series F Shares"), subject to certain conditions, on September 30,

2017, and will again have the right to convert on September 30 in every fifth year thereafter. The holders of the Series F Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.65 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.65 per cent.

The Series E Shares and Series F Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series E Shares and Series F Shares are identical in all material respects.

On September 15, 2017, 133,969 Series E Shares were tendered for conversion into Series F Shares which is less than the one million shares required to give effect to conversions into Series F Shares. As a result, none of the Series E Shares were converted into Series F Shares on September 30, 2017.

Voting Rights

The holders of the Series E Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series E Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series E Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series E Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series E Shares as a class may be amended with the written approval of all the holders of Series E Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series G Shares

6.6 million cumulative redeemable rate reset first preferred shares, Series G (the "Series G Shares") were issued on August 15, 2014, for gross proceeds of $165 million. Certain provisions of the Series G Shares are discussed below.

Dividends on Series G Shares

The holders of Series G Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series G Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta Corporation on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 3.80 per cent. This spread will apply to both the Series G Shares and the Series H Shares described below, and will remain unchanged over the life of the Series G Shares.

Redemption of Series G Shares

The Series G Shares are redeemable by TransAlta Corporation, at its option, in whole or in part, on September 30, 2019, and on September 30 in every fifth year thereafter by the payment of an amount of $25.00 in cash for each share to be redeemed plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series G Shares of the redemption of all of the Series G Shares, the right of a holder of Series G Shares to convert such Series G Shares shall terminate and we shall not be required to give notice to the registered holders of the Series G Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series G Shares.

Conversion of Series G Shares into Series H Shares

The holders of the Series G Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series H of TransAlta (the "Series H Shares"), subject to certain conditions, on September 30, 2019, and on September 30 in every fifth year thereafter. The holders of the Series H Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest (expressed as a percentage and rounded to the nearest one hundred thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.80 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.80 per cent.

The Series G Shares and Series H Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series G Shares and Series H Shares are identical in all material respects.

On September 17, 2019, 140,730 Series G Shares were tendered for conversion into Series H Shares which is less than the one million shares required to give effect to conversions into Series H Shares. As a result, none of the Series G Shares were converted into Series H Shares on September 30, 2019.

Voting Rights

The holders of Series G Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series G Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series G Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series G Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series G Shares as a class may be amended with the written approval of all the holders of Series G Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Related Party Articles Provisions

The articles of the Corporation contain provisions restricting the ability of the Corporation to enter into a "Specified Transaction" with a "Major Shareholder". A Specified Transaction requires the approval of a majority of the votes cast by holders of voting shares of the Corporation, as well as the approval of a majority of the votes cast by holders of such voting shares, excluding any Major Shareholder. A Major Shareholder generally means the beneficial owner of more than 20% of the outstanding voting shares of the Corporation. The articles contain a broad definition of beneficial ownership, and in particular, a person is considered to beneficially own shares owned by its associates and affiliates, as those terms are defined in the articles. Transactions which are considered to be Specified Transactions include the following: a merger or amalgamation of the Corporation with a Major Shareholder; the furnishing of financial assistance

by the Corporation to a Major Shareholder; certain sales of assets or provision of services by the Corporation to a Major Shareholder or vice versa; certain issuances of securities by the Corporation which increase the proportionate voting interest of a Major Shareholder; a reorganization or recapitalization of the Corporation which increases the proportionate voting interest of a Major Shareholder; and the creation of a class or series of non-voting shares of the Corporation which has a residual right to participate in earnings of the Corporation and assets of the Corporation upon dissolution or winding up.

Shareholder Rights Plan

The Corporation implemented a shareholder rights plan (the "Rights Plan") pursuant to a Shareholder Rights Plan Agreement (the "*Rights Plan Agreement*") dated as of October 13, 1992, as amended and restated as of April 26, 2019, between the Corporation and AST Trust Company (Canada) (the successor to CST Trust Company). The Shareholder Rights Plan was last confirmed at our annual and special meeting of shareholders on April 26, 2019, and will expire at the close of business on the date of our 2022 annual meeting of shareholders, unless ratified and extended by a further vote of the shareholders. The Rights Plan Agreement was assigned by AST Trust Company (Canada) to Computershare Trust Company of Canada effective November 22, 2019. For further particulars, reference should be made to the Rights Plan Agreement, as amended and restated. A copy of the Rights Plan Agreement may be obtained by contacting the Corporate Secretary, TransAlta Corporation, 110 - 12th Avenue S.W., Calgary, Alberta T2R 0G7; telephone: (403) 267-7110; or by email: corporate_secretary@transalta.com. A copy of the Rights Plan Agreement is also available electronically on SEDAR under our profile, which can be accessed at www.sedar.com, and on the SEC's EDGAR system at www.sec.gov.

Credit Facilities

In 2019, we renewed our syndicated credit agreement giving us access to a $1.25 billion committed credit facility. The agreement is fully committed for four years, expiring in 2023. The credit facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. This credit facility has been made available for general corporate purposes including financing ongoing working capital requirements, providing financing for construction capital, growth opportunities and for the repayment of outstanding borrowings.

On July 24, 2017, TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The credit agreement is fully committed for four years, and in the second quarter of 2019 was amended from $500 million to $700 million and extended to 2023. The credit facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. For further information please see Note 23 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

Long-Term Debt

The long-term debt of the Corporation consists of $651 million face value of debentures outstanding, which bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030. In addition, we have US$700 million face value in senior notes outstanding that bear interest at fixed rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040. For further information please see Note 23 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see *"Documents Incorporated by Reference"* in this AIF.

Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into a definitive investment agreement dated as of March 22, 2019 (the “Investment Agreement”) whereby Brookfield agreed to invest $750 million in the Corporation through the purchase of exchangeable securities (the "Exchangeable Securities"), which are exchangeable into an equity ownership interest in TransAlta’s Alberta Hydro Assets in the future at a value based on a multiple of the Hydro Assets’ future adjusted EBITDA (the "Option to Exchange"). The Exchangeable Securities will be issued in two tranches, with the first having occurred on May 1, 2019 consisting of $350 million of 7% unsecured subordinated debentures due May 1, 2039 and the second consisting of $400 million of a new series of redeemable, retractable first preferred shares to be issued at a second closing in October 2020. The Investment Agreement, together with an Exchange and Option Agreement (the "E&O Agreement") entered into by the parties concurrently with the closing of the first tranche of the investment, gives Brookfield the Option to Exchange all of the outstanding exchangeable securities into up to a maximum 49% equity ownership interest in TransAlta’s Alberta Hydro Assets after December 31, 2024. The Investment Agreement and the E&O Agreement also give TransAlta the right to redeem the Exchangeable Securities at any time after December 31, 2028, subject to certain terms and conditions, if Brookfield chooses not to exercise its Option to Exchange. See "*—Investment Agreement and E&O Agreement*" below.

Investment Agreement and E&O Agreement

The following description of certain provisions of the Investment Agreement and the E&O is a summary only, is not comprehensive and is qualified in its entirety by reference to the full text of each of the Investment Agreement and E&O Agreement, copies of which can be found on SEDAR under our profile at www.sedar.com and on EDGAR undere our profile at www.sec.gov.

In connection with the Investment Agreement, Brookfield has committed to purchase common shares of the Corporation on the open market over a period of 24 months following the Initial Funding Date, being May 1, 2019, to its total share ownership to not less than 9%, subject to certain exceptions and provided that the Brookfield is not obliged to purchase Common Shares at a price greater than $10 per share. This increase in shareholdings further aligns the interests of Brookfield and TransAlta. Pursuant to the Investment Agreement, the Corporation included two nominees of Brookfield on its slate of directors for election at the Corporation's 2019 annual and special meeting of shareholders.

The Investment Agreement contains certain lock-up provisions that restrict Brookfield or its affiliates' ability to transfer their TransAlta common shares during a period that commenced on May 1, 2019 and terminates on December 31, 2023 (the "Lock-Up"). The Lock-Up contains customary exceptions, including an exception for transfers of common shares by investment funds managed by or affiliated with Brookfield undertaken in accordance with the investment funds' fund requirements.

The Investment Agreement contemplates that the Exchangeable Securities will be a long-term investment and therefore may not be transferred except by Brookfield to one of its affiliates. Brookfield has agreed to be the sole representative of all of its permitted transferees for the purpose of the Investment Agreement.

The Investment Agreement includes certain standstill commitments by the Brookfield (the "Standstill"), with customary exceptions, which will be in effect for three years starting from May 1, 2019 (the "Standstill Period"). Among other things, the Standstill prohibits the Brookfield from acquiring an ownership interest in the Corporation above 19.9% of the common shares. During the Standstill Period, Brookfield has also agreed that it will: (i) vote in favour of each director nominated by the Board; (ii) vote against any shareholder nomination for directors that is not approved by the Board; (iii) vote against any proposal or resolution to remove any Board member; and (iv) vote in accordance with any recommendations by the Board on all other proposals. Certain Standstill provisions extend beyond the Standstill Period so long as Brookfield has nominees on the Board.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation, and maximizing the value, of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual hydro fee of $1.5 million for six years commencing on May 1, 2019.

Registration Rights Agreement

The following description of certain provisions of the registration rights agreement entered into between Eagle Hydro II (an affiliate of Brookfield) and the Corporation on May 1, 2019 (the "Registration Rights Agreement") is a summary only, is not comprehensive and is qualified in its entirety by reference to the full text of the Registration Rights Agreement, a copy of which can be found on SEDAR under our profile at www.sedar.com.

The Registration Rights Agreement provides that Eagle Hydro II and any affiliate of Brookfield that becomes party to the Registration Rights Agreement (each a "Holder") may, at any time and from time to time, make a written request (a "*Demand Registration*") to the Corporation to file a Prospectus Supplement with the securities commissions or similar authorities in each of the provinces of Canada in respect of the distribution of all or part of the Common Shares then held by the Holder ("*Registrable Securities*"), subject to certain restrictions set forth in the Registration Rights Agreement. Upon receipt by the Corporation of a Demand Registration, the Corporation will promptly file a Prospectus Supplement in order to permit the offer and sale or other disposition or distribution in Canada of all or any portion of the Registrable Securities held, directly or indirectly, by the Holder (a "Demand Offering"). The Corporation will not be obligated to effect: (i) more than three Demand Offerings in total during the term of the Registration Rights Agreement; or (ii) a Demand Offering if the Registrable Securities have an aggregate market price of less than $50 million.

If at any time the Corporation proposes to file a prospectus supplement with respect to the distribution of any TransAlta common shares to the public, then the Corporation will give notice of the proposed distribution to each Holder not less than five business days in advance of the anticipated filing date of the prospectus supplement (or, in the case of a "bought deal" or another public offering which is not expected to include a road show, such notice as is practicable under the circumstances), which notice will offer each Holder the opportunity to qualify for distribution such number of Registrable Securities as such Holder may request. The Corporation will use commercially reasonable efforts to include in such Prospectus Supplement such Registrable Securities (a "Piggy Back Offering"), unless the Corporation's managing underwriter or underwriters determines, in good faith, that including such Registrable Securities in the distribution

would, in their opinion, adversely affect the Corporation's distribution or sales price of the securities being offered by the Corporation.

The Demand Offerings and Piggy Back Offerings are subject to various conditions and limitations. The Corporation is entitled to defer any Demand Offering in certain circumstances, including during a regular annual and quarterly blackout period in respect of the release of its financial results.

The Registration Rights Agreement includes provisions providing for each of the Corporation and the Holders to indemnify each other for losses or claims caused by the applicable party's inclusion of a misrepresentation in disclosure included in any prospectus and for breaches of applicable securities laws.

In the case of a prospectus supplement filed in connection with a Demand Offering or Piggy Back Offering, the Corporation will pay all applicable fees and expenses incident to the Corporation's performance of, or compliance with, the terms of such offering, provided that in the event any Registrable Securities are freely tradeable at the time that the Corporation receives the offering request, the Corporation and the Holders will be jointly and severally responsible for the proportionate share of registration fees and expenses of any Holders based on the total offering price of the freely tradeable securities sold by the Holders to the total offering price of all the Securities sold by the Corporation in such offering. The Corporation and the Holders will be jointly and severally responsible for paying all selling expenses (including fees or commissions payable to an underwriter, investment banker, manager or agent and any transfer taxes attributable to the sale of Registrable Securities) with respect to Registrable Securities sold by the Holders and the Corporation will pay all selling expenses with respect to any Securities sold for the account of the Corporation. The Corporation and the Holders will be solely responsible on a joint and several basis for all out-of-pocket expenses incurred by any Holders in connection with a Demand Offering or Piggy Back Offering.

If a Holder ceases to be affiliated with the Corporation, the Holder will cease to have any rights or obligations under the Registration Rights Agreement. The Registration Rights Agreement will terminate when Brookfield together with its affiliates beneficially own in the aggregate less than 3% of the issued and outstanding common shares.

Additional details about the Brookfield investment can be found in our material change report dated March 26, 2019 available electronically on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. Copies of the Investment Agreement, together with copies of the exchangeable debenture, the E&O Agreement and the Registration Rights Agreement are also available on SEDAR and on EDGAR. Shareholders are urged to read these documents in their entirety.

Non-Recourse Debt

The Corporation has non-recourse debt outstanding in an amount equal to approximately $1,157 million face value, which is represented by bonds and debentures that bear interest at rates ranging from 2.95 per cent to 6.02 per cent and have maturity dates ranging from 2028 to 2032. For further information please see Note 23 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

Tax Equity

During the third quarter of 2019, subsidiaries of TransAlta entered into final agreements with an external party for a planned tax equity investment in the Big Level and Antrim wind projects. In December 2019, coinciding with each site achieving commercial operation, TransAlta received funding of approximately US$41 million and US$85 million, respectively.

The Corporation also assumed US$24 million in tax equity financing as part of the acquisition of the Lakeswind wind facility in 2015. Under IFRS tax equity financings are included as debt in our consolidated financial statements. For further information on tax equity please see Note 23 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

Restrictions on Debt

The syndicated credit facilities include a number of customary covenants and restrictions in order to maintain access to the funding commitments. Non-recourse bonds 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.

CREDIT RATINGS

Credit ratings provide information relating to our financing costs, liquidity and operations and affect our ability to obtain short-term and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows our commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to our financial results and provides us with better access to capital markets through commodity and credit cycles. We remain focused on strengthening our financial position and cash flow coverage ratios to ensure a strong balance sheet is maintained and sufficient financial capital is available. Our credit ratings as of December 31, 2019 are as follows:

	DBRS	Fitch	Moody's	S&P
Issuer Rating	BBB (low)	BB+	Not Applicable	BB+
Corporate Family Rating	Not Applicable	Not Applicable	Ba1	Not Applicable
Preferred Shares	Pfd-3 (low)[(1)]	Not Applicable	Not Applicable	P-4(High)
Unsecured Debt/MTNs	BBB (low)	BB+	Ba1/LGD4	BB+
Rating Outlook	Stable	Stable	Stable	Stable

Note:

(1) The outstanding Preferred Shares all have the same rating.

In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised its rating outlook to stable from positive. During 2019, DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; Standard and Poor's lowered the Corporation's Unsecured Debt rating and Issuer Rating to BB+ with a stable outlook; and Fitch Ratings lowered our Unsecured Debt rating and Issuer Rating to BB+ with a stable outlook. In Q4 2019, we decided not to renew our rating services with Fitch and the active rating from Fitch expired on January 31, 2020.

DBRS

DBRS Corporate rating analysis begins with an evaluation of the fundamental creditworthiness of the issuer, which is reflected in an "issuer rating". Issuer ratings address the overall credit strength of the issuer. Unlike ratings on individual securities or classes of securities, issuer ratings are based on the entity itself and do not include consideration for security or ranking. Ratings that apply to actual securities (secured or unsecured) may be higher, lower or equal to the issuer rating for a given entity. As of December 31, 2019, our issuer rating was BBB (low) (stable) from DBRS. A BBB rating is the fourth highest out of ten categories.

The DBRS preferred share rating scale is used in the Canadian securities market and is meant to give an indication of the risk that a borrower will not fulfill its full obligations in a timely manner, with respect to both dividend and principal commitments. Every DBRS rating is based on quantitative and qualitative considerations relevant to the borrowing entity. Each rating category is denoted by the subcategories "high" and "low". The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Each of the Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares have been rated Pfd-3 (low) (stable) by DBRS. The Pfd-3 rating is the third highest out of six categories.

The DBRS long-term rating scale provides an opinion on the risk of default, which is the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)". The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. Debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. As of December 31, 2019, our senior unsecured long-term debt is rated BBB (low) (stable) by DBRS. The BBB rating category is the fourth highest of ten categories for long term obligations.

Fitch

As of December 31, 2019, our Fitch long term Issuer Default Rating (IDR) and senior unsecured rating was BB+ with a stable outlook. The Fitch rating system describes a BB rating as speculative. BB ratings indicate that there is an elevated vulnerability to default risk, particularly when faced with uncertainties or challenges in the business or economic environment over time. However, business and/or financial flexibility exists that supports the servicing of financial commitments. The modifiers + or - may be appended to a rating to denote relative status within major rating categories.

Such suffixes are added to Long-Term Issuer Default Ratings between AA and B. A BB rating is the fifth highest of 11 rating categories.

Ratings of individual securities or financial obligations of a corporate issuer address relative vulnerability to default on an ordinal scale. As of December 31, 2019**,** our senior unsecured rating was BB+. The Fitch rating system describes a BB rating as speculative. BB ratings indicate that there is an elevated vulnerability to default risk, particularly when faced with uncertainties or challenges in the business or economic environment over time. However, business and/or financial flexibility exists that supports the servicing of financial commitments. The modifiers + or - may be appended to a rating to denote relative status within major rating categories. Such suffixes are added to obligation rating categories, or to corporate finance obligation ratings between AA and CCC. A BB rating is the fifth highest of nine rating categories.

Moody's

Moody's Corporate Family Ratings (CFRs) are long-term ratings that reflect the relative likelihood of a default on a corporate family's debt and debt-like obligations and the expected financial loss suffered in the event of default. A CFR is assigned to a corporate family as if it had a single class of debt and a single consolidated legal entity structure. A CFR does not reference an obligation or class of debt and thus does not reflect priority of claim. As at December 31, 2019, our Corporate Family Rating was Ba1 with a stable outlook. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. Moody's appends the numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. The Ba rating category is the fifth highest rating out of nine rating categories.

Moody's long-term ratings are assigned to issuers or obligations with an original maturity of one year or more and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default. As of December 31, 2019, our senior unsecured long-term debt is rated Ba1 / LGD4 by Moody's. The Ba rating category is the fifth highest rating out of nine rating categories. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk.

Moody's Loss Given Default (LGD) assessments are opinions about expected loss given default expressed as a per cent of principal and accrued interest at the resolution of the default. One of the six LGD assessments are assigned to individual loan, bond, and preferred stock issues. The firm-wide or enterprise expected LGD rate generally approximates a weighted average of the expected LGD rates on the firm's liabilities (excluding preferred stock), where the weights equal each obligation's expected share of the total liabilities at default. As of December 31, 2019, our Loss Given Default Assessment from Moody's was LGD4 which represents a loss range of greater than or equal to 50 per cent and less than 70 per cent. LGD4 is the fourth highest assessment category out six categories.

S&P

A Standard & Poor's issuer credit rating is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. As at December 31, 2019, our issuer credit rating was BB+ with a stable outlook with S&P. This is the fifth highest of 11 ratings categories. Although less vulnerable than other speculative issuers, an obligor rated BB is regarded as having a degree of speculative characteristics. When faced with uncertainties or challenges in the business, financial, or economic environment, entities rated ‘BB’ may in-turn face challenges meeting their financial commitments. The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

A Standard & Poor's issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (including ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion reflects Standard & Poor's view of the obligor's capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. This is the fifth highest of 11 ratings categories. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

The Standard & Poor's Canadian preferred share rating scale serves issuers, investors, and intermediaries in the Canadian financial markets by expressing preferred share ratings (determined in accordance with global rating criteria) in terms of rating symbols that have been actively used in the Canadian market over a number of years. A Standard & Poor's preferred share rating on the Canadian scale is a forward-looking opinion about the creditworthiness of an

obligor with respect to a specific preferred share obligation issued in the Canadian market, relative to preferred shares issued by other issuers in the Canadian market. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on the global debt rating scale of Standard & Poor's. Each of our outstanding Preferred Shares Series have been rated P-34(High) by S&P. The P-4(High) rating is the fourth highest of eight categories. A P-4(High) rating corresponds to a B+ rating on the global preferred share rating scale. Obligors rated BB, B, CCC, and CC are regarded as having significant speculative characteristics, of which BB indicates the least degree of speculation and CC the highest. While such obligors will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. An obligor rated 'B' is less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitments.

We are focused on maintaining a strong financial position and cash flow coverage ratios to support our business. Our available credit facilities, funds from operations and debt financing options provide us with financial flexibility. As a result, we can be selective as to if and when we go to the capital markets for funding.

Note Regarding Credit Ratings

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

We have paid fees for rating services to DBRS, Fitch, Moody's and S&P during the last two years. We have also paid fees to DBRS for certain other services provided to the Corporation during the last two years.

DIVIDENDS

Common Shares

Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, our results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

TransAlta has declared and paid the following dividends per share on its outstanding common shares for the past three years:

Period		Dividend per Common Share
2017	First Quarter	$0.04
	Second Quarter	$0.04
	Third Quarter	$0.04
	Fourth Quarter	$0.04
2018	First Quarter	$0.04
	Second Quarter	$0.04
	Third Quarter	$0.04
	Fourth Quarter	$0.04
2019	First Quarter	$0.04
	Second Quarter	$0.04
	Third Quarter	$0.04
	Fourth Quarter	$0.04

Preferred Shares

TransAlta has declared and paid the following dividends per share on its outstanding preferred shares for the past three years:

Series A Shares

Period	Dividend per Series A Share
2017 First Quarter	$0.16931
Second Quarter	$0.16931
Third Quarter	$0.16931
Fourth Quarter	$0.16931
2018 First Quarter	$0.16931
Second Quarter	$0.16931
Third Quarter	$0.16931
Fourth Quarter	$0.16931
2019 First Quarter	$0.16931
Second Quarter	$0.16931
Third Quarter	$0.16931
Fourth Quarter	$0.16931

Series B Shares

Period	Dividend per Series B Share
2017 First Quarter	$0.15651
Second Quarter	$0.15645
Third Quarter	$0.16125
Fourth Quarter	$0.17467
2018 First Quarter	$0.17889
Second Quarter	$0.19951
Third Quarter	$0.20984
Fourth Quarter	$0.22301
2019 First Quarter	$0.23073
Second Quarter	$0.23136
Third Quarter	$0.23422
Fourth Quarter	$0.23113

Series C Shares

Period	Dividend per Series C Share
2017 First Quarter	$0.2875
Second Quarter	$0.2875
Third Quarter	$0.25169
Fourth Quarter	$0.25169
2018 First Quarter	$0.25169
Second Quarter	$0.25169
Third Quarter	$0.25169
Fourth Quarter	$0.25169
2019 First Quarter	$0.25169
Second Quarter	$0.25169
Third Quarter	$0.25169
Fourth Quarter	$0.25169

Series E Shares

Period	Dividend per Series E Share
2017 First Quarter	$0.3125
Second Quarter	$0.3125
Third Quarter	$0.3125
Fourth Quarter	$0.32463
2018 First Quarter	$0.32463
Second Quarter	$0.32463
Third Quarter	$0.32463
Fourth Quarter	$0.32463
2019 First Quarter	$0.32463
Second Quarter	$0.32463
Third Quarter	$0.32463
Fourth Quarter	$0.32463

Series G Shares

Period	Dividend per Series G Share
2017 First Quarter	$0.33125
Second Quarter	$0.33125
Third Quarter	$0.33125
Fourth Quarter	$0.33125
2018 First Quarter	$0.33125
Second Quarter	$0.33125
Third Quarter	$0.33125
Fourth Quarter	$0.33125
2019 First Quarter	$0.33125
Second Quarter	$0.33125
Third Quarter	$0.33125
Fourth Quarter	$0.31175

MARKET FOR SECURITIES

Common Shares

Our common shares are listed on the Toronto Stock Exchange (the "TSX") under the symbol "TA" and the New York Stock Exchange (the "NYSE") under the symbol "TAC". The following table sets forth the reported high and low trading prices and trading volumes of our common shares as reported by the TSX for the periods indicated:

Month	Price ($)		Volume
	High	Low	
2019			
March	10.04	7.84	21,770,128
April	10.14	8.96	16,108,565
May	9.17	8.54	16,291,015
June	8.96	7.87	15,161,974
July	8.57	7.89	8,593,480
August	8.76	7.60	8,338,545
September	9.01	8.39	8,572,313
October	8.81	7.55	7,866,106
November	9.02	7.59	10,594,762
December	9.41	8.64	11,019,292
2020			
January	9.96	8.56	12,431,669
February	11.23	9.76	19,683,522
March 1-2	10.47	9.92	1,830,908

Preferred Shares

Series A Shares

Our Series A Shares are listed on the TSX under the symbol "TA.PR.D".

Date of Issuance	Number of Securities [2]	Issue Price per Security	Description of Transaction
December 10, 2010[1]	12,000,000 Series A Shares	$25.00	Public Offering

Notes:

(1) Series A Shares were issued pursuant to a public offering by way of a prospectus supplement dated December 3, 2010 to a short form base shelf prospectus dated October 19, 2009.

(2) On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares on a one-for-one basis.

Month	Price ($) High	Price ($) Low	Volume
2019			
March	12.76	11.10	386,215
April	12.81	11.80	179,457
May	12.85	12.15	226,551
June	12.55	10.08	324,902
July	11.27	10.68	360,909
August	10.89	9.52	147,914
September	10.82	9.95	285,018
October	10.98	10.07	209,314
November	11.69	10.81	239,915
December	11.90	10.80	174,938
2020			
January	12.11	11.43	226,270
February	11.91	10.20	470,997
March 1-2	10.46	10.21	8,256

Series B Shares

Our Series B Shares are listed on the TSX under the symbol "TA.PR.E".

Date of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
March 31, 2016 (1)	1,824,620 Series B Shares	N/A	Conversion of Series A Shares

Note:

(1) On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares on a one-for-one basis.

	Price ($)		
Month	High	Low	Volume
2019			
March	13.38	12.10	29,003
April	13.51	12.82	20,861
May	13.30	12.50	62,546
June	13.10	10.64	83,324
July	11.71	11.11	32,500
August	11.65	10.39	42,765
September	11.66	10.31	45,590
October	11.65	10.77	26,939
November	12.30	11.00	57,931
December	12.10	11.16	42,324
2020			
January	13.08	11.64	12,397
February	12.35	9.57	40,391
March 1-2	11.10	11.10	100

Series C Shares

Our Series C Shares are listed on the TSX under the symbol "TA.PR.F".

Date of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
November 30, 2011 (1)	11,000,000 Series C Shares	$25.00	Public Offering

Note:

(1) Series C Shares were issued pursuant to a public offering by way of a prospectus supplement dated November 23, 2011 to a short form base shelf prospectus dated November 15, 2011.

	Price ($)		
Month	High	Low	Volume
2019			
March	16.44	14.15	107,828
April	16.24	15.42	45,787
May	16.00	14.72	113,260
June	14.87	12.26	250,279
July	14.05	12.95	530,299
August	13.21	12.40	211,361
September	14.15	12.66	278,007
October	14.24	13.42	569,238
November	14.93	14.10	307,553
December	15.11	14.00	121,892
2020			
January	15.44	14.70	282,429
February	15.19	13.51	105,334
March 1-2	13.70	13.35	16,500

Series E Shares

Our Series E Shares are listed on the TSX under the symbol "TA.PR.H".

Date of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
August 10, 2012 [1]	9,000,000 Series E Shares	$25.00	Public Offering

Note:

(1) Series E Shares were issued pursuant to a public offering by way of a prospectus supplement dated August 3, 2012 to a short form base shelf prospectus dated November 15, 2011.

	Price ($)		
Month	High	Low	Volume
2019			
March	19.11	16.70	320,252
April	19.16	17.60	70,091
May	18.76	17.31	77,571
June	17.69	14.55	305,563
July	16.94	16.00	328,030
August	16.38	15.13	132,458
September	16.60	15.14	553,855
October	16.59	15.92	337,964
November	17.30	16.41	233,758
December	17.31	16.35	154,732
2020			
January	17.74	16.96	255,685
February	17.45	15.72	162,972
March 1-2	16.16	15.85	12,600

Series G Shares

Our Series G Shares are listed on the TSX under the symbol "TA.PR.J".

Date of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
August 15, 2014 [1]	6,600,000 Series G Shares	$25.00	Public Offering

Note:

(1) Series G Shares were issued pursuant to a public offering by way of a prospectus supplement dated August 8, 2014 to a short form base shelf prospectus dated December 9, 2013.

	Price ($)		
Month	High	Low	Volume
2019			
March	20.00	17.47	108,296
April	19.99	18.76	52,981
May	19.49	18.40	53,490
June	18.73	15.53	95,481
July	17.35	16.15	267,796
August	16.50	15.28	119,202
September	16.85	15.25	243,134
October	16.79	16.07	114,074
November	17.60	16.65	141,404
December	17.99	16.46	146,931
2020			
January	18.48	17.60	106,547
February	18.10	16.26	141,552
March 1-2	16.52	16.35	1,600

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of our directors as at December 31, 2019, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve on the Board is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Rona H. Ambrose Alberta, Canada	2017	The Honourable Rona Ambrose is a national leader, former Leader of Canada's Official Opposition in the House of Commons and former leader of the Conservative Party of Canada. As a key member of the federal cabinet for a decade, Ms. Ambrose solved problems as a minister of the Crown across nine government departments, including serving as Vice Chair of the Treasury Board for several years and Chair of the cabinet committee for public safety, justice and Aboriginal issues. As the former environment minister responsible for the GHG regulatory regime in place across several industrial sectors, she understands the challenges facing the fossil fuel industry. Ms. Ambrose was personally responsible for the development of several federal policies, ranging from industrial strategies in military procurement to health innovation to improvements to sexual assault laws. Ms. Ambrose is a passionate advocate for women in Canada and around the world and led the global movement to create the "International Day of the Girl" at the United Nations. She was also responsible for ensuring that Aboriginal women in Canada were finally granted equal matrimonial rights. She successfully fought for the creation of a Canadian refugee program to bring Yazidi women and girls who have been sexually enslaved by ISIS to safety in Canada. Ms. Ambrose also serves on the advisory board of the Canadian Global Affairs Institute. Ms. Ambrose is also a director of Manulife Financial Corporation, Coril Holdings Ltd. and Andlauer Healthcare Group. She has a BA from the University of Victoria and an MA from the University of Alberta. She is also a graduate of the Harvard Kennedy School of Government Senior Leaders Program. Ms. Ambrose has an extensive track record of strong leadership acquired through a wide range of experience at the most senior levels of the Canadian government.
John P. Dielwart Alberta, Canada	2014	Mr. Dielwart is the Chair of the Governance, Safety and Sustainability Committee of the Board. The Board has appointed Mr. Dielwart as successor Chair of the Board to take effect immediately following the 2020 annual meeting of shareholders, subject to him being re-elected as a director at that meeting. Mr. Dielwart was formerly Chief Executive Officer of ARC Resources Ltd., which owns and operates oil and gas properties in Western Canada. He oversaw the growth of ARC Resources Ltd. from start-up in 1996 to a company with a total capitalization of approximately $10 billion at the time of his retirement. After his retirement from ARC Resources Ltd. on January 1, 2013, Mr. Dielwart re-joined ARC Financial Corp. ("ARC Financial") as Vice-Chairman. ARC Financial is Canada's leading energy-focused private equity manager. He is a member of ARC Financial's Investment and Governance committees, and currently represents ARC Financial on the boards of Modern Resources Ltd. and Aspenleaf Energy Limited. Prior to joining ARC Financial in 1994, Mr. Dielwart spent 12 years with a major Calgary-based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada. Mr. Dielwart has a Bachelor of Science with distinction (civil engineering) degree from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and is a past Chairman of the Board of Governors of the Canadian Association of Petroleum Engineers (CAPP). In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame and in 2018 he received the Oil and Gas Council's Canadian Lifetime Achievement Award. Mr. Dielwart is a director and former Co-Chair of the Calgary and Area Child Advocacy Centre. He is also a director of Crescent Point Energy Corp.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Dawn L. Farrell Alberta, Canada	2012	Mrs. Farrell became President and Chief Executive Officer of TransAlta Corporation on January 2, 2012. Prior to her appointment, she served as Chief Operating Officer from 2009 to 2011. Mrs. Farrell has over 34 years of experience in the electric energy industry, holding roles at TransAlta and BC Hydro. She has served as Executive Vice-President, Commercial Operations and Development; Executive Vice-President, Corporate Development; Executive Vice-President, Independent Power Projects; and Vice-President, Energy Marketing and IPP Development at TransAlta Corporation. From 2003 to 2006, Mrs. Farrell served as Executive Vice-President, Generation at BC Hydro. From 2006 to 2007, she served as BC Hydro's Executive Vice-President Engineering, Aboriginal Relations and Generation. Mrs. Farrell sits on the board of directors of The Chemours Company, an NYSE-listed chemical company, and the Alberta Business Council. Her past boards include The Conference Board of Canada, the Business Council of Canada, 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. Mrs. Farrell holds a Bachelor of Commerce with a major in Finance and a Master's degree in Economics from the University of Calgary. She has also attended the Advanced Management Program at Harvard University.
Robert C. Flexon Texas, U.S.A.	2019	Robert C. Flexon is the former President and Chief Executive Officer of Dynegy Inc. from 2011 until its acquisition by Vistra Energy Corp. in April 2018. Dynegy Inc. was a U.S. independent power producer engaged in the operation of power generating facilities and listed on the NYSE. Prior to Dynegy, Mr. Flexon also served as the Chief Financial Officer of UGI Corporation and also NRG Energy. In 2009, he served as President and CEO of Foster Wheeler's U.S. subsidiary and then he served as Chief Executive Officer of Foster Wheeler, a global engineering and construction contractor and power equipment supplier. Mr. Flexon has also held executive positions at NRG Energy, Inc. and has held key finance and accounting positions with Hercules, Inc. and Atlantic Richfield Company. Mr. Flexon serves on the Board of Directors of Capstone Turbine Corporation and Charah Solutions, Inc. Mr. Flexon holds a Bachelor of Science degree in Accounting from Villanova University. He also serves on the board of Genesys Works-Houston, an organization that transforms the lives of disadvantaged high school students through meaningful work experiences.
Alan J. Fohrer California, U.S.A.	2013	Mr. Fohrer was Chairman and Chief Executive Officer of Southern California Edison Company ("SCE"), a subsidiary of Edison International ("Edison") and one of the largest electric utilities in the United States. He was elected Chief Executive Officer in 2002 and Chairman in 2007. In 2000, Mr. Fohrer was elected as President and Chief Executive Officer of Edison Mission Energy ("EME"), a subsidiary of Edison that owns and operates independent power facilities. During his tenure at EME, Mr. Fohrer restructured a number of the international projects, which enhanced the value of the assets sold in subsequent years. Mr. Fohrer also served as Executive Vice-President, Treasurer and Chief Financial Officer of both Edison and SCE from 1995 to 1999. After 37 years with Edison, Mr. Fohrer retired in December 2010.Mr. Fohrer currently sits on the boards of PNM Resources, Inc., a publicly held energy holding company, Blue Shield of California, a non-profit health insurance provider, and Synagro, a waste management company. Mr. Fohrer has served on boards of directors of the Institute of Nuclear Power Operations, the California Chamber of Commerce, Duratek, Inc., and Osmose Utilities Services, Inc. He is also a member of the Viterbi School of Engineering Board of Councilors for the University of Southern California and Chair of the California Science Centre Foundation. Mr. Fohrer holds a Master of Science in civil engineering from the University of Southern California, Los Angeles, as well as a Master of Business Administration from California State University in Los Angeles.
Amb. Gordon D. Giffin Georgia, U.S.A.	2002	Ambassador Giffin is Senior Partner of the law firm of Dentons (formerly McKenna Long & Aldridge LLP), where he maintains offices in Washington, D.C. and Atlanta. His practice focuses on international transactions related to trade, energy and public policy. He has been engaged in the practice of law or government service for more than 40 years. He served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy from August 1997 to April 2001. Prior to that, he served as Chief Counsel and Legislative Director to United States Senator Sam Nunn, with responsibility for the legal and legislative operations of the office. Ambassador Giffin has spent three decades as an attorney in the energy industry as an advisor, trying multiple energy regulatory cases before state and federal tribunals and courts, and handling transactions including mergers and acquisitions. During a decade in public service, he was a senior attorney and advisor in the United States Senate where, among other matters, he worked on major energy public policy initiatives. During his four years as United States Ambassador to Canada, his responsibilities included the entire array of policy matters in the Canada-U.S. context including energy policy. He has substantial experience in dealing with issues at the intersection of industry and public policy. Since leaving public office, he resumed his continental law practice and remains actively engaged in public policy initiatives and international affairs through membership in the Council on Foreign Relations and the Trilateral Commission. Ambassador Giffin holds a Bachelor of Arts from Duke University (Durham, NC) and a Juris Doctorate from Emory University School of Law (Atlanta, GA).

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Harry Goldgut Ontario, Canada	2019	Mr. Goldgut is Vice Chair of Brookfield Asset Management's Renewable Group and Brookfield's Infrastructure Group and provides strategic advice related to Brookfield's open-end Infrastructure Fund. Mr. Goldgut was the CEO or Co-CEO and Chairman of Brookfield Renewable Power Inc., from 2000 to 2008, and thereafter, until 2015, he was Chairman of Brookfield's Power and Utilities Group. From 2015 to 2018, he served as Executive Chairman of Brookfield's Infrastructure and Power Groups. Mr. Goldgut joined Brookfield in 1997 and led the expansion of Brookfield's renewable power and utilities operations. He has had primary responsibility for strategic initiatives, acquisitions and senior regulatory relationships. He was responsible for the acquisition of the majority of Brookfield's renewable power assets. Mr. Goldgut also played a role in the restructuring of the electricity industry in Ontario as a member of several governmental committees, including the Electricity Market Design Committee, the Minister of Energy's Advisory Committee, the Clean Energy Task Force, the Ontario Energy Board (OEB) Chair's Advisory Roundtable and the Ontario Independent Electricity Operator (IESO) CEO Roundtable on Market Renewal. Mr. Goldgut also serves on the Boards of Directors of: Terraform Power, Inc. an owner and operator of a renewable power portfolio in North America and Western Europe, where he acts as Chair of the Nominating and Governance Committee; Isagen S.A. ESP, the third largest power generation company in Colombia; and the Princess Margaret Cancer Foundation. Mr. Goldgut attended the University of Toronto and holds an LL.B from York University's Osgoode Hall Law School.
Richard Legault Quebec, Canada	2019	Mr. Legault is Vice Chair of Brookfield's Renewable Group. Prior to his current role, Mr. Legault served as Chief Executive Officer of Brookfield Renewable Partners from 1999 to August 2015, during which time he led the growth of Brookfield's renewable power operations globally, helping to make Brookfield Renewable one of the world's largest publicly traded, pure play renewable power portfolios. From 2015 to 2018, he served as Executive Chairman of the Brookfield Renewable Group. Mr. Legault was Chief Financial Officer of Brookfield Asset Management from 2000 to 2001, prior to which he held several senior positions in operations, finance, and corporate development with Brookfield's forest products operations. Serving at Brookfield for over 31 years, Mr. Legault has been described as instrumental in developing Brookfield's renewable business, which is well-established in North America, South America and Europe. Mr. Legault also serves on the Board of Directors of Terraform Power, Inc., an owner and operator of a renewable power portfolio in North America and Western Europe; and Westinghouse Corporation, one of the largest nuclear technology and services companies globally, and serves as chair of its Risk Committee. Mr. Legault received a Bachelor of Accounting from the Université du Québec in Hull and is a member of the Chartered Professional Accountants of Canada (CPA, CA).
Yakout Mansour California, U.S.A.	2011	Mr. Mansour has over 40 years of experience as both a professional engineer and executive in the electric utility business in Canada, the United States, and abroad. He retired as President and Chief Executive Officer of the California Independent System Operator Corporation ("CAISO") in 2011, a position he had held since 2005. CAISO is responsible for operating and controlling 80 per cent of the California electric grid, designing and operating the California electricity market, and for settlements of over $8 billion annually. Under Mr. Mansour's leadership, the California market structure was completely redesigned, and CAISO established the market and technical foundation to accommodate one of the most aggressive renewable portfolio standards in the world. Prior to that, Mr. Mansour served in senior executive roles at BC Hydro and British Columbia Transmission Corporation where he was responsible for operation, asset management, and inter-utility affairs of the electric grid. In 2009, Mr. Mansour was named to the U.S. Department of Energy Electricity Advisory Committee as a vice chair. He also served on the various committees of the North American Electric Reliability Corporation and its predecessor organization, CEGRE, the Transmission Council of the Canadian Electric Association, and the Board of Directors of the Electric Power Research Institute. A Retired Professional Engineer and a Fellow of the Institute of Electrical and Electronics Engineers, Mr. Mansour has authored and co-authored numerous publications. He is recognized internationally in the field of power engineering and received several distinguished awards for his contributions to the industry. Mr. Mansour holds a Bachelor of Science in electrical engineering from the University of Alexandria (Alexandria, Egypt) and a Master of Science from the University of Calgary (Calgary, AB). Mr. Mansour brings to the Corporation and the Board decades of experience in our industry in generation, transmission and energy competitive markets in both a regulated and deregulated market environment. His technical and operational expertise provide an important diversity of thought and perspective to the Board.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Georgia R. Nelson Illinois, U.S.A.	2014	At TransAlta, Ms. Nelson is the Chair of the Human Resources Committee of the Board. Ms. Nelson was President and Chief Executive Officer of PTI Resources, LLC, an independent consulting firm, from 2005 to 2019. Ms. Nelson has had a 35-year career in the power generation industry, serving in various senior executive capacities for Edison International and its subsidiaries between 1971 and 2005. She was President of Midwest Generation Edison Mission Energy (EME), an independent power producer, from 1999 to her retirement in 2005 and General Manager of EME Americas, from 2002 to 2005. Ms. Nelson has extensive experience in electric and renewable energy operations, international business negotiations, environmental policy matters and human resources. Ms. Nelson is currently a director of Cummins Inc., Ball Corporation, and Sims Metal Management Ltd. She was a director of CH2MHILL Corporation, a privately held company, until December 2017. Ms. Nelson is a past director of Nicor, Inc. Ms. Nelson was a member of the Executive Committee of the National Coal Council from 2000 to 2015 and served as Chair from 2006 to 2008. She serves on the advisory committee of the Center for Executive Women at Northwestern University. Ms. Nelson was named to the 2012 National Association of Corporate Directors ("NACO") Directorship 100. She is an NACO Board Fellow. Ms. Nelson holds a Bachelor of Science from Pepperdine University and a Master of Business Administration from the University of Southern California.
Beverlee F. Park British Columbia, Canada	2015	Ms. Park is the Chair of the Audit, Finance and Risk Committee of the Board as of April 19, 2018. She is also a director and Chair of the Audit Committee of SSR Mining Inc. (TSX/NASDAQ-listed), a public mining company, focused on the operation, development, exploration and acquisition of precious metals projects in North and South America. Ms. Park was a member of the Board of Directors of Teekay LNG Partners where until June 2019 she chaired the Audit Committee. She was also a member of the Board of Governors at the University of British Columbia until June 30, 2018 where she chaired the Employee Relations Committee, and a member of the Board of Directors of InTransit BC until October 2018 where she chaired the Audit Committee. Ms. Park was previously a director of the BC Transmission Corporation, where she also chaired the Audit Committee and Capital Review Committee. Ms. Park has executive and board experience in a range of industries, including electricity transmission, forest products, shipping, mining, transportation and real estate. Ms. Park spent 17 years of her career with TimberWest Forest Corp. where she was most recently Chief Operations Officer until her retirement in 2013. During that time, she also held the roles of Interim Chief Executive Officer, President of the real estate division (Couverdon Real Estate) and Executive Vice President and Chief Financial Officer. Ms. Park holds a Bachelor of Commerce with distinction from McGill University (Montreal, QB), a Master of Business Administration from the Simon Fraser University Executive program and is also a Fellow of the Chartered Professional Accountants (FCPA) and Fellow of the Chartered Professional Accountants of British Columbia.
Bryan D. Pinney Alberta, Canada	2018	Bryan Pinney is the principal of Bryan D. Pinney Professional Corporation. Mr. Pinney is currently the lead director for North American Construction Group Ltd. He is also a director of a Hong Kong-listed oil and gas company, Persta Resources Inc., and of Sundial Growers Inc., a NASDAQ-listed company. Mr. Pinney was also the recent chair of the Board of Governors of Mount Royal University and has previously served on a number of non-profit boards. He is also a director of one private company. He is a Fellow of the Institute of Chartered Accountants, a Chartered Business Valuator and is a graduate of the Ivey Business School at the University of Western Ontario with an honours degree in Business Administration. He is also a graduate of the Canadian Institute of Corporate Directors. Mr. Pinney has over 30 years of experience serving many of Canada's largest corporations, primarily in energy and resources and construction. Mr. Pinney was a partner with Deloitte between 2002 and 2015. Mr. Pinney served as Calgary Managing Partner from 2002 through 2007 and as National Managing Partner of Audit & Assurance from 2007 to 2011 and Vice-Chair until June 2015. Mr. Pinney was a past member of Deloitte's Board of Directors and chair of the Finance and Audit Committee. Prior to joining Deloitte, Mr. Pinney was a partner with Andersen LLP and served as Calgary Managing Partner from 1991 through May of 2002.

Officers

The name, province or state and country of residence of each of our executive officers as at March 3, 2020, their respective position and office and their respective principal occupation are set out below.

Name	Principal Occupation	Residence
Dawn L. Farrell	President and Chief Executive Officer	Alberta, Canada
Wayne Collins	Executive Vice-President, Generation	Alberta, Canada
Dawn E. de Lima	Chief Shared Services Officer	Alberta, Canada
Jane Fedoretz	Chief Talent and Transformation Officer	Alberta, Canada
Brett M. Gellner	Chief Development Officer	Alberta, Canada
John H. Kousinioris	Chief Operating Officer	Alberta, Canada
Kerry O'Reilly Wilks	Chief Officer, Legal, Regulatory and External Affairs	Alberta, Canada
Todd J. Stack	Chief Financial Officer	Alberta, Canada

All of the executive officers of TransAlta have held their present principal occupation or position for the past five years, except for the following:

- Prior to August 2019, Ms. de Lima was Chief Officer, Business & Operational Services. Prior to July 2018, Ms. de Lima was Chief Administrative Officer. Prior to July 2015, Ms. de Lima was Chief Human Resources Officer of TransAlta. Prior to April 2012, Ms. de Lima was Chief Human Resources Officer and Executive Vice-President, Communications of TransAlta.
- Prior to August 2019, Mr. Gellner was Chief Investment and Strategy Officer. Prior to November 2018, Mr. Gellner was Interim Chief Financial Officer and Chief Strategy and Investment Officer of the Corporation. Prior to July 2018, Mr. Gellner was Chief Investment Officer of the Corporation. Prior to August 2013, Mr. Gellner was Chief Financial Officer of the Corporation.
- Prior to November 2018, Ms. Fedoretz was Counsel, Energy Group at Blake, Cassels & Graydon LLP.
- Prior to August 2019, Mr. Kousinioris was Chief Growth Officer. Prior to July 2018, Mr. Kousinioris was Chief Legal and Compliance Officer and Corporate Secretary of the Corporation. Prior to October 2015, Mr. Kousinioris was Chief Legal and Compliance Officer of TransAlta. Prior to December 2012, Mr. Kousinioris was a Partner and co-head of the Corporate Commercial Group at Bennett Jones LLP, Barristers and Solicitors.
- Prior to August 2019, Ms. O'Reilly Wilks was Chief Legal & Compliance Officer. Prior to November 2018, Ms. O'Reilly Wilks was Head of Legal, North Atlantic & UK, for Vale S.A. (Base Metal Business), one of the largest companies in the world.
- Prior to May 2019, Mr. Stack was Managing Director and Corporate Controller. Prior to February 2017, Mr. Stack was Managing Director and Treasurer of TransAlta. Prior to October 2015, Mr. Stack was Vice-President and Treasurer of TransAlta. Prior to November 2012, Mr. Stack was Treasurer of TransAlta.
- Prior to August 2019, Mr. Collins was Executive Vice President Coal and Mining Operations. Prior to May 2014, Mr Collins was Chief Operating Officer of Stanwell Corporation Limited in Australia.

As of March 3, 2020, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over less than one per cent of our outstanding common shares.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of TransAlta, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10 per cent of our common shares, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving TransAlta within the three most recently completed financial years or to date in 2020 or in any proposed transactions that has materially affected or will materially affect us.

In connection with the Brookfield investment, Mr. Richard Legault and Mr. Harry Goldgut were nominated by Brookfield and elected to the Board on April 26, 2019. See "*Directors and Officers*". Brookfield is also entitled to receive certain funding fees, management fees and interest and dividends on its $750 million investment. See "*General Development of the Business – Three Year History – Generation and Business Development – 2019 – Strategic Investment by Brookfield Renewable Partners*", and "*Capital and Loan Structure – Investment Agreement and E&O Agreement*".

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2019, there has been no indebtedness outstanding to TransAlta from any of our directors, executive officers, senior officers or associates of any such directors, nominees or senior officers.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders and Bankruptcies

Except as noted below, no director, executive officer or controlling security holder of TransAlta Corporation is, as at the date of this Annual Information Form, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

- was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Flexon was President and Chief Executive Officer and a director of Dynegy Inc., a power generating company that owns and operates a number of power stations in the US, from June 2011 to April 2018 when it was acquired by Vistra Energy Corp. Certain subsidiaries of Dynegy filed for bankruptcy in November 2011 under Chapter 11 of the US Bankruptcy Code. Mr. Flexon was also on the Board of Directors of Westmoreland Coal Company. On October 8, 2018, Westmoreland Coal Company filed for bankruptcy under Chapter 11 of the US Bankruptcy Code. Mr. Flexon resigned from the Board of Westmoreland Coal Company effective March 15, 2019.

Personal Bankruptcies

No director, executive officer or controlling security holder of TransAlta Corporation has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of TransAlta Corporation has:

- been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or
- been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, the Corporation believes that the following are material contracts, the particulars of which are disclosed elsewhere in this AIF, to which the Corporation or its subsidiaries are a party:

- Investment Agreement - See "*Capital and Loan Structure - Investment Agreement and E&O Agreement*".
- E&O Agreement - See "*Capital and Loan Structure - Investment Agreement and E&O Agreement*".
- Registration Rights Agreement - See "*Capital Structure - Registration Rights Agreement*".
- Off-Coal Agreement - See "*Business of TransAlta - Canadian Coal Business Segment - Off-Coal Agreement*".

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board serve as directors or officers of corporations which are in competition to the interests of TransAlta. No assurances can be given that opportunities identified by such member of the Board will be provided to us. However, our policies provide that each director and executive officer must comply with the disclosure requirements of the CBCA regarding any material interest. If a declaration of material interest is made, the declaring director shall not vote on the matter if put to a vote of the Board. In addition, the declaring director and executive officer may be requested to recuse himself or herself from the meeting when such matter is being discussed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TransAlta is occasionally named as a party in claims and legal proceedings which arise during the normal course of its business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claim may not have a material adverse effect on TransAlta. For further information, please refer to Note 35 of our audited consolidated financial statements for the year ended December 31, 2019, which financial statements are incorporated by reference herein. See "*Documents Incorporated by Reference*".

FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first dispute arose as a result of FMG's attempted termination of the South Hedland PPA on the basis that the conditions to establishing commercial operation under the South Hedland PPA had not been met. TransAlta's view is that all conditions to establishing commercial operation under the terms of the South Hedland PPA had been satisfied in full. TransAlta initiated legal action against FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. This matter is scheduled to proceed to trial beginning June 15, 2020.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

Mangrove

On April 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming TransAlta Corporation, the incumbent members of the Board of Directors of TransAlta Corporation on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is seeking to set aside the 2019 Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning September 14, 2020.

Line Loss Ruling

The Corporation has been participating in a line loss rule proceeding before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016 and issue a single invoice charging or crediting market participants for the difference in losses charges. A more recent decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was to be issued in April 2021, with cash settlement expected in June 2021. The current total estimate of exposure based on known data is $12 million. However, the AESO recently requested the AUC approve a pay-as-you-go settlement instead of issuing a single invoice. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, resulting in invoices being issued as early as April 2020 for settlement in June 2020, a year earlier than anticipated. The Corporation is challenging this request.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares and Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares is Computershare Investor Services Inc. Common shares are transferable in Vancouver, Calgary, Toronto, Montréal and Halifax. Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares are transferable in Calgary and Toronto. The transfer agent and registrar for our common shares in the United States is Computershare Trust Company at its principal office in Jersey City, New Jersey.

INTERESTS OF EXPERTS

The Corporation's auditors are Ernst & Young LLP, Chartered Professional Accountants, 2200, 215 – 2nd Street, S.W., Calgary, Alberta, T2P 1M4.

Our auditors, Ernst & Young LLP, are independent within the meaning of the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

ADDITIONAL INFORMATION

Additional information in relation to TransAlta may be found under TransAlta's profile on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans (all where applicable) is contained in our Management Proxy Circular for the most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from our Investor Relations department, or as filed on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Additional financial information is provided in our audited consolidated financial statements as at and for the year ended December 31, 2019, and in the related Annual MD&A, each of which is incorporated by reference in this AIF. See "*Documents Incorporated by Reference*".

AUDIT, FINANCE AND RISK COMMITTEE

General

The members of TransAlta's Audit, Finance and Risk Committee ("AFRC") satisfy the requirements for independence under the provisions of Canadian Securities Regulators, National Instrument 52-110 Audit Committees, Section 303A of the NYSE Rules and Rule 10A-3 under the U.S. Securities and Exchange Act of 1934. The AFRC's Charter requires that it be comprised of a minimum of three independent directors. The AFRC is currently comprised of four independent members: Beverlee F. Park (Chair), Robert C. Flexon, Alan J. Fohrer, and Bryan D. Pinney.

All members of the committee are financially literate pursuant to both Canadian and US securities requirements and Ms. Park, Mr. Flexon and Mr. Pinney have each been determined by the Board to be an "audit committee financial expert", within the meaning of Section 407 of the United States *Sarbanes Oxley Act of 2002* ("Sarbanes Oxley Act").

Mandate of the Audit, Finance and Risk Committee

The AFRC provides assistance to the Board in fulfilling its oversight responsibilities with respect to:

- the integrity of the Corporation's financial statements and financial reporting process,
- the systems of internal financial controls and disclosure controls established by management,
- the risk identification and assessment process conducted by management including the programs established by management to respond to such risks,
- the internal audit function,
- compliance with financial, legal and regulatory requirements and
- the external auditors' qualifications, independence and performance.

In so doing, it is the AFRC's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and management of the Corporation.

The function of the AFRC is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management of the Corporation is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and disclosure controls and procedures to comply with accounting standards, applicable laws and regulations which provide reasonable assurance that the assets of the Corporation are safeguarded and transactions are authorized, executed, recorded and properly reported.

While the AFRC has the responsibilities and powers set forth herein, it is not the duty of the AFRC to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors.

The AFRC must also designate at least one member as an "audit committee financial expert". The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the AFRC. Designation as an "audit committee financial expert" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the AFRC and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation's risks and the development and implementation of policies and procedures to mitigate such risks. The AFRC's role is to provide oversight in order to ensure that the Corporation's assets are protected and safeguarded within reasonable business limits. The AFRC reports to the Board on its risk oversight responsibilities.

Audit, Finance and Risk Committee Charter

The Charter of the AFRC is attached as Appendix "A".

Relevant Education and Experience of Audit, Finance and Risk Committee Members

The following is a brief summary of the education or experience of each member of the AFRC that is relevant to the performance of his or her responsibilities as a member of the AFRC, including any education or experience that has provided the member with an understanding of the accounting principles that we use to prepare our annual and interim financial statements.

Name of AFRC Member	Relevant Education and Experience
Robert C. Flexon	Mr. Flexon is the former President and Chief Executive Officer of Dynegy Inc. Prior to Dynegy, Mr. Flexon also served as Chief Financial Officer of UGI Corporation and also NRG Energy. Mr. Flexon has also held key finance and accounting positions with Hercules, Inc. and Atlantic Richfield Company. He holds a Bachelor of Science degree in Accounting from Villanova University.
Alan J. Fohrer	Prior to his retirement in December 2010, Mr. Fohrer was Chairman and CEO of SCE, a subsidiary of Edison and one of the largest electric utilities in the United States. Prior to that, Mr. Fohrer served as Executive Vice-President, Treasurer and Chief Financial Officer of both Edison and SCE. Mr. Fohrer also serves on the audit committee of PNM Resources Inc., a public company.
Beverlee . F. Park (Chair)	Ms. Park has executive experience in a range of industries, including forest products, shipping, mining, transportation, real estate, and electricity transmission. Ms. Park spent seventeen years of her career with TimberWest Forest Corp. where she was most recently Chief Operations Officer. Over that time, she also held the roles of Interim Chief Executive Officer, President of the real estate division (Couverdon Real Estate) and Executive Vice President and Chief Financial Officer. Ms. Park is currently a director of SSR Mining Inc. where she chairs the Audit Committee. She was formerly a director of Teekay LNG Partners, InTransit BC and BC Transmission Corp. where she chaired the audit committees of all these boards. Ms. Park holds a Bachelor of Commerce with distinction from McGill University (Montreal, QB), a Master of Business Administration from the Simon Fraser University Executive program and is a Chartered Accountant. She is also a Fellow of the Chartered Professional Accountants of British Columbia since 2011.
Bryan D. Pinney	Mr. Pinney has more than 30 years of experience in financial auditing, valuation and advising companies in energy and natural resources. He has been an Independent Director of North American Construction Group Ltd. since 2015 and its Lead Director since October 31, 2017. He is also a director of Sundial Growers Inc., a NASDAQ-listed company, where he also serves as Chair of the Audit & Risk Committee and is a member of the Human Resources & Compensation Committee and the Operations Committee. He served as Member of Deloitte's Board of Directors. He has been the Chair of the Board of Governors and Member of the Board of Governors of Mount Royal University from September 2014 and May 2009 respectively and has previously served on a number of nonprofit boards. He has been an Independent Non-Executive Director at Persta Resources Inc., a Hong Kong listed oil and gas exploration company. He has been a Chartered Accountant since December 1978, a Fellow of the Chartered Professional Accountants of Alberta since January 2009 and a Chartered Business Valuator of Canada since December 1990. Mr. Pinney obtained a Bachelor of Arts in Business Administration from the University of Western Ontario in 1975 and also completed the Directors Education Program offered by the Institute of Corporate Directors in Canada in 2012.

Other Board Committees

In addition to the AFRC, TransAlta has three other standing committees: the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee. The members of these committees as at December 31, 2019 are:

Governance, Safety and Sustainability Committee

Chair: John P. Dielwart
Rona H. Ambrose
Yakout Mansour
Georgia R. Nelson

Human Resources Committee

Chair: Georgia R. Nelson
Rona H. Ambrose
Alan J. Fohrer
Beverlee F. Park
Bryan D. Pinney

Investment Performance Committee

Chair: Robert Flexon
John P. Dielwart
Harry Goldgut
Richard Legault
Yakout Mansour

The Charters of the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee may be found on our website under Governance, Board Committees at www.transalta.com. Further information about the Board and our corporate governance may also be found on our website or in our Management Proxy Circular which is filed on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

For the years ended December 31, 2019 and December 31, 2018, Ernst & Young LLP and its affiliates billed $4,171,813 and $4,174,070, respectively, as detailed below:

Ernst & Young LLP

Year Ended December 31		**2019**		**2018**
Audit Fees[1]	$	2,475,985	$	2,652,152
Audit-related fees[1][2]		1,356,412		1,407,163
Tax fees		339,415		104,255
All other fees		—		10,500
Total	**$**	4,171,813	**$**	4,174,070

(1) Comparative figures have been reclassified to confirm to the current periods classification of fees.
(2) Included in the audit-related fees are $905,580 (2018 - $891.147) of fees billed to TransAlta Renewables.

No other audit firms provided audit services in 2019 or 2018.

The nature of each category of fees is described below:

Audit Fees

Audit fees are for professional services rendered for the audit and review of our financial statements or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents.

Audit-Related Fees

Assurance and related services that are reasonably related to the performance of the audit or review of our financial statements that are not included under "*Audit Fees*". Audit-Related fees include statutory audits, pension audits and other compliance audits. In 2019, we have included the fees billed to TransAlta Renewables, a controlled and consolidated subsidiary of TransAlta.

Tax Fees

Tax fees are tax-related services for review of tax returns, assistance with questions on tax audits, and tax planning.

All Other Fees

Products and services provided by the 'Corporation's auditor other than those services reported under "*Audit Fees*", "*Audit-Related Fees*" and "*Tax Fees*". This includes fees related to training services provided by the auditor.

Pre-Approval Policies and Procedures

The AFRC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the AFRC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the AFRC for other permissible categories of non-audit services, such categories being determined under the Sarbanes Oxley Act. This policy also provides that the Chair of the AFRC may approve permissible non-audit services during the quarter and report such approval to the AFRC at its next regularly scheduled meeting.

APPENDIX "A"

TRANSALTA CORPORATION

(the "Corporation")

AUDIT, FINANCE AND RISK COMMITTEE CHARTER

A. Establishment of Committee and Procedures

1. Composition of Committee

The Audit, Finance and Risk Committee (the "Committee") of the Board of Directors (the "Board") of TransAlta Corporation (the "Corporation") shall consist of not less than three Directors. All members of the Committee shall be determined by the Board to be independent as required under the provisions of Canadian Securities Regulators' Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange rules and Rule 10A-3 of the U.S. Securities and Exchange Act of 1934, as such rules apply to audit committee members. All members of the Committee must be financially literate pursuant to both Canadian and U.S. securities requirements and at least one member must be determined by the Board to be an "audit committee financial expert" within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"). Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the Board at the recommendation of the Governance, Safety and Sustainability Committee (the "GSSC").

2. Appointment of Committee Members

Members of the Committee shall be appointed from time to time by the Board, on the recommendation of the GSSC, and shall hold office until the next annual meeting of shareholders, or until their successors are earlier appointed, or until they cease to be Directors of the Corporation.

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and on the recommendation of the GSSC. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

4. Committee Chair

The Board shall appoint a Chair for the Committee on the recommendation of the GSSC.

5. Absence of Committee Chair

If the Chair of the Committee is not present at any meeting of the Committee, one of the members of the Committee who is present at the meeting shall be chosen by the Committee to preside at the meeting.

6. Secretary of Committee

The Committee shall appoint a Secretary who need not be a director of the Corporation.

7. Meetings

The Chair of the Committee may call a regular meeting of the Committee. The Committee shall meet at least quarterly and at such other time during each year as it deems appropriate to fulfill its responsibilities. In addition, the Chair of the Committee or any two members may call a special meeting of the Committee at any time.

The Committee shall also meet in separate executive session.

8. Quorum

A majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other shall constitute a quorum.

9. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing (including by way of written facsimile communication or email) to each member of the Committee at least 48 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive notice of a meeting; and attendance of a member at a

meeting constitutes a waiver of notice of the meeting, except where a member attends for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called. Notice of every meeting shall also be provided to the external and internal auditors.

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members, the President and Chief Executive Officer ("CEO"), other officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board generally not later than the next scheduled meeting of the Board.

12. Review of Charter and Evaluation of Committee

The Committee shall evaluate its performance and review and assess the adequacy of its Charter at least annually or otherwise, as it deems appropriate. All changes proposed by the Committee are reviewed and approved by the GSSC and the Board.

13. Outside Experts and Advisors

In consultation with the Board, the Committee Chair, on behalf of the Committee or any of its members, is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Duties and Responsibilities of the Chair

The fundamental responsibility of the Chair of the Committee is to effectively manage the duties of the Committee.

The Chair is responsible for:

1. Chairing meetings of the Committee and ensuring that the Committee is properly organized so that it functions effectively and meets its obligations and responsibilities.
2. Establishing the frequency of Committee meetings, duly convening the same and confirming that quorum is present when required.
3. Working with the CEO, the Chief Financial Officer (the "CFO"), the Corporate Secretary and Assistant Corporate Secretary, as applicable, on the development of agendas and related materials for the meetings.
4. Providing leadership to the Committee and assisting the Committee in ensuring the proper and timely discharge of its responsibilities.
5. Reporting to the Board on the recommendations and decisions of the Committee.

C. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls and disclosure controls established by Management, iii) the risk identification and assessment process conducted by Management including the programs established by Management to respond to such risks, iv) the internal audit function, v) compliance with financial, legal and regulatory requirements and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and Management of the Corporation.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management of the Corporation is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and disclosure controls and procedures to comply with accounting standards, applicable laws and regulations which provide reasonable assurance that the assets of the Corporation are safeguarded and transactions are authorized, executed, recorded and properly reported.

While the Committee has the responsibilities and powers set forth herein, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of Management and the external auditors.

The Committee must also designate at least one member as an "audit committee financial expert". The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "audit committee financial expert" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the Committee and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation's risks and the development and implementation of policies and procedures to mitigate such risks. The Committee's role is to provide oversight in order to ensure that the Corporation's assets are protected and safeguarded within reasonable business limits. The Committee reports to the Board on its risk oversight responsibilities.

D. Duties and Responsibilities of the Committee

1. Financial Reporting, External Auditors and Financial Planning

A) Duties and Responsibilities Related to Financial Reporting and the Audit Process

(a) Review with Management and the external auditors the Corporation's financial reporting process the work to be conducted in conjunction with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

(b) Review with Management and the external auditors the Corporation's audited annual financial statements, including the notes thereto, "Management's Discussion and Analysis", the related earnings release, and recommend their approval to the Board for release to the public;

(c) Review with Management and the external auditors the Corporation's interim financial statements, including the notes thereto, "Management's Discussion and Analysis", the related earnings release, and approve their release to the public as required;

(d) In reviewing the financial statements and related financial disclosure, the Committee shall review and discuss with Management and the external auditors:

(i) any changes in accounting principles, practices or policies considering their applicability to the business and financial impact;

(ii) Management's processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(iii) the use of "pro forma" or "non-comparable" information and the applicable reconciliation;

(iv) alternative treatments of financial information within generally accepted accounting principles that have been discussed between Management and the auditors, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditors; and

(v) disclosures made to the Committee by the CEO and CFO during their certification process for the relevant periodic/annual report filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation's disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving Management or other employees who have a significant role in the Corporation's internal controls is reported to the Committee.

(e) In reviewing the financial statements and related financial disclosure, the Committee shall also, with the external auditors:

(i) discuss the cooperation they received from Management during the course of their review and their access to all records, data and information requested; and

(ii) satisfy itself that there are no unresolved issues between Management and the external auditors that could reasonably be expected to materially affect the financial statements.

(f) Review quarterly with senior Management, the Chief Legal and Compliance Officer (or, as necessary, outside legal advisors), and the Corporation's internal and external auditors, the effectiveness of the Corporation's internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and the Corporation's policies;

(g) Review with Management and the external auditors the processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud, and the processes put in place for monitoring the risks within the targeted areas; and

(h) Discuss with Management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies.

B) Duties and Responsibilities Related to the External Auditors

(a) The Committee shall have direct responsibility for the compensation and oversight of the external auditors including nominating the external auditors to the Board for appointment by the shareholders at the Corporation's general annual meeting. In performing its function, the Committee shall:

(i) review and approve annually the external auditors audit plan;

(ii) review and approve the basis and amount of the external auditors' fees and ensure the Corporation has provided appropriate funding for payment of compensation to the external auditors;

(iii) subject to the delegation granted to the Chair of the Committee, pre-approve all audit related services including all non-prohibited non-audit services provided by the external auditors; the Chair of the Committee is authorized to approve all audit related services including non-prohibited non-audit services provided by the external auditors, and shall report all such approvals to the Committee at its next scheduled meeting;

(iv) review and discuss annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (a) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on their independence with the Corporation; (b) discussing with the external auditors any relationships or services that the external auditors believe may affect their objectivity and professional skepticism; (c) reviewing with the external auditors the experience and qualifications of the senior personnel who are providing audit services to the Corporation; (d) reviewing the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S. regulatory registration requirements; and (e) evaluating the communication and interaction with the external auditor including quality of service considerations;

(v) in the year preceding the change of the lead (or coordinating) audit partner (having primary responsibility for the audit), and in any event not less than every five years, perform a comprehensive review of the external auditor which takes into consideration (a) the impact of the tenure of the audit firm on audit quality, trends in the audit firm's performance and expertise in the industry, incidences of independence threats and the effectiveness of safeguards to mitigate those threats, (b) the responsiveness of the audit firm to changes in the entity's business

and suggestions for improvement from regulators, the audit committee and/or management, (c) the consistency and rigour of the professional skepticism applied by the external auditor, and the quality of the engagement team and its communications, review of Canadian Public Accountability Board (CPAB) inspection findings since the previous comprehensive review and how the audit firm responded to these findings, and following this comprehensive review, determine whether the audit firm should be nominated to the Board as the external auditors for appointment by the shareholders at the Corporation's next general annual meeting;

(vi) inform the external auditors and Management that the external auditors shall have direct access to the Committee at all times, as well as the Committee to the external auditors;

(vii) instruct the external auditors that they are ultimately accountable to the Committee as representatives of the shareholders of the Corporation; and

(viii) at least annually, obtain and review the external auditors' report with respect to the auditing firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm, any inquiry or investigation by governmental or professional authorities within the preceding five years undertaken respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues.

C) Duties and Responsibilities Related to Financial Planning

(a) Review and recommend to the Board for approval the Corporation's issuance and redemption of securities (including the review of all public filings to effect any of the issuances or redemptions), financial commitments and limits, and any material changes underlying any of these commitments;

(b) Review annually the Corporation's annual tax plan;

(c) Receive regular updates with respect to the Corporation's financial obligations, loans, credit facilities, credit position and financial liquidity;

(d) Review annually with Management the Corporation's overall financing plan in support of the Corporation's capital expenditure plan and overall budget/medium range forecast; and

(e) Review with Management at least annually the approach and nature of earnings guidance and financial information to be disclosed to analysts and rating agencies.

2. Internal Audit

(a) Approve whether the internal audit function should be outsourced and if outsourced, approve the audit firm to perform such internal audit service; provided that in no event shall the external auditor be retained to also perform the internal audit function;

(b) Review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with Management's response thereto;

(c) Review annually the scope and plans for the work of the internal audit group, the adequacy of the group's resources, the internal auditors' access to the Corporation's records, property and personnel;

(d) Recognize and advise senior Management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(e) Meet separately with Management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(f) Review with the Corporation's senior financial Management and the internal audit group the adequacy of the Corporation's systems of internal control and procedures; and

(g) Recommend to the Human Resources Committee the appointment, termination or transfer of the lead individual responsible for internal audit, provided that if the internal audit

function has been, or is being, outsourced to an audit firm, the Committee itself shall approve the appointment, termination or transfer of such audit firm.

3. Risk Management

The Board is responsible for ensuring that the Corporation has adopted processes and key policies for the identification, assessment and management of its principal risks. The Board has delegated to the Committee the responsibility for the oversight of Management's identification, and evaluation, of the Corporation's principal risks, and the implementation of appropriate policies, processes and systems to manage or mitigate the risks within the Corporation's risk appetite. The Committee reports to the Board thereon.

The Committee shall:

(a) Review, at least quarterly, Management's assessment of the Corporation's principal risks; discuss with Management the processes for the identification of these risks and the efficacy of the policies and procedures for mitigating and/or addressing these risks;

(b) Receive and review Managements' quarterly risk update including an update on residual risks;

(c) Review the Corporation's enterprise risk management framework and reporting methodology;

(d) Review annually the Corporation's Financial and Commodity Exposure Management Policies and approve changes to such policies;

(e) Review and approve the Corporation's strategic hedging program, guidelines and risk tolerance;

(f) Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(g) Review the Corporation's annual insurance program, including the risk retention philosophy, potential exposure and corporate liability protection programs;

(h) Periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external counsel concerning risk management and review their performance in relation to such roles and responsibilities; and

(i) Annually, together with Management, report and review with the Board:

(i) the Corporation's principal risks and overall risk appetite/profile;

(ii) the Corporation's strategies in addressing its risk profile;

(iii) the processes, policies, procedures and controls in place to manage or mitigate the principal risks; and

(iv) the overall effectiveness of the enterprise risk management process and program.

4. Governance

A) Public Disclosure, Legal and Regulatory Reporting

(a) On behalf of the Committee, the Chair shall review all public disclosure inclusive of material financial information extracted or derived from the Corporation's financial statements prior to dissemination to the public;

(b) Review quarterly with the Chief Legal and Compliance Officer, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the Corporation's financial statements;

(c) Discuss with the external auditors their perception of the Corporation's financial and accounting personnel, any recommendations which the external auditors may have, including those contained in the Management letter, with respect to improving internal financial controls, choice of accounting principles or management reporting systems, and review all Management letters from the external auditors together with Management's written responses thereto;

(d) Review with Management, the external auditors and internal legal counsel (external counsel if necessary), any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these may be or have been disclosed in the financial statements;

(e) Review annually the Insider Trading Policy and approve changes as required; and

(f) Review annually the Corporation's Disclosure Policy and Social Media Policy to ensure continued applicability with the law and the Corporation's disclosure principles.

B) Pension Plan Governance

(a) Review annually the Annual Pension Report and financial statements of the Corporation's pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs, and reporting thereon to the Board annually; and

(b) Together with the Human Resources Committee of the Board, review annually, and as required, the overall governance of the Corporation's Pension Plans, approving the broad objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon to the Board annually.

C) Information Technology - Cyber Security

(a) Receive bi-annually a system status update with respect to the Corporation's core IT operating systems; and

(b) Review annually the Corporation's cyber security programs and their effectiveness. Receive an update on the Corporation's compliance program for cyber threats and security.

D) Administrative Responsibilities

(a) Review the annual audit of expense accounts and perquisites of the Directors, the CEO and the CEO's direct reports and their use of corporate assets;

(b) Establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal and disclosure controls or auditing matters and the confidential, anonymous submission by employees, contractors, shareholders and other stakeholders of concerns regarding accounting, auditing, ethical or legal violations;

(c) Review all incidents, complaints or information reported through the Ethics Help Line and/or Management;

(d) Initiate investigations of complaints or allegations as necessary, report to the Board thereon and ensure that appropriate action is taken as necessary to address the matter;

(e) Review and approve the Corporation's hiring policies for employees or former employees of the external auditors and monitor the Corporation's adherence to the policy; and

(f) Report annually to shareholders on the work of the Committee during the year.

E) Compliance and Powers of the Committee

(a) The responsibilities of the Committee comply with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition, this Charter complies with applicable U.S. laws, such as the Sarbanes-Oxley Act and the rules and regulations adopted thereunder, and with the New York Stock Exchange's corporate governance standards, as they exist on the date hereof.

(b) The Committee may, at the request of the Board or on its own initiative, investigate such other matters as are considered necessary or appropriate in carrying out its mandate.

APPENDIX "B"

GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

"**AESO**" – Alberta Electric System Operator.

"**AEMO**" – Australian Energy Market Operator.

"**Air Emissions**" – Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury, and GHGs.

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

"**AUC**" – Alberta Utilities Commission.

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

"**Balancing Pool**" – The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the *Electric Utilities Act* (effective June 1, 2003) and the *Balancing Pool Regulation*. For more information go to www.balancing pool.ca

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

"**Capacity**" – The rated continuous load-carrying ability, expressed in MW, of generation equipment.

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

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

"**eERP**" – ecoEnergy for Renewable Power program, a program established by the federal Government of Canada.

"**ESG**" – Environmental, Social and Governance

"**FNTP**" – Full Notice To Proceed. Written notice given to the contractor fully authorizing them to proceed with the work.

"**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.

"**GGPPA**" – *Greenhouse Gas Pollution Pricing Act* (Canada).

"**GHG**" **-** Greenhouse gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

"**Gigawatt**" – A measure of electric power equal to 1,000 MW.

"**GWh**" **-** Gigawatt hour – A measure of electricity consumption equivalent to the use of 1,000 MW of power over a period of one hour.

"**IESO**" – Independent Electricity System Operator.

"**LNTP**" – Limited Notice To Proceed. Written notice given to the contractor authorizing them to proceed with the work in a limited manner in accordance with the notice.

"**LTC**" – Long term contract.

"**MMcf/d**" - Million cubic feet of gas per day – A measure of natural gas.

"**MW**" **-** Megawatt – A measure of electric power equal to 1,000,000 watts.

"**MWh**" - Megawatt hour – A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

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

"**NOx**" **–** Nitrogen Oxide.

"**OBPS**" – Output Based Pricing Standard.

"**OEFC**" – Ontario Electricity Financial Corporation.

"**Off-Coal Agreement**" – Off-Coal Agreement dated November 24, 2016 between, among others, TransAlta and Her Majesty the Queen in Right of Alberta.

"**PPA**" – Purchase power agreement.

"**Renewables PPA**" – Long-term power purchase agreements with certain subsidiaries of TransAlta Renewables providing for the purchase by TransAlta, for a fixed price, of all of the power produced at such subsidiaries.

"**SO2**" **–** Sulphur Dioxide.

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

"**TA Cogen**" – TransAlta Cogeneration LP.

"**tCO2e/GWh**" – Tonnes of carbon dioxide equivalent per gigawatt hour.

"**TSX**" – Toronto Stock Exchange.

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

Management's Discussion and Analysis

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our 2019 audited annual consolidated financial statements (the "consolidated financial statements") and our 2020 annual information form ("AIF"), each for the fiscal year ended Dec. 31, 2019. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Dec. 31, 2019. All dollar amounts in the tables are in millions of Canadian dollars unless otherwise noted and except amounts per share, which are in whole dollars to the nearest two decimals. All other dollar amounts in this MD&A are in Canadian dollars, unless otherwise noted. This MD&A is dated Mar. 3, 2020. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us" or the "Corporation"), including our AIF, is available on SEDAR at ***www.sedar.com****, on EDGAR at* ***www.sec.gov*** *and on our website at* ***www.transalta.com****. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

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

In particular, this MD&A contains forward-looking statements including, but not limited to: operating performance and transition to clean power generation, including our goal to have no generation from coal by the end of 2025; the Clean Energy Investment Plan and the benefits thereof; transitioning to 100 per cent clean electricity by 2025; the source of funding for the Clean Energy Investment Plan; our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2020 to 2031 and beyond; potential for growth in renewables and on-site and cogeneration assets, including demand therefor and greenfield development acquisitions; the amount of capital allocated to new growth or development projects and funding thereof; our business, anticipated future financial performance and anticipated results, including our outlook and performance targets; our expectation that the $400 million second tranche of the investment by Brookfield Renewable Partners and its affiliates ("Brookfield") will close in October 2020; the benefit of the Brookfield Investment, including as it pertains to our expected success in executing on our growth projects, including expanding in the US renewable market and advancing our on-site and cogeneration business; the timing and the completion of growth and development projects, and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend and maintenance, and the variability of those costs; the conversion or repowering of our coal-fired units to natural gas, and the timing and costs thereof; expectations relating the benefits of the conversions and repowering; the terms of the current or any further proposed share buy back programs, including timing and number of shares to be repurchased pursuant to any normal course issuer bid and the acceptance thereof by the Toronto Stock Exchange ("TSX"); the mothballing of certain units; the impact of certain hedges on future earnings, results and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity, including for clean energy, in both the short term and long-term, and the resulting impact on electricity prices; the impact of load growth, increased capacity and natural gas and other fuel costs on power prices; expectations in respect of generation availability, capacity and production; expectations regarding the role that different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our marketing and trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense and the adequacy of tax provisions; changes in accounting estimates and accounting policies; the mitigation of risks and effectiveness thereof, including as it pertains to climate change risk, environmental management, cybersecurity, commodity prices and fuel supply; anticipated growth rates and competition in our markets; our expectations and obligations and anticipated liabilities relating to the outcome of existing or potential legal and contractual claims, regulatory investigations and disputes, including the litigation with Fortescue Metals Group Ltd. relating to the South Hedland facility and the Mangrove (as defined below) proceedings relating to the Brookfield investment, each discussed further below; ability to achieve 2020 ESG (as defined below) targets; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; and our credit practices.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the investment and credit markets; Alberta spot power price being equal to $53 to $63 per megawatt hours ("MWh") in 2020; Mid-C spot power prices equal to US$25 to US$35 per MWh in 2020; sustaining capital in 2020 being between $170 million and $200 million; productivity capital of $10 million to $15 million; discount rates; our proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion or repowering; assumptions regarding the ability of the converted units to successfully compete in the Alberta energy market; and assumptions regarding our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables and being able to realize the full economic benefit from the capacity, energy and ancillary services from our Alberta hydro assets once the applicable power purchase arrangement ("PPA") has expired; our being successful in defending against the claims alleged by Mangrove, discussed further below; the second $400 million tranche of the Brookfield investment closing as anticipated in October 2020; the Brookfield investment and its related arrangements with TransAlta having the expected benefits to the Corporation; and the higher adjusted EBITDA anticipated from our Alberta hydro assets subject to the Brookfield investment being realized.

Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include, but are not limited to, risks relating to: fluctuations in market prices; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic or market conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather and other climate-change related risks; unexpected increases in cost structure; disruptions in the source of fuels, including natural gas required for the conversions and repowering, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; natural and manmade disasters, including those resulting in dam or dyke failures; the threat of domestic terrorism and cyberattacks; pandemic or epidemics and any associated impact on supply chain; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all; commodity risk management and energy trading risks; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects or delays in the closing of acquisitions; increased costs or delays in the construction or commissioning of pipelines to converted units; changes in expectations in the payment of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; downgrades in credit ratings; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation, including as it pertains to establishing commercial operations at the South Hedland facility and in relation to the Brookfield investment; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2019.

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

Business Model

Our Business

We are one of Canada's largest publicly traded power generators with over 108 years of operating experience. We own, operate and manage a highly contracted and geographically diversified portfolio of assets representing 8,385 MW[(1)] of capacity and use a broad range of generation fuels that include coal, natural gas, water, solar and wind. Our energy marketing operations maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions.

Vision and Values

Our vision is to be a leader in clean electricity – committed to a sustainable future. We apply our expertise, scale and diversified fuel mix to capitalize on opportunities in our core markets and grow in areas where our competitive advantages can be employed. Our values are grounded in safety, innovation, sustainability, integrity and respect, which together create a strong corporate culture that allows our people to work on a common ground and understanding. These values are at the heart of our success.

Strategy for Value Creation

Our goals are to deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share. We strive for a low to moderate risk profile over the long-term while balancing capital allocation and maintaining financial strength to allow for financial flexibility. Our segmented cash flow growth is driven by optimizing and diversifying our existing assets and further expanding our overall portfolio and presence in Canada, the United States of America ("US") and Australia. We are focusing on these geographic areas as our expertise, scale and diversified fuel mix create a competitive advantage that we can leverage to capture expansion opportunities in these core markets to create shareholder value.

Material Sustainability Impacts

Sustainability means ensuring that our financial returns consider short- and long-term economics, environmental impacts and societal and community needs. This MD&A integrates our financial and sustainability or Environment, Social and Governance ("ESG") reporting. Key elements of our sustainability disclosure are guided by our sustainability materiality assessment. To help inform discussion and provide context on how ESG affects our business, we have referenced the provincial securities commission guidance, Global Reporting Index, Sustainability Accounting Standards Board and the Task Force on Climate-related Financial Disclosures. Our content is structured following guidance on non-traditional capitals from the International Integrated Reporting Framework. In addition, we track the performance of 80 sustainability-related Key Performance Indicator ("KPIs") and have obtained a limited assurance report from Ernst & Young LLP over material KPIs.

(1) We measure capacity as net maximum capacity (see the Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated, and reflect the basis of consolidation of underlying assets.

Corporate Strategy

Our strategic focus is to invest in a disciplined manner in a range of clean and renewable technologies such as wind, hydro, solar, battery and thermal (natural gas-fired and cogeneration) that produce electricity for industrial customers and communities to deliver returns to our shareholders.

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017. TransAlta is currently pursuing opportunities of $1.8 billion to $2.0 billion as part of this plan, including approximately $800 million of renewable energy projects either recently completed or already under construction. The implementation and execution of TransAlta's Clean Energy Investment Plan, including the acceleration of certain features of that plan, is in large part being facilitated by the $750 million strategic investment by Brookfield that we announced in March 2019 in response to feedback received from our shareholders during extensive engagement held in 2018 and 2019. The first $350 million tranche of Brookfield's investment closed in May 2019 and facilitated the acceleration of our coal-to-gas conversion plan discussed below. The second $400 million tranche of Brookfield's investment, anticipated to close in October 2020, will help further the advancement and implementation of the remainder of our Clean Energy Investment Plan, including our expected growth in renewables, while helping the Corporation maintain a strong balance sheet and financial flexibility to carry out the other pillars of our strategy discussed below. Refer to the Significant and Subsequent Events section of this MD&A for further details.

On Jan. 16, 2020, TransAlta announced near-term objectives that further support the Clean Energy Investment Plan. In addition, we announced our 2020 sustainability targets. For further details, refer to the 2020 Sustainable Development Targets section of this MD&A.

Our strategic priorities are focused on the following outcomes:

1. Successfully execute our coal-to-gas conversions

We are transitioning our Alberta thermal fleet to natural gas, as part of our Clean Energy Investment Plan. We plan to invest between $800 million to $1.0 billion to convert or repower our Alberta thermal fleet to natural gas. This will repurpose and reposition our fleet to a cleaner gas-fired fleet and advance our leadership position in onsite generation while generating attractive returns by leveraging the Corporation's existing infrastructure.

TransAlta's Clean Energy Investment Plan includes converting three of our existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The cost to convert each unit is expected to be approximately $30 to $35 million per unit.

The Clean Energy Investment Plan also includes permitting to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined-cycle facility while achieving a similar heat rate. The Clean Energy Investment Plan assumes there are no delays in securing the natural gas supply requirements, which may result from regulatory or other constraints.

The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of our Alberta thermal assets; and
- Significantly reducing air emissions and costs.

The following key achievements over the past year helped us advance this part of our strategy:

On Dec. 17, 2018, the Corporation exercised our option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater Midstream and Infrastructure Ltd. ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, was approximately $100 million.

In 2019, we issued Full Notice to Proceed ("FNTP") to convert Sundance Unit 6 and Keephills Unit 2 to natural gas by replacing the existing coal burners with natural gas burners. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020 and Keephills Unit 2 by the first half of 2021.

We expect to issue Limited Notice to Proceed ("LNTP") for Keephills Unit 3 during the first half of 2020 and expect to complete the conversion of that unit during 2021. We are evaluating the potential to install dual fuel capability at Keephills Unit 3 to ensure we have optimal fuel flexibility as we transition the fleet from coal to gas, and to manage any timing delays in obtaining full gas requirements that may occur due to regulatory or other constraints.

We are currently seeking regulatory permits to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined- cycle facility while achieving a similar heat rate.

To advance this repowering strategy, on Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F-class gas turbines and related equipment for $84 million. These turbines will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. We expect to issue LNTP in 2020 and FNTP in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined- cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million, well below a greenfield combined-cycle project. In conjunction with the Sundance Unit 5 permitting, we are also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined-cycle unit, depending on market fundamentals. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of greenhouse gas ("GHG") costs, starting in late 2023 with Shell Energy North America (Canada).

2. Deliver growth in our renewables fleet

We are further expanding our renewables platform. We currently have over $400 million of renewable energy construction projects to be completed in 2020 and 2021. We completed and commissioned two wind farms in 2019 investing over $340 million through TransAlta Renewables. Our focus is to ensure that we solidify returns through exceptional project execution and integration where we are able to commission and operate assets within our schedule and cost objectives.

The following key achievements in 2019 helped us advance this part of our strategy:

US Wind Projects

In 2019, we completed the construction of two wind projects (collectively, the "US Wind Projects") in the Northeastern US. The Big Level wind project ("Big Level") acquired on Mar. 1, 2018, consists of a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. The Antrim wind project ("Antrim") acquired on Mar. 28, 2019 consists of a 29 MW project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. Big Level and Antrim began commercial operations on Dec. 19, 2019, and Dec. 24, 2019, respectively. The US Wind Projects have added an additional 119 MW of generating capacity to our Wind and Solar portfolio.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs.

Windrise Wind Project

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the Alberta Electric System Operator ("AESO") as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise wind project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta, and is expected to cost approximately $270 million to $285 million. The project development work is on schedule. Windrise has secured approval for the facility from the Alberta Utilities Commission ("AUC") and is currently permitting transmission lines required to connect the facility to the Alberta grid. Construction activities will start in the second quarter of 2020 and the project is on track to reach commercial operation during the first half of 2021.

Skookumchuck Wind Project
On Apr. 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind project, a 136.8 MW wind project currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy. TransAlta has the option to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be approximately $150 million to $160 million, a portion of which is expected to be funded with tax equity financing.

WindCharger Project
During the first quarter of 2019, TransAlta approved the WindCharger project, an innovative energy storage project, which will have a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview Wind Farm Substation. WindCharger will store energy produced by the nearby Summerview II Wind Farm and discharge into the Alberta electricity grid at times of peak demand. This project is expected to be the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the AUC and an interconnection application to the AESO, were submitted in 2019. AUC approval was granted in November 2019 and the AESO approval is expected by the end of the first quarter of 2020. Detailed engineering designs, as well as the procurement of long-lead equipment, has been completed. Construction is on track to begin in March 2020 with a commercial operation date expected within the second quarter of 2020. The total expected cost of the project to TransAlta is $7 million to $8 million.

3. Expand presence in the US renewables market

We are focusing our business development efforts in the renewables segment of the US market. Demand for new renewables in the US is expected to grow in the near term. We currently have 2,000 MW at different stages in our development pipeline. These opportunities are expected to grow TransAlta Renewables, utilize its excess debt capacity and deliver stable dividends back to TransAlta.

In addition to the US Wind Projects and the Skookumchuk wind project discussed above, during 2019, TransAlta acquired a portfolio of wind development projects in the US. If we decide to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025. If a decision is made to not move forward with a project or the costs are no longer considered to be recoverable, the costs are charged to earnings. Estimated returns on these projects and similar projects are sufficient to recover costs of unsuccessful development projects.

4. Advance and expand our on-site generation and cogeneration business

We will grow our on-site and cogeneration asset base, a business segment we have deep experience in, having provided on-site cogeneration services to various customers since the early 1990s. Our current pipeline under evaluation is approximately 900 MW and our technical design, operations experience and safety culture make us a strong partner in this segment. We see this segment growing as industrial and large-scale customers are looking to find solutions to help lower costs of power production, replace aging or inefficient equipment, reduce network costs and meet their ESG objectives.

Consistent with this strategy, on Oct. 1, 2019, TransAlta and SemCAMS announced that they entered into definitive agreements to develop, construct and operate a cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

The highly efficient cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights. The development of the cogeneration facility at Kaybob South No. 3 is expected to eliminate the need for traditional boilers and reduce annual carbon emissions of the operation by approximately 100,000 tonnes carbon dioxide equivalent ("CO_2e"), which is equivalent to removing 20,000 vehicles off Alberta roads.

5. Maintain a strong financial position

We intend to remain disciplined in our capital investment strategy and continue to build on our already strong financial position.

We currently have access to $1.7 billion in liquidity, including $411 million in cash. During 2019, we entered into transactions to strengthen our position to execute on the Clean Energy Investment Plan including: (i) entering into an investment agreement with Brookfield providing us with $750 million in strategic financing, (ii) increasing our credit facilities by $200 million to a total of $2.2 billion and extending the maturity of the term by one year, and (iii) successfully obtaining US$126 million of tax equity financing associated with the US Wind Projects.

To further this strategy in 2020, we will repay the $400 million bond maturing in November 2020 and continue our share buyback program in an amount up to $80 million.

The Clean Energy Investment Plan will be funded from the cash raised through the strategic investment by Brookfield, cash generated from operations and raising capital through TransAlta Renewables. For further details on the Brookfield investment, refer to the Significant and Subsequent Events section of this MD&A.

In addition, we continue to execute on our multi-year Greenlight program that is focused on transforming our business and delivering TransAlta's strategy by reducing our cost structure. The program is entering its fourth year since implementation, and with each passing year it creates a continuous improvement culture that improves the way employees work together to deliver better business results. The program is focused on creating a structure around our people that enables them to identify, develop and deliver projects that improve performance across the Corporation with an emphasis on delivering sustainable value and cash flow improvements. Through the program, we have instituted ways to optimize our assets, minimize GHG emissions, reduce capital and operating costs, improve fuel usage and streamline processes. As this approach is increasingly embedded into the Corporation it has increased the empowerment of our employees, strengthened our processes and improved our corporate culture while reducing our operating costs.

Growth and coal-to-gas conversion expenditures

Our growth projects are focused on sustaining our current operations and supporting our growth strategy in our Clean Energy Investment Plan. A summary of the significant growth and major projects that are in progress is outlined below:

	Total project				
	Estimated spend	Spent to date[1]	Estimated spend in 2020	Target completion date	Details
Project					
Big Level wind development project[2]	225 - 240	234	4	Commissioned	90 MW wind project with a 15-year PPA
Antrim wind development project[3]	100 - 110	106	—	Commissioned	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	95 - 100	100	—	Commissioned	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Skookumchuck wind development project[4,5]	150 - 160	—	80	Q2 2020	Option to purchase a 49 per cent ownership in the 136.8 MW wind project with a 20-year PPA
Windrise wind development project[5]	270 - 285	49	233	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery[5,6]	7 - 8	1	6	Q2 2020	10 MW/20 MWh utility-scale storage project
Boiler conversions	100 - 200	28	69	2020 to 2022	Coal-to-gas conversions at Canadian Coal
Repowering	750 - 770	85	20	2023	Repower the steam turbines at Sundance Unit 5
Kaybob cogeneration project[5]	105 - 115	17	59	Q4 2021	40 MW cogeneration project with SemCAMS under a 13-year fixed price contract
Total	**1,802 - 1,988**	**620**	**471**		

(1) Represents cumulative amounts spent as of Dec. 31, 2019.
(2) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is approximately US$173 million to US$185 million, spent to date is US$179 million and estimated remaining spend in 2020 is US$3 million. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(3) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is approximately US$77 million to US$85 million, spent to date is US$80 million and estimated remaining spend in 2020 is nil. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(4) The estimated spend in 2020 assumes the project will receive tax equity financing for the remainder of the total project spend.
(5) These projects will potentially be dropped down to TransAlta Renewables.
(6) Net of expected government reimbursements.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2019	2018	2017
Revenues	**2,347**	2,249	2,307
Fuel, carbon compliance and purchased power	**1,086**	1,100	1,016
Operations, maintenance and administration	**475**	515	517
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Cash flow from operating activities	**849**	820	626
Comparable EBITDA[1,2,3]	**984**	1,161	1,030
Funds from operations[1,3]	**757**	927	804
Free cash flow[1,3]	**435**	524	328
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.86)	(0.66)
Funds from operations per share[1,3]	**2.67**	3.23	2.79
Free cash flow per share[1,3]	**1.54**	1.83	1.14
Dividends declared per common share	**0.12**	0.20	0.12
Dividends declared per preferred share[4]	**0.78**	1.29	0.77

As at Dec. 31	2019	2018	2017
Total assets	**9,508**	9,428	10,304
Total consolidated net debt[1,5]	**3,110**	3,141	3,363
Total long-term liabilities[6]	**4,329**	4,414	4,311

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and the remaining $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019 ("PPA Termination Payments"). See the Significant and Subsequent Events section for further details.
(4) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(5) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease obligations, net of available cash and cash equivalents, the principal portion of restricted cash on TransAlta OCP and the fair value of economic hedging instruments on debt. See the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.
(6) Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

At the end of 2018, we had a number of contracts expire, which impacted our comparable EBITDA. Through our strong performance in 2019, we recovered a significant amount of these expected declines through innovation, cost reductions and higher revenue from our Energy Marketing segment.

Revenues in 2019 were $2,347 million, up $98 million compared to 2018, mainly as a result of strong revenue generated from our Energy Marketing segment as well as higher production, resulting in higher revenue, within the US Coal segment due to the strong merchant pricing in the Pacific Northwest.

Comparable EBITDA decreased by $177 million compared to 2018. After adjusting for the PPA Termination Payments in 2019 and 2018, comparable EBITDA decreased by $76 million for the year ended Dec. 31, 2019, compared to 2018. This decrease was expected as a result of the expiry of the Mississauga contract and lower scheduled payments on the Poplar Creek contract. Strong performance at the Canadian Coal and Energy Marketing segments as well as lower Corporate costs have significantly offset this expected decrease. Comparable EBITDA for the year ended Dec. 31, 2019, was negatively impacted by the unplanned outage at US Coal during the first quarter of 2019.

At Canadian Coal, comparable EBITDA improved in 2019 due to the combined impact of higher realized prices as a result of greater merchant production, increased co-firing resulting in lower fuel, carbon compliance and purchased power costs, as well as lower operations, maintenance and administration ("OM&A") costs. In addition, performance from our Energy Marketing segment was stronger than 2018, particularly from US Western and Eastern markets due to continued high levels of volatility across North American power markets.

Free cash flow ("FCF"), one of the Corporation's key financial metrics, totalled $435 million, down $89 million compared to last year. FCF, after adjusting for the PPA Termination Payments, increased $12 million compared to last year, primarily as a result of lower sustaining and productivity capital expenditures and lower distributions paid to subsidiaries' non-controlling interests. Significant changes in segmented cash flows are highlighted in the Segmented Comparable Results within this MD&A.

OM&A expense for the year-ended Dec. 31, 2019, decreased by $40 million compared to 2018. This decline in OM&A is largely due to lower costs in our Canadian Coal and Corporate segments and ongoing streamlining of our workforce. Lower salary, contractor and materials expenses were partially offset by higher legal fees.

Fuel, carbon compliance and purchased power costs were lower in 2019 compared to 2018. This decrease was mainly due to our increased gas supply available for co-firing, as a result of the Corporation transporting natural gas on the Pioneer Pipeline earlier than expected. Co-firing, when economical, allows us to produce fewer GHG emissions than coal combustion, which lowers our GHG compliance costs.

Net earnings attributable to common shareholders for the year ended Dec. 31, 2019, were $52 million, compared to a loss of $248 million in the prior year. Increased earnings were partially driven by the Keephills 3 and Genesee 3 swap with Capital Power Corporation that closed in the fourth quarter of 2019, where we recognized a gain on termination of the coal rights contract of $88 million and a gain on the sale of Genesee 3 of $77 million, in addition to the $56 million PPA Termination Payments received during the third quarter of 2019. Excluding the PPA Termination Payments and impairment charges in both years, as well as the gains related to Keephills 3 and Genesee 3 in 2019, we have a net loss of $20 million in 2019 compared to a net loss of $174 million in 2018. Stronger earnings are attributable to stronger performance at Canadian Coal and Energy Marketing, strong Alberta pricing, the Alberta tax rate reduction, lower OM&A costs and lower interest expense, partially offset by other losses on sale of property, plant and equipment ("PP&E").

Ability to Deliver Financial Results

The metrics we use to track our performance are comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA"), funds from operations ("FFO") and FCF. The overall performance of our portfolio was in line with our 2019 outlook. The Corporation is within the upper end of the revised FCF target of $350 million to $380 million, excluding the impact of the PPA Termination Payments. Reported FCF benefited from the receipt of $56 million from the Balancing Pool on settlement of the termination of the Sundance B and C PPA dispute.

The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		**2019**	2018	2017
Comparable EBITDA	Target[1]	**875-975**	1,000-1,050	1,025-1,100
	Actual[2]	**984**	1,161	1,030
	Adjusted Actual[3]	**928**	1,004	996
FCF	Target[1]	**350-380**	300-350	270-310
	Actual	**435**	524	328
	Adjusted Actual[3]	**379**	367	311

(1) Represents our revised outlook. Due to strong results from our Canadian Coal segment, in the fourth quarter of 2019, we revised our FCF target from a range of $270 million to $330 million to a range of $350 million to $380 million. As a result of strong performance in the first quarter of 2018, we revised the following 2018 targets: comparable EBITDA from the previously announced target range of $950 million to $1,050 million to $1,000 to $1,050 million, FCF target range from $275 million to $350 million to the target range of$300 million to $350 million. In the second quarter of 2017, we reduced the following 2017 targets: Comparable EBITDA from target range of $1,025 million to $1,135 million to $1,025 to $1,100 million, FCF target range from $300 million to $365 million to the target range of $270 million to $310 million.

(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

(3) 2019 and 2018 were adjusted for the PPA Termination Payments as these were not included in the targets. 2017 amounts were adjusted to remove the impact related to the Ontario Electricity Financial Corporation ("OEFC") indexation dispute: Comparable EBITDA was reduced by $34 million and FCF was reduced by $17 million.

Significant and Subsequent Events

Investor Day

On Sept. 16, 2019, TransAlta held our 2019 Investor Day, and announced our Clean Energy Investment Plan. See the Corporate Strategy section of this MD&A for additional 2019 significant events to advance our Clean Energy Investment Plan.

In addition, the Corporation announced that it adopted, based on TransAlta level deconsolidated cash flows, a deconsolidated Debt/EBITDA target of 2.5 to 3.0 times, and a dividend policy of returning between 10 and 15 per cent of TransAlta deconsolidated FFO to common shareholders. The credit metrics and dividend policy are being presented on a deconsolidated basis, allowing investors to understand how the dividends received from TransAlta Renewables and TransAlta Cogeneration L.P. ("TA Cogen") are either being returned or invested for TransAlta shareholders. See the Key Financial Ratios section of this MD&A for further details.

On Jan. 16, 2020, the Board declared a quarterly dividend of $0.0425 per common share payable on Apr. 1, 2020, to shareholders of record at the close of business on Mar. 2, 2020, which represents a 6.25 per cent increase in our dividend level.

Strategic Investment by Brookfield

Following extensive engagement by the Corporation with several of its shareholders, on Mar. 25, 2019, the Corporation announced it entered into an agreement (the "Investment Agreement") whereby Brookfield agreed to invest $750 million (the "Investment") in the Corporation. The Investment provides the financial flexibility to drive TransAlta's transition to 100 per cent clean electricity by 2025, recognizes the anticipated future value of TransAlta's Alberta Hydro Assets and accelerates the Corporation's plan to return capital to its shareholders. As discussed in the Corporate Strategy section of this MD&A, the Brookfield Investment was key to the implementation and advancement of the Corporation's Clean Energy Investment Plan, including facilitating or accelerating several key pillars of the Corporations' strategic plan.

Under the terms of the Investment Agreement, Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs were recognized as part of the carrying value of the unsecured subordinated debentures issued at that time.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share. In connection with the Investment, Brookfield nominated and TransAlta shareholders elected two experienced officers of Brookfield, Harry Goldgut and Richard Legault, to our Board of Directors at the 2019 Annual and Special Meeting of shareholders. TransAlta and Brookfield intend to work together to complete TransAlta's transition to clean electricity, maximize the value of the Alberta Hydro Assets and create long-term shareholder value.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee
consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation and maximizing the value of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the OM&A expense on the statement of earnings (loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment (which occurred on May 1, 2019).

Additional details about the Investment can be found in our material change report dated Mar. 26, 2019, available electronically on SEDAR at www.sedar.com and on EDGAR at www.sec.gov as well as in our AIF. Copies of the Investment Agreement, together with copies of the exchangeable debenture issued to Brookfield on May 1, 2019, the registration rights agreement entered into with Brookfield in respect of common shares held in TransAlta, and the exchange and option agreement with Brookfield governing the terms of the exchange of the exchangeable securities issued under the Investment, are also available on SEDAR and on EDGAR. Shareholders are urged to read these documents in their entirety.

On Apr. 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020. See the Other Consolidated Analysis section of this MD&A for additional information on the Mangrove proceedings.

Normal Course Issuer Bid

On May 27, 2019, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement a Normal Course Issuer Bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may purchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, no more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended Apr. 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million.

Termination of the Alberta Sundance PPAs with the Balancing Pool

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective Mar. 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective Mar. 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on Mar. 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation which the Corporation pursued from the Balancing Pool through an arbitration initiated under the PPAs. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full additional amount it was seeking to recover, being $56 million, plus GST and interest.

TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The Keephills 3 facility is a 463 MW coal-fired generating facility located approximately 70 kilometres west of Edmonton, Alberta, adjacent to TransAlta's existing Keephills Unit 1 and Unit 2 power plants. The Keephills 3 facility achieved commercial operation in 2011 and has been identified as a candidate for TransAlta's intended coal-to-gas conversions.

The transaction price for each non-operating interest largely offset each other, resulting in a payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

The Corporation early-adopted amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test, that the Corporation elected to apply to its acquisition of the non-operating interest in Keephills 3. As a result, on the transaction closing of Oct. 1, 2019, the acquisition has been accounted for as an asset acquisition and the transaction price was allocated based on the relative fair values of those assets and liabilities as at the date of the acquisition. The transaction price of $301 million was allocated as follows: working capital of $11 million, PP&E of $308 million, other assets of $3 million, less other liabilities of $2 million and decommissioning and other provisions of $19 million. The net increase to our PP&E balance relating to Keephills 3 and Genesee 3 swap, including the impact of shortening the useful lives of the coal assets at Keephills 3, is estimated to increase depreciation expense in 2020 by approximately $72 million.

As a result of the sale of our interest in Genesee 3, we recognized a gain on sale of approximately $77 million in the fourth quarter.

On closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. The Sunhills mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. Upon termination of this agreement in the fourth quarter of 2019, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings.

Board of Director Changes

On Jan. 16, 2020, we announced that the Board has appointed John P. Dielwart as Chair of the Board, upon his re-election as an independent director at TransAlta's next annual shareholder meeting and immediately following Ambassador Gordon Giffin's retirement from the Board. As previously announced, Ambassador Giffin is retiring from the Board in 2020 after serving as Chair since 2011.

Mr. Dielwart has served as an independent director on the Board since 2014, and currently serves as the Chair of the Governance, Safety and Sustainability Committee. He is also on the Investment Performance Committee of the Board and has previously served on the Audit, Finance and Risk Committee. Mr. Dielwart is a founder and director of ARC Resources Ltd. from 1996 to present and served as Chief Executive Officer of ARC Resources Ltd. from 2001 to 2013. Mr. Dielwart earned a Bachelor of Science (Distinction) in Civil Engineering from the University of Calgary, is a member of the Association of Professional Engineers and Geoscientists of Alberta and a Past-Chairman of the Board of Governors of the Canadian Association of Petroleum Producers. Mr. Dielwart is also a director and former Co-Chair of the Calgary and Area Child Advocacy Centre. In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame.

On Jan. 25, 2019, we also announced the retirement decision of Timothy Faithfull. In 2018, Mr. Faithfull indicated to the Board his intention to retire from the Board of Directors immediately following TransAlta's 2019 Annual Shareholders Meeting.

Management Changes

On July 18, 2019, the Corporation appointed John Kousinioris as Chief Operating Officer of TransAlta Corporation. Mr. Kousinioris previously held the roles Chief Growth Officer and Chief Legal and Compliance Officer and Corporate Secretary at TransAlta. In the role of Chief Growth Officer, Mr. Kousinioris was responsible for overseeing the areas of business development, gas and renewables operations, commercial and energy marketing. Mr. Kousinioris also remains the President of TransAlta Renewables.

On May 16, 2019, the Corporation promoted Todd Stack to Chief Financial Officer. Mr. Stack, who has served as Managing Director and Corporate Controller of the Corporation since February 2017, has been responsible for providing leadership and direction over TransAlta's financial activities, corporate accounting, reporting, tax and corporate planning. Since joining TransAlta in 1990, Mr. Stack has acted as the Corporation's Treasurer and Corporate Controller, as well as a member of the corporate development team reviewing greenfield and acquisition opportunities. Prior to joining the finance team at TransAlta, Mr. Stack held a number of roles in the engineering team, including design, operations and project management.

Mothballing of Sundance Units

On Mar. 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from Apr. 1, 2020. The extensions were requested by TransAlta based on our assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

Financing of the US Wind Projects

TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta Power Ltd. ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the US Wind Projects were funded by tax equity financing and TransAlta Renewables. As at Dec. 31, 2019, TransAlta Renewables funded these costs by acquiring tracking preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity.

Big Level and Antrim began commercial operation on Dec. 19, 2019, and Dec. 24, 2019, respectively. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US$85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the statements of financial position.

Refer to the Corporate Strategy section of this MD&A for further updates on ongoing projects.

Refer to Note 4 of the consolidated financial statements within our 2019 Annual Integrated Report for significant events impacting both prior and current year results.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2019, 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 to provide management and investors with an understanding of our financial position and results. Certain financial measures discussed in this MD&A are not defined under IFRS, are not standard measures under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Comparable EBITDA, deconsolidated Comparable EBITDA, FFO, deconsolidated FFO, FCF, total net debt, total consolidated net debt, adjusted net debt, deconsolidated net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Discussion of Consolidated Financial Results, Segmented Comparable Results, Selected Quarterly Information, Key Financial Ratios and Financial Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Discussion of Consolidated Financial Results

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, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, under comparable EBITDA we reclassify certain transactions to facilitate the discussion of the performance of our business:

- During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
- Any gains or losses on asset sales are not included as these are not part of ongoing operations.
- Certain assets we own in Canada (and in Australia in 2017) are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We depreciate these assets over their expected lives.
- We also reclassify the depreciation on our mining equipment from fuel, carbon compliance and purchased power to reflect the actual cash cost of our business in our comparable EBITDA.
- In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator ("IESO") relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") effective Jan. 1, 2017. Under the new NUG Contract, we received fixed monthly payments until 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 recorded the payments we received as revenues as a proxy for operating income, and depreciated the facility until Dec. 31, 2018.
- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.
- In October 2019, we acquired Capital Power's 50 per cent ownership of Keephills 3 in exchange for selling our 50 per cent ownership in the Genesee 3 facility to Capital Power, and we now own 100 per cent of the Keephills 3 facility. As a result, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. Upon termination of this agreement in the fourth quarter of 2019, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings. On a comparable basis, we removed this gain from 2019 results.
- Asset impairment charges (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.

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

Year ended Dec. 31	**2019**	2018	2017
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Net earnings attributable to non-controlling interests	**94**	108	42
Preferred share dividends	**30**	50	30
Net earnings (loss)	**176**	(90)	(118)
Adjustments to reconcile net income to comparable EBITDA			
Income tax expense (recovery)	**17**	(6)	64
Gain on sale of assets and other	**(46)**	(1)	(2)
Foreign exchange loss	**15**	15	1
Net interest expense	**179**	250	247
Depreciation and amortization	**590**	574	635
Comparable reclassifications			
Decrease in finance lease receivables	**24**	59	59
Mine depreciation included in fuel cost	**121**	140	75
Australian interest income	**4**	4	2
Unrealized mark-to-market (gains) losses	**(33)**	38	(32)
Adjustments to earnings to arrive at comparable EBITDA			
Impacts to revenue associated with certain de-designated and economic hedges	**—**	—	2
Impacts associated with Mississauga recontracting[1]	**—**	105	77
Gain on termination of Keephills 3 coal rights contract	**(88)**	—	—
Asset impairment charge[2]	**25**	73	20
Comparable EBITDA	**984**	1,161	1,030
Comparable EBITDA - excluding the PPA Termination Payments	**928**	1,004	1,030

(1) Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2018, are as follows: revenue ($108 million) and fuel and purchased power and de-designated hedges ($3 million). Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2017, are as follows: revenue ($101 million), fuel and purchased power and de-designated hedges ($12 million), operations, maintenance and administration ($3 million) and recovery related to a renegotiated land lease ($9 million).
(2) Asset impairment charges for 2019 primarily includes the $141 million increase for the decommissioning and restoration liability at the Centralia mine, the $15 million for trucks held for sale and written down to net realizable value and the $18 million write-off of project development costs, partially offset by a $151 million impairment reversal at US Coal (2018 - $38 million charge related to the retirement of Sundance Unit 2, Lakeswind and Kent Breeze impairment of $12 million and a write-off of project development costs of $23 million; 2017 - $20 million retirement of Sundance Unit 1).

Funds from Operations and Free Cash Flow

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

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

Year ended Dec. 31	2019	2018	2017
Cash flow from operating activities[1]	**849**	820	626
Change in non-cash operating working capital balances	**(121)**	44	114
Cash flow from operations before changes in working capital	**728**	864	740
Adjustments			
Decrease in finance lease receivable	**24**	59	59
Other	**5**	4	5
FFO	**757**	927	804
Deduct:			
Sustaining capital[2]	**(141)**	(150)	(218)
Productivity capital	**(9)**	(21)	(24)
Dividends paid on preferred shares	**(40)**	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(111)**	(169)	(172)
Payments on lease obligations[2]	**(21)**	(18)	(17)
Other	**—**	(5)	(5)
FCF	**435**	524	328
Weighted average number of common shares outstanding in the year	**283**	287	288
FFO per share	**2.67**	3.23	2.79
FCF per share	**1.54**	1.83	1.14

(1) 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

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

Year ended Dec. 31	2019	2018	2017
Comparable EBITDA[1]	**984**	1,161	1,030
Provisions and other	**13**	(9)	(3)
Interest expense	**(174)**	(187)	(218)
Current income tax expense	**(35)**	(28)	(23)
Realized foreign exchange gain (loss)	**(6)**	5	15
Decommissioning and restoration costs settled	**(34)**	(31)	(19)
Other cash and non-cash items	**9**	16	22
FFO	**757**	927	804
Deduct:			
Sustaining capital[2]	**(141)**	(150)	(218)
Productivity capital	**(9)**	(21)	(24)
Dividends paid on preferred shares	**(40)**	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(111)**	(169)	(172)
Payments on lease obligations[2]	**(21)**	(18)	(17)
Other	**—**	(5)	(5)
FCF	**435**	524	328

(1) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change. 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

Supplemental disclosure	2019	2018	2017
FFO - excluding the PPA Termination Payments	**701**	770	804
FCF - excluding the PPA Termination Payments	**379**	367	328
FFO per share - excluding the PPA Termination Payments	**2.48**	2.68	2.79
FCF per share - excluding the PPA Termination Payments	**1.34**	1.28	1.14

For explanations for the current period, refer to the Highlights section of this MD&A.

Higher FCF in 2018 compared to 2017 was also driven by strong cash flow from operating activities due to the receipt of the $157 million PPA Termination Payments in 2018 related to the termination of the Sundance B and C PPAs, as well as reduced sustaining and productivity capital expenditures.

Segmented Comparable Results

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

The table below shows the segmented cash flow generated by the business by each of our segments:

Year ended Dec. 31	2019	2018	2017
Segmented cash flow[1]			
Canadian Coal[2]	**214**	279	175
US Coal	**54**	63	33
Canadian Gas[3]	**99**	228	221
Australian Gas	**112**	136	127
Wind and Solar	**206**	211	201
Hydro	**93**	96	61
Generation segmented cash flow	**778**	1,013	818
Energy Marketing	**105**	33	39
Corporate	**(92)**	(107)	(108)
Total segmented cash flow	**791**	939	749
Total segmented cash flow - excluding the PPA Termination Payments	**735**	782	749

(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(3) 2017 includes $34 million from the OEFC relating to the 2017 indexation dispute.

Segmented cash flow generated by the business, after adjusting for the PPA Termination Payments, was down $47 million in 2019 compared to 2018, mainly due to the expiry of the Mississauga NUG Contract and lower scheduled repayments on the Poplar Creek finance lease, partially offset by strong cash flow from Energy Marketing as well as lower sustaining capital expenditures. Cash flow in 2018 was $33 million higher than 2017 due to lower sustaining capital expenditures and higher Ancillary Services revenue from our hydro facilities.

Canadian Coal

Year ended Dec. 31	2019	2018	2017
Availability (%)	**89.2**	91.6	82.0
Contract production (GWh)	**6,927**	8,936	18,683
Merchant production (GWh)	**5,932**	5,304	3,786
Total production (GWh)	**12,859**	14,240	22,469
Gross installed capacity (MW)[1]	**3,229**	3,231	3,791
Revenues[2]	**823**	901	996
Fuel, carbon compliance and purchased power	**449**	526	510
Comparable gross margin	**374**	375	486
Operations, maintenance and administration	**138**	171	192
Taxes, other than income taxes	**13**	13	13
Termination of Sundance B and C PPAs	**(56)**	(157)	—
Net other operating income	**(40)**	(41)	(40)
Comparable EBITDA[2]	**319**	389	321
Deduct:			
Sustaining capital:			
Routine capital	**15**	17	22
Mine capital	**23**	42	28
Planned major maintenance	**34**	15	54
Total sustaining capital expenditures[3]	**72**	74	104
Productivity capital	**6**	12	12
Total sustaining and productivity capital[3]	**78**	86	116
Provisions	**(6)**	(10)	5
Payments on lease obligations[3]	**16**	14	14
Decommissioning and restoration costs settled	**17**	19	11
Other	**—**	1	—
Canadian Coal cash flow	**214**	279	175

(1) 2019 & 2018 - includes 774 MW for Sundance Units 3 and 5, which are temporarily mothballed; 2017 includes 1,334 MW for Sundance Units 1, 2, 3 and 5, which were temporarily mothballed. Sundance Unit 1 was retired on Jan. 1, 2018, and Sundance Unit 2 was retired on July 31, 2018. The Keephills 3 and Genesee 3 asset swap resulted in a net 2 MW reduction of capacity.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) On implementation of IFRS 16 in 2019, we removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line in arriving at segmented cash flow.

Supplemental disclosure	2019	2018	2017
Comparable EBITDA - excluding the PPA Termination Payments	**263**	232	321
Canadian Coal cash flow - excluding the PPA Termination Payments	**158**	122	175

2019
Availability for the year was lower compared to 2018, due to planned outages at our Keephills 1 and Sundance 4 units, whereas 2018 only had one outage at one of our non-operated units; this was partially offset by fewer unplanned losses in 2019.

Production for the year ended Dec. 31, 2019, decreased 1,381 gigawatt hours ("GWh") compared to 2018, primarily due to the mothballing of certain Sundance units and planned outages, partially offset by lower unplanned outages. Lower contract production was partially offset by higher merchant production.

Revenue for the year ended Dec. 31, 2019, decreased by $78 million compared to 2018, mainly due to lower production as a result of the termination of the Sundance B and C PPAs on Mar. 31, 2018.

Revenue per MWh of production rose to approximately $64 per MWh in 2019 from $63 per MWh in 2018. Revenues in the first quarter of 2018 included the Sundance B and C PPA revenue as well as the passthrough revenues associated with carbon compliance costs, which are no longer recoverable on the Sundance units as the PPAs have been terminated.

Fuel, carbon compliance and purchased power costs per MWh were lower in 2019 compared to 2018. Cost per MWh of production fell to approximately $35 per MWh in 2019 from $37 per MWh in 2018. Consequently, comparable gross margin per MWh for 2019 improved by approximately $3 per MWh compared to 2018.

We continued to co-fire with natural gas, when economical. Natural gas combustion produces fewer GHG emissions than coal combustion, which lowers our GHG compliance costs. In addition, fuel costs can be lower by co-firing, depending on the market price for natural gas. On Nov. 1, 2019, the firm contract to transport natural gas on the Pioneer Pipeline began, which substantially increased gas quantities available to us and increased our supply available to co-fire.

OM&A costs were lower in 2019 compared to 2018, as a result of the full year impact of cost reductions progressively implemented over the preceding year. These cost reductions arose from a combination of factors including fewer units operating, lower capacity factor operation on merchant units, co-firing with gas, and operations and maintenance work optimization.

Excluding the PPA Termination Payments, comparable EBITDA for the year ended Dec. 31, 2019, increased $31 million compared to 2018. This largely reflects lower fuel, carbon compliance, and purchased power costs, as well as lower OM&A costs.

For the year ended Dec. 31, 2019, sustaining capital expenditures decreased by $2 million compared to 2018, mainly due to less mine development work being completed in 2019, partially offset by higher spend on planned major maintenance. In 2018, there was only one planned major outage at one of our non-operating units, while during 2019 there were two planned major outages at the Keephills 1 and Sundance 4 units.

Canadian Coal cash flow for the year ended Dec. 31, 2019, increased by $36 million (excluding the PPA Termination Payments) compared to 2018, mainly due to higher comparable EBITDA and decreased sustaining and productivity capital expenditures.

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

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

Revenue for the year ended Dec. 31, 2018, decreased by $95 million compared to 2017, mainly due to lower production
offset by higher prices. Revenue per MWh of production rose to approximately $63 per MWh in 2018 from $44 per MWh in 2017, which more than offset the increase in carbon compliance costs and resulted in higher gross margin per MWh in 2018.

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

During 2018, we commenced co-firing with natural gas. The combined impact of relatively low Alberta gas prices and lower GHG compliance costs made this economically viable on the merchant plants for a substantial part of the year.

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

Comparable EBITDA for the year ended Dec. 31, 2018, increased $68 million compared to 2017, as a result of the one-time receipt of $157 million for the termination of the Sundance B and C PPAs, partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs.

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

US Coal

Year ended Dec. 31	**2019**	2018	2017
Availability (%)	**74.0**	60.2	66.3
Adjusted availability (%)[1]	**83.5**	84.6	86.2
Contract sales volume (GWh)	**3,329**	3,329	3,609
Merchant sales volume (GWh)	**7,691**	5,704	5,488
Purchased power (GWh)	**(3,865)**	(3,665)	(3,625)
Total production (GWh)	**7,155**	5,368	5,472
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues[2]	**559**	471	427
Fuel and purchased power	**416**	314	293
Comparable gross margin	**143**	157	134
Operations, maintenance and administration	**67**	61	51
Taxes, other than income taxes	**3**	5	4
Comparable EBITDA[2]	**73**	91	79
Deduct:			
Sustaining capital:			
Routine capital	**2**	2	3
Planned major maintenance	**5**	11	29
Total sustaining capital expenditures[3]	**7**	13	32
Productivity capital	**1**	—	3
Total sustaining and productivity capital[3]	**8**	13	35
Payments on lease obligations[3]	**—**	4	3
Decommissioning and restoration costs settled	**11**	11	8
US Coal cash flow	**54**	63	33

(1) Adjusted for dispatch optimization.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line. The contractual arrangement that was accounted for as a finance lease in 2018 and prior periods is not considered a lease under IFRS 16. Accordingly, the costs are reflected in fuel and purchased power and there are no payments on lease obligations from Jan. 1, 2019.

2019
Adjusted availability for the year was down compared to 2018 due to higher forced outages and derates in 2019. Centralia Unit 1 operated with a derate due to blocked precipitator hoppers impacting the first half of 2019. This derate was resolved when the unit was offline during the second quarter of 2019.

Production was up 1,787 GWh in 2019 compared to 2018, due mainly to higher merchant pricing in the first half of 2019 and timing of dispatch optimization. In 2019, both Centralia units remained in service into April due to higher prices in the Pacific Northwest, whereas in 2018, both Centralia units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In 2018, we performed major maintenance on both units during that time.

OM&A costs were $6 million higher in 2019 compared to 2018, mainly due to higher levels of maintenance required to support a 33 per cent increase in production and as a result of higher costs to resolve precipitator blockages.

Comparable EBITDA decreased by $18 million compared to 2018, primarily due to an isolated and extreme pricing event in March. Centralia was unable to commit one of its units to physical production for day-ahead supply due to an unplanned forced outage repair.

Sustaining and productivity capital expenditures for 2019 were $5 million lower than 2018, mainly due to less planned outage work performed in 2019.

US Coal's cash flow for 2019 decreased by $9 million compared to the prior year, mainly due to lower comparable EBITDA, partially offset by lower sustaining and productivity capital spend.

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

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

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

Comparable EBITDA increased by $12 million compared to 2017, primarily due to reduced coal costs and favourable market prices.

Sustaining and productivity capital expenditures for 2018 were $22 million lower than 2017, due to lower planned outages.

US Coal's 2018 cash flow improved by $30 million compared to 2017, mainly due to stronger comparable EBITDA and lower sustaining and productivity capital spend.

Canadian Gas

Year ended Dec. 31	2019	2018	2017
Availability (%)	**94.8**	93.3	91.6
Contract production (GWh)	**1,655**	1,620	1,504
Merchant production (GWh)[1]	**170**	93	244
Total production (GWh)	**1,825**	1,713	1,748
Gross installed capacity (MW)[2]	**945**	945	952
Revenues[3]	**238**	407	423
Fuel and purchased power	**74**	99	113
Comparable gross margin	**164**	308	310
Operations, maintenance and administration	**44**	48	53
Taxes, other than income taxes	**1**	1	1
Net other operating income	**(1)**	**—**	**—**
Comparable EBITDA[3]	**120**	259	256
Deduct:			
Sustaining capital:			
Routine capital	**10**	4	8
Planned major maintenance	**8**	16	22
Total sustaining capital expenditures	**18**	20	30
Productivity capital	**—**	2	2
Total sustaining and productivity capital	**18**	22	32
Provisions and other	**—**	9	3
Decommissioning and restoration costs settled	**3**	—	—
Canadian Gas cash flow	**99**	228	221

(1) Includes purchased power, which is used for dispatch optimization, when economical.
(2) Excludes capacity of Mississauga, which was mothballed in early 2017. All years include production capacity for the Fort Saskatchewan facility, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor Energy. We continue to own a portion of the facility and have included our portion as a part of gross capacity measures.
(3) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

2019

Availability for the year ended Dec. 31, 2019, increased compared to 2018, primarily due to lower planned outages at Fort Saskatchewan and Sarnia.

Production for the year increased by 112 GWh compared to 2018, mainly due to higher customer and market demand as well as lower planned outages, which was partially offset by higher unplanned outages.

Comparable EBITDA for 2019 decreased by $139 million compared to 2018, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease. Comparable EBITDA for the year ended Dec. 31, 2019, includes nil (2018 - $105 million) and $20 million (2018 - $57 million) from the Mississauga and Poplar Creek contracts, respectively. Additionally, comparable EBITDA benefited from lower OM&A compared to the prior year as a result of reduced overhead and operating costs.

Sustaining capital totalled $18 million in 2019, a decrease of $2 million due to lower planned outage costs, partially offset by the timing of capital spares purchases for Sarnia.

Cash flow at Canadian Gas decreased by $129 million for the year ended Dec. 31, 2019, compared to the prior year mainly due to lower comparable EBITDA.

2018

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

Production for the year decreased by 35 GWh compared to 2017, as lower market demand at Sarnia was partially offset by higher production at the Fort Saskatchewan, Ottawa and Windsor facilities in 2018.

Comparable EBITDA for 2018 increased by $3 million compared to 2017, mainly due to the positive impact from the Mississauga recontracting, higher realized pricing at Sarnia and cost reduction initiatives, partially offset by the retroactive contract indexation dispute settlement with the OEFC in 2017 ($34 million). The Mississauga, Ottawa, Windsor and our 60 per cent share of Fort Saskatchewan generating facilities are owned through our 50.01 per cent interest in TA Cogen. The Mississauga recontracting ended in December 2018 and was not renewed.

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

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

Australian Gas

Year ended Dec. 31	2019	2018	2017
Availability (%)	**90.6**	94.0	93.4
Contract production (GWh)	**1,832**	1,814	1,803
Gross installed capacity (MW)[1]	**450**	450	450
Revenues	**160**	165	180
Fuel and purchased power	**5**	4	12
Comparable gross margin	**155**	161	168
Operations, maintenance and administration	**37**	37	31
Comparable EBITDA	**118**	124	137
Deduct:			
Sustaining capital:			
Routine capital	**2**	2	9
Planned major maintenance	**3**	—	1
Total sustaining capital expenditures	**5**	2	10
Productivity capital	**1**	—	—
Total sustaining and productivity capital	**6**	2	10
Other	**—**	(14)	—
Australian Gas cash flow	**112**	136	127

(1) In 2017, Fortescue Metals Group Ltd. ("FMG") repurchased the Solomon facility and therefore it was removed from 2017 capacity, which was offset by adding capacity for the South Hedland facility, which achieved commercial operations on July 28, 2017.

2019

Availability for the year ended Dec. 31, 2019, decreased compared to 2018, mainly due to unplanned outages.

Production for 2019 was comparable to 2018. Due to the nature of our contracts, changes in production do not have a significant financial impact as our contracts are structured as capacity payments with customer supplied fuel or a passthrough of fuel costs.

Comparable EBITDA for the year ended Dec. 31, 2019, decreased by $6 million compared to 2018, due to the weakening of the Australian dollar and ongoing legal costs associated with our disputes with FMG.

Sustaining and productivity capital for 2019 increased by $4 million compared to 2018, mainly due to planned major maintenance at our Southern Cross facility.

Cash flow at Australian Gas decreased by $24 million in 2019, mainly due to lower comparable EBITDA as well as higher sustaining capital expenditures. In addition, 2018 cash flow included the collection of a long-term receivable.

2018

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

Comparable EBITDA for the year decreased by $13 million compared to 2017 mainly due to FMG's repurchase of the Solomon facility, higher OM&A costs due to the addition of the South Hedland facility and ongoing legal costs associated with our disputes with FMG, which were partially offset by higher EBITDA from the South Hedland facility. Refer to the Other Consolidated Analysis section of this MD&A for further details.

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

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

Wind and Solar

Year ended Dec. 31	2019	2018	2017
Availability (%)	**95.0**	95.4	95.8
Contract production (GWh)	**2,395**	2,363	2,362
Merchant production (GWh)	**960**	1,005	1,098
Total production (GWh)	**3,355**	3,368	3,460
Gross installed capacity (MW)[1]	**1,495**	1,382	1,363
Revenues[2]	**295**	302	287
Fuel and purchased power	**16**	17	17
Comparable gross margin	**279**	285	270
Operations, maintenance and administration	**50**	50	48
Taxes, other than income taxes	**8**	8	8
Net other operating income[3]	**(10)**	(6)	—
Comparable EBITDA[2]	**231**	233	214
Deduct:			
Sustaining capital:			
Routine capital	**2**	5	1
Planned major maintenance	**11**	8	10
Total sustaining capital expenditures	**13**	13	11
Productivity capital	**—**	2	2
Total sustaining and productivity capital	**13**	15	13
Payments on lease obligations[4]	**1**	—	—
Decommissioning and restoration costs settled	**1**	1	—
Other[3]	**10**	6	—
Wind and Solar cash flow	**206**	211	201

(1) The 2019 installed capacity includes the addition of Big Level and Antrim in late December, partially offset by the reduction of wind turbines due to tower fires at Wyoming Wind and Summerview.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) Relates to insurance proceeds included in net other operating income.
(4) On implementation of IFRS 16 in 2019, we have included principal payments on lease obligations as a separate line.

2019

Availability and production for the year ended Dec. 31, 2019, was comparable to 2018, which was in line with our expectations. The Big Level and Antrim wind farms had minimal impact on 2019 availability and production due to their commercial operation occurring in late December.

Comparable EBITDA for 2019 was consistent with 2018. Higher insurance proceeds from tower fires at Wyoming Wind and Summerview were partially offset by a reduction in revenues due to the scheduled expiration of production-based incentives for three wind facilities.

Wind and Solar's cash flow decreased by $5 million for the year ended Dec. 31, 2019, compared to the prior year, mainly due to lower revenue.

2018

Availability for the year ended Dec. 31, 2018, was comparable to 2017, which was in line with our expectations.

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

Comparable EBITDA for 2018 was higher than 2017, due to higher merchant prices in Alberta and insurance proceeds from the tower fire at the Wyoming Wind farm, which was partially offset by the unfavourable impact of lower wind resources.

Wind and Solar's cash flow improved by $10 million for the year ended Dec. 31, 2018, compared to the prior year, due mainly to higher comparable EBITDA, partially offset by the adjustment to remove the insurance proceeds from cash flow.

Hydro

Year ended Dec. 31	**2019**	2018	2017
Production			
Energy contracted			
Alberta Hydro PPA assets (GWh)[1]	**1,653**	1,519	1,530
Other hydro energy (GWh)[1]	**331**	306	336
Energy merchant			
Other hydro energy (GWh)	**61**	81	82
Total energy production (GWh)	**2,045**	1,906	1,948
Ancillary service volumes (GWh)[2]	**2,978**	3,265	3,044
Gross installed capacity (MW)	**926**	926	926
Revenues			
Alberta Hydro PPA assets energy	**101**	90	36
Alberta Hydro PPA assets ancillary	**90**	104	36
Capacity payments received under Alberta Hydro PPA[3]	**57**	56	54
Other revenue[4]	**44**	41	43
Total gross revenues	**292**	291	169
Net payment relating to Alberta Hydro PPA[5]	**(136)**	(135)	(48)
Revenues	**156**	156	121
Fuel and purchased power	**7**	6	6
Comparable gross margin	**149**	150	115
Operations, maintenance and administration	**36**	38	37
Taxes, other than income taxes	**3**	3	3
Comparable EBITDA	**110**	109	75
Deduct:			
Sustaining capital:			
Routine capital	**7**	4	8
Planned major maintenance	**7**	8	5
Total sustaining capital expenditures	**14**	12	13
Productivity capital	**1**	1	1
Total sustaining and productivity capital	**15**	13	14
Decommissioning and restoration costs settled	**2**	—	—
Hydro cash flow	**93**	96	61

(1) Alberta Hydro PPA assets include 13 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPAs.
(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer. The PPA expires on Dec. 31, 2020.
(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.
(5) The net payment relating to the Alberta Hydro PPA represents the Corporation's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA which expires on Dec. 31, 2020.

2019
Production for 2019 increased by 139 GWh over 2018, primarily due to higher water resources.

Total gross revenues were comparable to 2018, as the Hydro business optimizes its revenue through a combination of energy sales and Ancillary Services, which allows us to maintain consistent revenues year-over-year.

Comparable EBITDA for 2019 increased by $1 million compared to 2018, as we were able to reduce OM&A due to cost- saving initiatives, while absorbing the $1.5 million Brookfield Hydro Fee. Refer to the Corporate Strategy and Significant and Subsequent Events section of this MD&A for further details.

Hydro's cash flow decreased by $3 million for 2019 compared to 2018, mainly due to higher capital expenditures and decommissioning costs related to transmission assets.

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

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

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

Energy Marketing

Year ended Dec. 31	**2019**	2018	2017
Revenues and comparable gross margin[(1)]	**119**	67	57
Operations, maintenance and administration	**30**	24	24
Comparable EBITDA[(1)]	**89**	43	33
Deduct:			
Provisions and other	**(16)**	10	(6)
Energy Marketing cash flow	**105**	33	39

(1) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

2019
Comparable EBITDA for 2019 increased by $46 million compared to 2018 results, due to strong results from all Marketing segments, with particularly strong performance from US Western and Eastern markets due to continued high levels of volatility. OM&A increased due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short-term arbitrage opportunities in the markets in which we trade without materially changing the risk profile of the business unit.

Energy Marketing's cash flows for 2019 increased by $72 million compared to 2018, mainly due to higher Comparable EBITDA and other cash settlements.

2018
Comparable EBITDA for 2018, excluding unrealized mark-to-market gains or losses, was $10 million higher than 2017 due to strong results from most marketing segments, with particularly strong performance from the US Western market and year-over-year improvements in natural gas markets.

Energy Marketing's cash flows for 2018 decreased by $6 million compared to 2017, mainly due to the settlement of trading positions adversely affected by cold weather in the first quarter.

Corporate

Year ended Dec. 31	2019	2018	2017
Operations, maintenance, and administration	**73**	86	84
Taxes, other than income taxes	**1**	1	1
Net other operating loss	**2**	—	—
Comparable EBITDA	**(76)**	(87)	(85)
Deduct:			
Sustaining capital:			
Routine capital	**12**	16	18
Total sustaining capital expenditures	**12**	16	18
Productivity capital	**—**	4	4
Total sustaining and productivity capital expenditures	**12**	20	22
Provisions	**—**	—	1
Payments on lease obligations[1]	**4**	—	—
Corporate cash flow	**(92)**	(107)	(108)

(1) On implementation of IFRS 16 in 2019, we have included principal payments on lease obligations as a separate line.

2019

Our Corporate overhead costs in 2019 were $76 million, a decrease of $11 million compared to $87 million in 2018, primarily due to cost-efficiency initiatives and payments on lease obligations. In addition, we realized a net gain of $13 million from the total return swap on our share-based payment plans, which was mostly offset by higher legal fees. A portion of the settlement cost of our share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter. Corporate cash flow also benefited from lower sustaining and productivity capital spend due to higher spend in 2018 on automation and new information technology solutions implemented in prior years, which helped contribute to the cost efficiencies realized in 2019.

2018

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

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2019	2018
Revenues	**609**	622
Fuel, carbon compliance and purchased power	**286**	336
Operations, maintenance and administration	**127**	139
Net earnings (loss) attributable to common shareholders	**66**	(122)
Cash flow from operating activities	**181**	132
Comparable EBITDA[1]	**243**	265
FFO[1]	**189**	217
FCF[1]	**121**	98
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.24**	(0.43)
FFO per share[1]	**0.67**	0.76
FCF per share[1]	**0.43**	0.34
Dividends declared per common share[3]	**0.04**	0.08
Dividends declared per preferred share[4]	**0.26**	0.52

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) Dividends declared vary year over year due to timing of dividend declarations.
(4) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.

Financial Highlights

We delivered strong results in the fourth quarter with FCF of $121 million, compared to $98 million last year, mainly due to lower sustaining capital expenditures and distributions paid to subsidiaries, partially offset by lower comparable EBITDA. FFO was $189 million, which was $28 million lower than the fourth quarter of 2018, also mainly due to lower comparable EBITDA.

Net earnings attributable to common shareholders in the fourth quarter of 2019 was $66 million ($0.24 net earnings per share) compared to a net loss of $122 million ($0.43 net loss per share) in the same period of 2018, an improvement of $188 million. This was driven partially by the Keephills 3 and Genesee 3 swap with Capital Power where we recognized a gain on termination of the coal rights contract of $88 million and a gain on the sale of Genesee 3 of $77 million (refer to the Highlights and Significant and Subsequent Events sections of this MD&A for further details). In addition, the fourth quarter showed the impact of cost-saving initiatives in OM&A, fuel, carbon compliance and purchased power costs as well as lower interest expense, partially offset by higher impairment charges, losses on sale of PP&E and higher income tax expense.

Segmented Cash Flow Generated by the Business and Operational Performance

Segmented cash flow 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 flow available to pay our interest and cash taxes, distributions to our non-controlling partners, dividends to our preferred shareholders and to grow the business, pay down debt and return capital to our shareholders.

Segmented cash flow and operational performance for the business for the three months ended Dec. 31, 2019 and 2018 is as follows:

Three months ended Dec. 31	**2019**	2018
Availability (%)[1]	**91.6**	91.5
Production (GWh)[1]	**8,153**	8,276
Segmented cash flow[2]		
Canadian Coal	**37**	16
US Coal	**25**	21
Canadian Gas	**22**	59
Australian Gas	**25**	35
Wind and Solar	**72**	74
Hydro	**13**	11
Generation segmented cash flow	**194**	216
Energy Marketing	**31**	10
Corporate	**(29)**	(34)
Total segmented cash flow	**196**	192

(1) Availability and production includes all generating assets under generation operations that we operate and finance leases and excludes hydro assets and equity investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.
(2) This is not defined and has no standardized meaning under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.

Availability for the three months ended Dec. 31, 2019, was comparable with the same period in 2018. Lower production for the three months ended Dec. 31, 2019, compared to the same period in 2018 is primarily due to paid curtailments at Canadian Coal and lower wind resources, partially offset by higher production at US Coal.

Comparable cash flow generated by the business totalled $196 million in the fourth quarter, an increase of $4 million compared with last year's performance. Increased cash flow is largely due to the strong performance at Canadian Coal and Energy Marketing, partially offset by lower cash flow at Canadian Gas as a result of the termination of the Mississauga contract as well as lower scheduled payments at Poplar Creek. In addition, 2018 comparable cash flow benefited from the settlement of a long-term receivable in Australian Gas.

Discussion of Consolidated Financial Results for the Fourth Quarter

Comparable EBITDA

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

Three months ended Dec. 31	**2019**	2018
Net earnings (loss) attributable to common shareholders	**66**	(122)
Net earnings attributable to non-controlling interests	**27**	43
Preferred share dividends	**10**	20
Net earnings (loss)	**103**	(59)
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**40**	(16)
Gain on sale of assets and other	**(64)**	—
Foreign exchange (gain) loss	**(3)**	—
Net interest expense	**18**	50
Depreciation and amortization	**154**	152
Comparable reclassifications		
Decrease in finance lease receivables	**5**	15
Mine depreciation included in fuel cost	**31**	37
Australian interest income	**1**	1
Unrealized mark-to-market (gains) losses	**(1)**	32
Adjustments to earnings to arrive at comparable EBITDA		
Impacts to revenue associated with certain de-designated and economic hedges	**—**	—
Impacts associated with Mississauga recontracting[1]	**—**	30
Gain on termination of Keephills 3 coal rights contract	**(88)**	—
Asset impairment charge[2]	**47**	23
Comparable EBITDA	**243**	265

(1) Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2019, are as follows: revenue nil (2018 - $30 million).
(2) Asset impairment charges for the three months ended Dec. 31, 2019, include $32 million increase for the decommissioning and restoration liability at the Centralia mine and $15 million for trucks held for sale and written down to net realizable value (2018 - includes the write-off of project development costs of $23 million).

A summary of our comparable EBITDA by segment for the three months ended Dec. 31, 2019 and 2018 is as follows:

Three months ended Dec. 31	**2019**	2018
Comparable EBITDA		
Canadian Coal	**55**	48
US Coal	**29**	24
Canadian Gas	**29**	74
Australian Gas	**28**	32
Wind and Solar	**80**	82
Hydro	**18**	17
Energy Marketing	**26**	16
Corporate	**(22)**	(28)
Total Comparable EBITDA	**243**	265

Comparable EBITDA decreased by $22 million for the fourth quarter 2019, compared to 2018, primarily as a result of:

- Our Canadian Coal results were up $7 million mainly due to lower OM&A in 2019.
- US Coal results were up $5 million primarily due to lower fuel and purchased power costs and increased volumes.
- Our Canadian Gas business was down $45 million mainly due to the Mississauga contract ending in 2018 and lower scheduled payments from Poplar Creek.
- Australian Gas was down $4 million, mainly due to the weakening of the Australian dollar and slightly higher legal costs.
- Wind and Solar results were down $2 million period-over-period mainly due to lower revenues due to the scheduled expirations of production-based incentives for wind facilities.
- Hydro results were $1 million higher and therefore fairly consistent, which was in line with our expectations.
- Energy Marketing's comparable EBITDA was up $10 million, mainly due to continued high levels of volatility in the market.
- Corporate costs decreased by $6 million in the fourth quarter mainly due to the realized net gain from the total return swap on our share-based payment plans and cost-saving efficiencies.

Funds from Operations and Free Cash Flow

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

The table below reconciles our cash flow from operating activities to our FFO and FCF for the three months ended Dec. 31, 2019 and 2018:

Three months ended Dec. 31	**2019**	2018
Cash flow from operating activities	**181**	132
Change in non-cash operating working capital balances	**1**	69
Cash flow from operations before changes in working capital	**182**	201
Adjustments		
Decrease in finance lease receivable	**5**	15
Other	**2**	1
FFO	**189**	217
Deduct:		
Sustaining capital	**(30)**	(52)
Productivity capital	**(2)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(22)**	(43)
Payments on lease obligations[(1)]	**(5)**	(4)
Other	**1**	(1)
FCF	**121**	98
Weighted average number of common shares outstanding in the period	**280**	286
FFO per share	**0.67**	0.76
FCF per share	**0.43**	0.34

(1) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

The table below provides a reconciliation of our comparable EBITDA to our FFO and FCF for the three months ended Dec. 31, 2019 and 2018:

Three months ended Dec. 31	**2019**	2018
Comparable EBITDA	**243**	265
Provisions	**(1)**	(5)
Interest expense	**(41)**	(40)
Current income tax expense	**(7)**	(10)
Realized foreign exchange gain (loss)	**1**	1
Decommissioning and restoration costs settled	**(10)**	(8)
Other non-cash items	**4**	14
FFO	**189**	217
Deduct:		
Sustaining capital	**(30)**	(52)
Productivity capital	**(2)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(22)**	(43)
Payments on lease obligations	**(5)**	(4)
Other	1	(1)
Comparable FCF	**121**	98
Weighted average number of common shares outstanding in the period	**280**	286
Comparable FFO per share	**0.67**	0.76
Comparable FCF per share	**0.43**	0.34

Selected Quarterly Information

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

	Q1 2019	Q2 2019	Q3 2019	**Q4 2019**
Revenues	648	497	593	**609**
Comparable EBITDA[1]	221	215	305	**243**
FFO	169	155	244	**189**
Net earnings (loss) attributable to common shareholders	(65)	—	51	**66**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.23)	—	0.18	**0.24**

	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	588	446	593	622
Comparable EBITDA[1]	396	248	252	265
FFO	318	188	204	217
Net earnings (loss) attributable to common shareholders	65	(105)	(86)	(122)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	0.23	(0.36)	(0.30)	(0.43)

(1) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(2) Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.

Reported net earnings, comparable EBITDA and FFO are generally higher in the first and fourth quarters due to higher demand associated with the cold winter months 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:

- Gains relating to the Keephills 3 and Genesee 3 swap in the fourth quarter of 2019;
- Effects of impairment charges and reversals during the third and fourth quarters of 2019 and impairment charges during the second, third and fourth quarters of 2018;
- Effects of changes in useful lives of certain assets during the third quarter of 2019;
- Change in income tax rates in Alberta in the second quarter of 2019;
- Lower scheduled payments commencing in January 2019 from the Poplar Creek finance lease; and
- Recognition of the $157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018 and $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies. We maintained a strong and flexible financial position in 2019.

Funds from Operations before Interest to Adjusted Interest Coverage

For the year ended Dec. 31	**2019**	2018	2017
FFO[(1)]	**757**	927	804
Less: PPA Termination Payments	**(56)**	(157)	—
Add: Interest on debt, exchangeable securities and leases, net of interest income and capitalized interest	**166**	174	205
FFO before interest	**867**	944	1,009
Interest on debt, exchangeable securities and leases, net of interest income	**172**	176	214
Add: 50 per cent of dividends paid on preferred shares	**20**	20	20
Adjusted interest	**192**	196	234
FFO before interest to adjusted interest coverage (times)	**4.5**	4.8	4.3

(1) See the Discussion of Consolidated Financial Results section in this MD&A for reconciliation of cash flow from operating activities to FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.

Our target for FFO before interest to adjusted interest coverage is four to five times. While all periods are within our target range, the ratio decreased slightly in 2019 compared to 2018, mainly due to lower FFO before interest.

Adjusted FFO to Adjusted Net Debt

As at Dec. 31	2019	2018	2017
FFO[1, 2]	**757**	927	804
Less: PPA Termination Payments[1]	**(56)**	(157)	—
Less: 50 per cent of dividends paid on preferred shares[1]	**(20)**	(20)	(20)
Adjusted FFO[1]	**681**	750	784
Period-end long-term debt[3]	**3,212**	3,267	3,707
Exchangeable securities	**326**	—	—
Less: Cash and cash equivalents	**(411)**	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	(27)	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt[4]	**(7)**	(10)	(30)
Adjusted net debt	**3,581**	3,612	3,834
Adjusted FFO to adjusted net debt (%)	**19.0**	20.8	20.4

(1) Last 12 months.
(2) Refer to the Discussion of Consolidated Financial Results section of this MD&A for the reconciliation of cash flow from operating activities to FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.
(3) Includes lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.

Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent. Our adjusted FFO to adjusted net debt declined due to lower adjusted FFO compared with 2018, partially offset by lower adjusted net debt. We reached the low end of our target range of 20 to 25 per cent in 2017 and 2018.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	2019	2018	2017
Period-end long-term debt[1]	**3,212**	3,267	3,707
Exchangeable securities	**326**	—	—
Less: Cash and cash equivalents	**(411)**	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	(27)	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt[2]	**(7)**	(10)	(30)
Adjusted net debt	**3,581**	3,612	3,834
Comparable EBITDA[3,4]	**984**	1,161	1,030
Less: PPA Termination Payments[3,4]	**(56)**	(157)	—
Adjusted comparable EBITDA[3,4]	**928**	1,004	1,030
Adjusted net debt to adjusted comparable EBITDA (times)	**3.9**	3.6	3.7

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.
(3) Last 12 months.
(4) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio increased compared to 2018, mainly due to the decrease in adjusted comparable EBITDA during the year, after adjusting for the PPA Termination Payments.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage excluding the portion of TransAlta Renewables and TA Cogen that are not owned by TransAlta. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at Dec. 31	2019	2018	2017
Period-end long-term debt[1]	**3,212**	3,267	3,707
Exchangeable securities	**326**	—	—
Less: Cash and cash equivalents	**(411)**	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	(27)	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt[2]	**(7)**	(10)	(30)
Less: TransAlta Renewables long-term debt	**(961)**	(932)	(1,043)
Less: US tax equity financing[3]	**(145)**	(28)	(31)
Deconsolidated net debt	**2,475**	2,652	2,760
Comparable EBITDA[4, 5]	**984**	1,161	1,030
Less: PPA Termination Payments[4]	**(56)**	(157)	—
Less: TransAlta Renewables comparable EBITDA[4]	**(438)**	(430)	(424)
Less: TA Cogen comparable EBITDA[4]	**(80)**	(181)	(182)
Add: Dividend from TransAlta Renewables[4]	**151**	151	140
Add: Dividend from TA Cogen[4]	**37**	86	86
Deconsolidated comparable EBITDA [4, 5]	**598**	630	650
Deconsolidated net debt to deconsolidated comparable EBITDA[4, 5] (times)	**4.1**	4.2	4.2

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.
(3) Relates to assets where TransAlta Renewables has economic interests.
(4) Last 12 months.
(5) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

Our target for deconsolidated net debt to deconsolidated comparable EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio improved slightly compared with 2018, as lower deconsolidated net debt was partially offset by lower deconsolidated comparable EBITDA.

Deconsolidated FFO

During the third quarter of 2019, the Corporation implemented a new dividend policy that aims to return 10 to 15 per cent of TransAlta's deconsolidated FFO to shareholders as it aligns shareholder returns to the assets held directly at TransAlta. This metric is not defined and has no standardized meaning under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the IFRS Measures and Non-IFRS Measures section of this MD&A for further details. Deconsolidated FFO for the years ended Dec. 31 is detailed below:

			2019			2018			2017
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**849**	**331**		820	385		626	290	
Change in non-cash operating working capital balances	**(121)**	**(23)**		44	5		114	17	
Cash flow from operations before changes in working capital	**728**	**308**		864	390		740	307	
Adjustments:									
Decrease in finance lease receivable	**24**	**—**		59	—		59	—	
Finance and interest income - economic interests	**—**	**(76)**		—	(171)		—	(86)	
Adjusted FFO - economic interests	**—**	**146**		—	162		—	137	
Other	**5**	**—**		4	—		5	—	
FFO	**757**	**378**	**379**	927	381	546	804	358	446
Dividend from TransAlta Renewables			**151**			151			140
Distributions to TA Cogen's Partner			**(37)**			(86)			(86)
Less: PPA Termination Payments			**(56)**			(157)			—
Deconsolidated TransAlta FFO			**437**			454			500

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2018, to Dec. 31, 2019:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	322	Timing of receipts and payments and cash received from the issuance of the exchangeable securities
Restricted cash	(34)	Kent Hills restricted cash was released in July 2019 ($31 million) and the restricted cash related to the TransAlta OCP bonds was paid in Feb. 2019 ($35 million), partially offset by the Off Coal Agreement payments received ($17 million) in Aug. 2019 that will be restricted until the TransAlta OCP bonds are paid in Feb. 2020 as well as new restricted cash related to the Big Level tax equity financing ($15 million)
Trade and other receivables	(294)	Timing of customer receipts
Finance lease receivables (long-term)	(15)	Principal repayments
PP&E	43	Depreciation for the period ($630 million), net disposals mainly related to the Genesee 3 sale and decommissioning of Mississauga ($265 million), unfavourable changes in foreign exchange rates ($58 million), and adjustments on implementation of IFRS 16 ($62 million), partially offset by additions ($522 million), acquisitions mainly related to Keephills 3 and Antrim ($439 million) and revisions to decommissioning and restoration costs ($23 million)
Right of use assets	146	Transfers from PP&E, intangible assets and other assets ($38 million) and new right of use assets recognized under IFRS 16 ($47 million) (see Accounting Changes section for further details), additions related to the Pioneer Pipeline ($45 million) as well as land lease and other additions ($36 million), partially offset by depreciation ($18 million)
Intangible assets	(55)	Amortization ($50 million) and net disposals mainly related to the Genesee 3 sale ($28 million), partially offset by additions ($14 million) and acquisitions mainly related to Antrim ($16 million)
Other assets	(36)	Pioneer Pipeline project development costs were reclassified to PP&E ($15 million) and the write-off of projects that will no longer proceed ($18 million)
Other	3	
Total change in assets	**80**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(83)	Timing of payments and accruals
Dividends payable	(21)	Timing of the declaration of common and preferred share dividends
Credit facilities, long-term debt and lease obligations (including current portion)	(55)	Repayments on the credit facilities ($119 million), repayments of long-term debt ($96 million) favourable changes in foreign exchange ($42 million), reduction due to the tax shield on tax equity financing ($35 million), derecognition of a lease obligation on implementation of IFRS 16 ($32 million) and repayments of lease obligations ($21 million) were partially offset by the issuance of the tax equity financing ($166 million) and new lease liabilities ($133 million)
Exchangeable securities	326	Issuance of exchangeable debentures in May 2019 to Brookfield. See the Significant and Subsequent Events section of this MD&A for further details
Decommissioning and other provisions (current and long-term)	90	Change in estimate for the Centralia mine ($141 million), accretion ($23 million), acquisition of liabilities ($19 million), revisions to discount rates ($16 million) and liabilities incurred ($14 million), partially offset by liabilities settled ($42 million), lower estimated cash flows at other locations ($38 million), disposition of liabilities ($32 million) and favourable changes in foreign exchange rates ($7 million). See the Accounting Changes section of this MD&A for further details
Risk management liabilities (current and long-term)	(21)	Contract settlements, partially offset by favourable market prices
Contract liabilities	(73)	The coal rights contract was terminated as part of the Keephills 3 and Genesee 3 swap ($88 million), partially offset by contract liabilities moved from defined benefit obligation and other long-term liabilities as they are no longer considered leases on the adoption of IFRS 16 ($15 million) (see the Significant and Subsequent Events and Accounting Changes sections of this MD&A for further details)
Defined benefit obligation and other long-term liabilities	14	Actuarial losses before tax ($33 million) partially offset by liabilities moved to contract liabilities ($15 million)
Deferred income tax liabilities	(29)	Decrease in taxable temporary differences mainly due to the Alberta tax rate reduction (see the Other Consolidated Analysis section for further details)
Equity attributable to shareholders	(36)	Net other comprehensive loss ($28 million), common share dividends ($34 million), preferred share dividends ($30 million), shares purchased under NCIB ($68 million), partially offset by net earnings ($82 million), the effect of share-based payment plans ($33 million) and changes in non-controlling interests in TransAlta Renewables ($6 million)
Non-controlling interests	(36)	Distributions paid and payable ($135 million) and intercompany fair value through other comprehensive income investments ($17 million), partially offset by net earnings ($94 million), changes in non-controlling interests in TransAlta Renewables from share issuances under the dividend reinvestment plan ($22 million)
Other	4	
Total change in liabilities and equity	**80**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2018, and Dec. 31, 2017, compared to the year ended Dec. 31, 2019:

Year ended Dec. 31	**2019**	2018	**Increase/ (decrease)**	**Primary factors explaining change**
Cash and cash equivalents, beginning of year	**89**	314	(225)	
Provided by (used in):				
Operating activities	**849**	820	29	Favourable changes in non-cash working capital ($165 million), partially offset by lower cash flow from operations before changes in working capital ($136 million) mainly due to the net impact of the PPA Termination Payments
Investing activities	**(512)**	(394)	(118)	Higher additions to PP&E mainly as a result of the construction of Big Level and Antrim ($140 million), higher acquisitions mainly due to the Kineticor acquisition ($87 million), investment in the Pioneer Pipeline ($83 million), lower scheduled payments from finance lease receivables ($35 million), partially offset by a decrease in restricted cash ($69 million), a favourable change in non-cash investing working capital ($128 million) and higher cash proceeds on sale of PP&E ($11 million)
Financing activities	**(14)**	(651)	637	Lower repayments of long-term debt ($1,083 million), issuance of the exchangeable securities ($350 million), lower proceeds on issuance of debt ($179 million) and lower distributions paid to subsidiaries' non-controlling interests ($59 million), partially offset by higher net repayments under credit facilities ($431 million), proceeds received in 2018 for the sale of TransAlta Renewables common shares ($144 million), lower realized gains on financial instruments ($48 million) and higher share buybacks under NCIB ($45 million)
Translation of foreign currency cash	**(1)**	—	(1)	
Cash and cash equivalents, end of year	**411**	89	322	

Year ended Dec. 31	2018	2017	**Increase/ (decrease)**	**Primary factors explaining change**
Cash and cash equivalents, beginning of year	314	305	9	
Provided by (used in):				
Operating activities	820	626	194	Higher cash flow from operations before working capital ($124 million) and a favourable change in non-cash working capital ($70 million)
Investing activities	(394)	87	(481)	Lower proceeds on sale of the Wintering Hills wind facility and Solomon ($476 million), unfavourable change in non-cash investing capital ($153 million) and the acquisition of Big Level and Antrim ($30 million), partially offset by lower additions to PP&E ($61 million), lower tax expense relating to investing activities ($56 million), lower additions to intangibles ($31 million) and the lower issuance of loan receivable ($39 million)
Financing activities	(651)	(703)	52	Increase in borrowings under credit facilities ($286 million), higher issuance of long-term debt ($85 million) and higher proceeds on the sale of non-controlling interest in a subsidiary ($144 million), partially offset by higher repayments of long-term debt ($365 million), lower realized gains on financial instruments ($58 million) and repurchase of common shares ($23 million)
Translation of foreign currency cash	—	(1)	1	
Cash and cash equivalents, end of year	89	314	(225)	

Financial Capital

The Corporation is focused on strengthening our financial position and cash flow coverage ratios to ensure a strong balance sheet is maintained and sufficient financial capital is available. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows our commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles.

In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised their rating outlook to stable from positive. During 2019, Fitch Ratings lowered the Corporation's Unsecured Debt rating and Issuer Rating to BB+ with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's lowered the Corporation's Unsecured Debt rating and Issuer Rating to BB+ with a stable outlook. Risks associated with our credit ratings are discussed in the Governance and Risk Management section of this MD&A.

Capital Structure

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

As at Dec. 31	**2019**		2018		2017	
	$	**%**	$	**%**	**$**	**%**
TransAlta Corporation						
Recourse debt - CAD debentures	**647**	**9**	647	9	1,046	13
Recourse debt - US senior notes	**905**	**13**	943	13	1,499	19
Exchangeable securities	**326**	**5**	—	—	—	—
Credit facilities	**—**	**—**	174	2	—	—
Other	**9**	**—**	11	—	13	—
Less: cash and cash equivalents	**(348)**	**(5)**	(16)	—	(294)	(4)
Less: principal portion of restricted cash on TransAlta OCP	**(10)**	**—**	(27)	—	—	—
Less: fair value asset of economic hedging instruments on debt[1)]	**(7)**	**—**	(10)	—	(30)	—
Net recourse debt, excluding US tax equity financing	**1,522**	**22**	1,722	24	2,234	28
US tax equity financing	**145**	**2**	28	—	31	—
Non-recourse debt	**426**	**6**	469	6	208	3
Lease obligations	**119**	**2**	63	1	69	1
Total net debt - TransAlta Corporation	**2,212**	**32**	2,282	31	2,542	32
TransAlta Renewables						
Credit facility	**220**	**3**	165	2	27	—
Less: cash and cash equivalents	**(63)**	**(1)**	(73)	(1)	(20)	—
Net recourse debt	**157**	**2**	92	1	7	—
Non-recourse debt	**718**	**10**	767	11	814	11
Lease obligations	**23**	**—**	—	—	—	—
Total net debt - TransAlta Renewables	**898**	**12**	859	12	821	11
Total consolidated net debt	**3,110**	**44**	3,141	43	3,363	43
Non-controlling interests	**1,101**	**15**	1,137	16	1,059	14
Equity attributable to shareholders						
Common shares	**2,978**	**42**	3,059	42	3,094	40
Preferred shares	**942**	**13**	942	13	942	12
Contributed surplus, deficit and accumulated other comprehensive income	**(959)**	**(14)**	(1,004)	(14)	(710)	(9)
Total capital	**7,172**	**100**	7,275	100	7,748	100

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges.

We continued strengthening our financial position during 2019 and have reduced our total consolidated net debt by $253 million since the end of 2017. Our financing strategy includes replacing our senior recourse debt with asset-level financing, including tax equity. Net recourse debt at TransAlta, excluding tax equity financing, declined by $712 million from $2,234 million in 2017 to $1,522 million in 2019. We have enhanced shareholder value by:

2019

- Obtaining US$126 million in tax equity financing to fund the Big Level and Antrim wind facilities;
- Entering into a strategic investment with Brookfield whereby Brookfield agreed to invest $750 million in the Corporation. On May 1, 2019, we received the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039, which are exchangeable by Brookfield into an equity ownership interest in our Alberta Hydro Assets in the future. The remaining $400 million will be invested in Oct. 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met;
- Purchasing and cancelling 7,716,300 common shares at an average price of $8.80 per share through our NCIB program, for a total cost of $68 million;

2018

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

2017

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

Between 2020 and 2022, we have approximately $1,217 million of debt maturing, comprised of approximately $920 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022.

The weakening of the US dollar has decreased our long-term debt balances by $42 million as at Dec. 31, 2019. 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	**2019**	2018
Effects of foreign exchange on carrying amounts of US operations (net investment hedge) and finance lease receivable	**(21)**	42
Foreign currency cash flow hedges on debt	**(9)**	11
Economic hedges and other	**(9)**	21
Unhedged	**(3)**	2
Total	**(42)**	76

Our credit facilities provide us with significant liquidity. At Dec. 31, 2019, we had $2.2 billion (2018 - $2.0 billion) of committed credit facilities, of which $1.3 billion (2018 - $0.9 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2019, the $0.9 billion (2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $0.2 billion (2018 - $0.3 billion) and letters of credit of $0.7 billion (2018 - $0.7 billion). These facilities are comprised of a $1.3 billion committed syndicated bank facility expiring in 2023, TransAlta Renewables $700 million committed syndicated bank credit facility expiring in 2023, and three bilateral credit facilities, totalling $240 million, expiring in 2021.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, Kent Hills Wind LP and TransAlta OCP non-recourse bonds with a carrying value of $1,143 million (Dec. 31, 2018 - $1,235 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2019. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2020. At Dec. 31, 2019, $42 million (Dec. 31, 2018 -$33 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2019.

Proceeds received from the Big Level and Antrim tax equity financing in the amount of $91 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying outstanding project development costs.

Working Capital
Including the current portion of long-term debt and lease obligations, the excess of current assets over current liabilities was $224 million as at Dec. 31, 2019 (2018 - $432 million). Our working capital decreased year over year mainly due to the $400 million debenture payable in 2020. Excluding the current portion of long-term debt and lease obligations of $513 million, the excess of current assets over liabilities was $737 million as at Dec. 31, 2019 (2018 - $580 million), an increase of $157 million, mainly due to higher cash and cash equivalents and repayments on the credit facility as a result of receiving the $350 million exchangeable debentures issued in May 2019 to Brookfield, as well as strong cash flow from operating activities.

Share Capital
Our Series C and Series E Cumulative Redeemable Rate Reset Preferred Shares failed to receive the required number of minimum votes in 2017 to give effect to conversions into Series D and Series F, respectively; accordingly, both the Series C and Series E Preferred Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The Series G Cumulative Redeemable Rate Reset Preferred Shares also failed to receive the required number of minimum votes in 2019 to give effect to conversions into Series H. Therefore, the Series G Preferred Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board.

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

As at	Mar. 3, 2020	Dec. 31, 2019	Dec. 31, 2018
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**277.0**	**277.0**	284.6
Preferred shares			
Series A	10.2	**10.2**	10.2
Series B	1.8	**1.8**	1.8
Series C	11.0	**11.0**	11.0
Series E	9.0	**9.0**	9.0
Series G	6.6	**6.6**	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests
As of Dec. 31, 2019, we own 60.4 per cent (2018 – 60.9 per cent) of TransAlta Renewables. In 2019, our ownership percent decreased due to TransAlta Renewables issuing approximately two million common shares under their Dividend Reinvestment Plan ("DRIP"). We do not participate in this plan.

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

We also own 50.01 per cent of 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. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2019, decreased by $14 million to $94 million compared to 2018 Earnings were down at TransAlta Renewables in 2019 mainly due to lower finance and interest income from subsidiaries of TransAlta, foreign exchange losses due to the weakening of the Australian dollar and higher depreciation expense, partially offset by an increase in the fair value of investments in subsidiaries of TransAlta. Earnings from TA Cogen were higher in 2019 mainly due to strong Alberta pricing and lower costs of fuel at the coal-fired generating facility.

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

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2019	2018	2017
Interest on debt	**161**	184	218
Interest on exchangeable securities	**20**	—	—
Interest income	**(13)**	(11)	(7)
Capitalized interest	**(6)**	(2)	(9)
Loss on redemption of bonds	**—**	24	6
Interest on finance lease obligations	**4**	3	3
Credit facility fees, bank charges, and other interest	**15**	13	18
Tax shield on tax equity financing	**(35)**	—	—
Other[1]	**10**	15	(3)
Accretion of provisions	**23**	24	21
Net interest expense	**179**	250	247

(1) In 2019, other interest expense included approximately $5 million (2018 - $7 million, 2017 - nil) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable.

Net interest expense was lower in 2019 primarily due to the $35 million credit related to the tax shield (tax benefit on tax depreciation) claimed in 2019 on the Big Level and Antrim projects and allocated to the tax equity investor. In addition, there were no prepayment premiums in 2019 as there were no early redemptions of bonds during the year, compared to 2018, which included $24 million in prepayment premiums.

Net interest expense was higher in 2018 compared to 2017, due to the $5 million prepayment premium relating to the early redemption of the US$500 million senior notes, $5 million of costs expensed in connection to a project-level financing that is no longer practicable, the $19 million prepayment premium relating to the early redemption of the $400 million debenture and lower capitalized interest. These increases were partially offset by lower interest on debt as a result of lower debt levels.

Dividends to Shareholders

The declaration of dividends is at the discretion of the Board. The following are the common and preferred shares dividends declared each quarter during 2019 and the first quarter of 2020:

	Payable date		Common dividends	Preferred Series dividends per share				
Declaration date	**Common shares**	**Preferred shares**	**per share**	**A**	**B**	**C**	**E**	**G**
Apr 15, 2019	Jul 1, 2019	Jun 30, 2019	0.0400	0.16931	0.23136	0.25169	0.32463	0.33125
Jul 16, 2019	Oct. 1, 2019	Sept. 30, 2019	0.0400	0.16931	0.23422	0.25169	0.32463	0.33125
Oct. 9, 2019	Jan. 1, 2020	Dec. 31, 2019	0.0400	0.16931	0.23113	0.25169	0.32463	0.31175
Jan. 16, 2020	Apr 1, 2020	Mar 31, 2020	0.0425	0.16931	0.22949	0.25169	0.32463	0.31175

2020 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2020 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	Target
Comparable EBITDA	$925 million to $1,000 million
FCF	$325 million to $375 million
Dividend	$0.17 per share annualized

Range of key power price assumptions

Market	Power Prices ($/MWh)
Alberta Spot	$53 to $63
Mid-C Spot (US$)	$25 to $35

Other assumptions relevant to the 2020 financial outlook

Sustaining capital	$170 million to $200 million

Operations

Market Pricing and Hedging Strategy

For 2020, power prices in Alberta are expected to be comparable to 2019 given similar overall supply and demand conditions; however, weather and demand are major factors in actual settled prices. Pacific Northwest power prices for 2020 are expected to be lower than 2019 as 2019 prices were impacted by specific events in the first quarter that are not expected to occur in the future. Ontario power prices are expected to be comparable or higher than 2019 prices.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF that 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

For the Alberta thermal fleet, we expect the 2020 cash fuel costs per tonne of coal to be higher than the 2019 costs as mine volumes are declining, resulting in slightly less mine cost efficiency. Coal volumes are declining as a result of increased gas consumption in the Alberta thermal fleet. This change in fuel mix will drive lower GHG emissions and the combined effect will result in lower total fuel and GHG costs for a given volume of power production.

In the Pacific Northwest of the US, the coal mine adjacent to our Centralia 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 rail freight costs fluctuate partly with gas prices. The delivered fuel cost in 2020 is expected to be consistent with 2019 costs.

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

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2020 objective for Energy Marketing is for the segment to contribute between $75 million to $85 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies
Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense
Interest expense for 2020 is expected to be higher than in 2019 largely due to higher levels of debt. The increase in debt is mainly due to expected drawings on our credit facilities as we execute on our growth plans as well as the exchangeable debentures issued in May 2019 to Brookfield and the $400 million exchangeable preferred shares, which are expected to be issued to Brookfield in October 2020. In addition, changes in interest rates on variable debt, and in the value of the Canadian dollar relative to the US dollar can affect the amount of interest expense incurred.

Liquidity and Capital Resources
We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.7 billion in liquidity including $411 million in cash. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturity in 2020 and 2022. Refer to the Corporate Strategy and Financial Capital sections of this MD&A for further details.

Sustaining and Productivity Capital Expenditures
Our estimate for total sustaining and productivity capital is allocated among the following:

Category	Description	Spent in 2018	Spent in 2019	Expected spend in 2020
Routine capital[1]	Capital required to maintain our existing generating capacity	50	**50**	60 - 80
Planned major maintenance	Regularly scheduled major maintenance	58	**68**	100 - 110
Mine capital	Capital related to mining equipment and land purchases	42	**23**	10 - 10
Total sustaining capital[2]		150	**141**	**170 - 200**
Insurance recoveries of sustaining capital expenditures	Insurance proceeds - 2019 relates to the tower fires at Wyoming Wind and Summerview	(7)	**(10)**	— - —
Total sustaining capital		143	**131**	**170 - 200**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	21	**9**	10 - 15
Total sustaining and productivity capital		164	**140**	**180 - 215**

(1) Includes hydro life extension expenditures.
(2) On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. Refer to the Accounting Changes section of this MD&A for further details.

Significant planned major outages at TransAlta's operated units for 2020 include the following:
- One outage for major maintenance at Sundance Unit 6 within our Canadian Coal segment during the third and fourth quarters of 2020. This work will be undertaken in parallel with the coal-to-gas conversion of this unit;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on planned component replacements.

There is also one major planned outage at one of our non-operated units in 2020:
- An outage for major maintenance at Sheerness Unit 2 during the first quarter of 2020. This work will be undertaken in parallel with the coal-to-gas conversion of this unit.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2020:

	Coal	Gas and renewables	Total
GWh lost	700 - 800	450 - 500	1,150 - 1,300

Funding of Capital Expenditures
Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities and existing liquidity. We have access to approximately $1.7 billion in liquidity, if required. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

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.

Competitive Forces

Supply and demand balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity, whereas system capacity, natural gas prices, GHG pricing, government subsidies and renewable resource availability are key drivers to the supply. Growth in behind-the-fence generation for mining investments is key to developing our Australian gas segment.

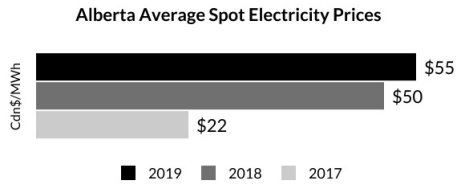
Renewable capacity addition has been strong for the past several years due to government incentives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable electricity as well as natural-gas-fired generation. This expectation is driven by the low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

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

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

Alberta

Approximately 57 per cent of our gross installed capacity is located in Alberta and approximately 42 per cent of this is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. The Sundance 1 and 2 Alberta PPAs expired at the end of 2017, the Sundance 3 to 6 PPAs were terminated effective March 31, 2018, and the Keephills 1 and 2, Sheerness and hydro PPAs will expire at the end of 2020. The Balancing Pool acts as buyer for the Keephills and Sheerness PPAs as a result of the terminations in 2016 by the original buyers.



In the third quarter of 2019, we announced our Clean Energy Investment Plan, which includes converting our existing Alberta coal assets to natural gas, which will position TransAlta's fleet as a low-cost generator in Alberta. See further details in the Corporate Strategy section of this MD&A.

Coal generation sold under certain Alberta PPAs retains some exposure to market prices as we pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of electricity and Ancillary Services in excess of obligations on our Hydro Alberta PPAs. We enter into financial contracts to reduce our exposure to variable power prices for a significant portion of our remaining generation.
Alberta's annual demand was flat from 2018 to 2019. The average pool price increased from $50.29/MWh in 2018 to $54.88/MWh in 2019. The majority of the pool price increase was due to higher settled prices during the first quarter of 2019. The higher prices also positively impacted our merchant wind and hydro portfolio.

Our market share of offer control in Alberta in 2019 was approximately 21 per cent (16 per cent if the Sundance mothballed units are excluded from offer control).

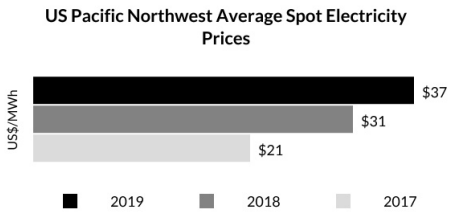
In late November 2016, we announced that we entered into an Off Coal Agreement with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal.

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

Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool announced the complete termination of the Sundance B and C PPAs, effective Mar. 31, 2018. As of Apr. 1, 2018, the Sundance plant has been operated as a merchant facility. There has been no announcement yet concerning the Keephills PPA. TransAlta continues to operate the Keephills PPA generating units in their ordinary course and receives the capacity and energy payments due to TransAlta under the PPAs.

US Pacific Northwest

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



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

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

Contracted Gas and Renewables

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

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

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

Power-Generating Portfolio Capital

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

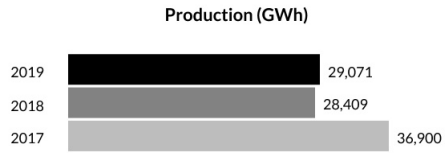
Availability and Production

Our availability target for our Canadian Coal fleet was 87 to 89 per cent for 2019. We achieved 89 per cent (2018 - 93 per cent, 2017 - 82 per cent) availability in Canadian Coal. Our availability target for our other generating assets (gas and renewables) was in the range of 92 to 96 per cent in 2019. Both Canadian Gas and Wind and Solar achieved the higher end of this range. Canadian Gas achieved 95 per cent (2018 - 93 per cent, 2017 - 92 per cent) and Wind and Solar achieved 95 per cent (2018 - 95 per cent, 2017 - 96 per cent). As a result of unplanned outages, Australian Gas achieved 91 per cent (2018 - 94 per cent, 2017 - 93 per cent), slightly less than the target.



Our availability for the entire fleet in 2019, after adjusting for dispatch optimization at US Coal, was 90 per cent (2018 - 91 per cent, 2017 - 87 per cent) and was slightly lower than last year. Higher planned outages at Canadian Coal, forced outages and derates at US Coal and unplanned outages at Australian Gas, were partially offset by lower planned outages at Canadian Gas.

Production for the year ended Dec. 31, 2019, increased 662 GWh compared to 2018. The increase was mainly at US Coal where production increased 1,787 GWh due to higher merchant pricing in the first half of 2019 and timing of dispatch optimization. This was partially offset by Canadian Coal where production decreased 1,381 GWh primarily due to the mothballing and retirement of certain Sundance units as well as planned outages, partially offset by lower unplanned outages.



Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital that ensures our facilities operate reliably and safely over a long period of time.

Year ended Dec. 31	**2019**	2018	2017
Routine capital	**50**	50	69
Mine capital	**23**	42	28
Planned major maintenance	**68**	58	121
Total sustaining capital expenditures[1]	**141**	150	218
Productivity capital	**9**	21	24
Total sustaining and productivity capital expenditures[1]	**150**	171	242
Insurance recoveries of sustaining capital expenditures	**(10)**	(7)	—
Net amount	**140**	164	242

(1) On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.

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

Year ended Dec. 31	**2019**	2018	2017
GWh lost[1]	**935**	381	1,234

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

Total sustaining capital expenditures were $9 million lower compared to 2018 and total productivity capital was $12 million lower in 2019 compared to 2018. The productivity capital expenditures relate to the funding of some Greenlight transformation initiatives. Refer to the Corporate Strategy section of this MD&A for further details on our Greenlight program. In certain cases, payback is expected to be achieved within three years. We also completed planned major outages at Keephills Unit 1, Sundance Unit 4 and Sarnia.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each cash-generating unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between our market capitalization and our book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia Plant CGU exceeded the carrying value, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	**2016**
Mid-Columbia annual average power prices	**US$30 to US$42 per MWh**	US$22 to US$46 per MWh
On-highway diesel fuel on coal shipments	**US$2.35 to US$2.40 per gallon**	US$1.69 to US$2.09 per gallon
Discount rates	**5.2 to 6.4 per cent**	5.4 to 5.7 per cent

During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings. Refer to Note 3 and 22 of the consolidated financial statements for further details.

Assets Held for Sale

In the fourth quarter of 2019, the Corporation identified several trucks and associated inventory to be sold within the Canadian Coal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

2018

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

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

2017

Sundance Unit 1
In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

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

Project Development Costs
During 2019, the Corporation wrote off $18 million (2018 - $23 million) in project development costs related to projects that are no longer proceeding.

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2019, we provided letters of credit totalling $690 million (2018 - $720 million) and cash collateral of $42 million (2018 - $105 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities, defined benefit obligation and other long-term liabilities and decommissioning and other provisions.

Commitments

Contractual commitments are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas, transportation and other contracts	125	125	120	128	131	1,493	**2,122**
Transmission	9	5	4	3	—	—	**21**
Coal supply and mining agreements[1]	147	16	16	16	8	14	**217**
Long-term service agreements	50	22	32	17	15	14	**150**
Non-cancellable operating leases[2]	4	2	2	2	3	64	**77**
Long-term debt[3]	494	98	625	372	105	1,410	**3,104**
Exchangeable securities[4]	—	—	—	—	—	350	**350**
Principal payments on lease obligations	19	14	9	6	4	90	**142**
Interest on long-term debt and lease obligations[5,6]	161	138	128	98	87	671	**1,283**
Interest on exchangeable securities[4,6]	25	25	25	24	24	—	**123**
Growth	535	254	196	270	13	—	**1,268**
TransAlta Energy Transition Bill	6	6	6	6	—	—	**24**
Total	**1,575**	**705**	**1,163**	**942**	**390**	**4,106**	**8,881**

(1) Commitments related to Sheerness may be impacted by the cessation of coal-fired emissions on or before Dec. 31, 2030.
(2) Includes leases that have not yet commenced.
(3) Excludes impact of derivatives.
(4) Assumes the exchangeable debentures will be exchanged by Brookfield on Jan. 1, 2025. Refer to the Significant and Subsequent Events section of this MD&A for further details.
(5) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.
(6) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement ("MoA"), we have committed to fund US$55 million in total over the remaining life of the Centralia plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required. At Dec. 31, 2019, the Corporation has funded approximately US$37 million of the commitment.

Contingencies

Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding before the Alberta Utilities Commission. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016 and issue a single invoice charging or crediting market participants for the difference in losses charges. A more recent decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was to be issued in April 2021, with cash settlement expected in June 2021. The current total estimate of exposure based on known data is approximately $12 million. However, the AESO recently requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, resulting in invoices being issued as early as April 2020 for settlement in June 2020, a year earlier than anticipated. The Corporation is challenging this request.

FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first dispute arose as a result of FMG's attempted termination of the South Hedland PPA on the basis that the conditions to establishing commercial operation under the South Hedland PPA had not been met. TransAlta's view is that all conditions to establishing commercial operation under the terms of the South Hedland PPA had been satisfied in full. TransAlta initiated legal action against FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. This matter is scheduled to proceed to trial beginning June 15, 2020.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

Mangrove Claim
On Apr. 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming the Corporation, the incumbent members of the Board of Directors of TransAlta on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is alleging, among other things, oppression by the Corporation and the named directors and is seeking to set aside the 2019 Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020.

Keephills 1 Superheater
Keephills Unit 1 was taken offline from Mar. 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool is attempting to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. TransAlta denied the Balancing Pool had the right to do so. The Alberta Court of Queen's Bench confirmed the Balancing Pool has a right under the PPA to commence an arbitration, independent of the PPA buyer. On Sept. 4, 2019, the Alberta Court of Appeal upheld the lower court's decision. TransAlta sought permission to appeal the Alberta Court of Appeal's decision to the Supreme Court of Canada. The application was denied and the matter will now proceed to arbitration, with a hearing potentially sometime in 2020.

Sundance A Decommissioning
TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the mine. The Balancing Pool filed a statement of intent to participate as an intervener because it disagrees that, amongst other things, the mine decommissioning costs should be included. TransAlta anticipates it will receive payment from the Balancing Pool in 2020 for its decommissioning costs; however, the amount is uncertain.

Hydro PPA Renewable Energy Credits
The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $27 million, earned by the Hydro plants under the *Carbon Competitiveness Incentive Regulation* ("CCIR") in 2018 and 2019. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. We anticipate this dispute will be resolved by the end of 2021.

Direct Assigned Capital Deferral Account Application
AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 direct assigned capital deferral account for the Edmonton region: 240 kV line upgrades project (the "Proceeding"). TransAlta is a secondary applicant in the Proceeding. Altalink and TransAlta seek to have their costs approved by the AUC as reasonable and prudent. The Enoch Cree Nation ("ECN") and the Consumers Coalition of Alberta are registered participants in the Proceeding. Currently Altalink, ECN and TransAlta's interests are closely aligned. TransAlta believes it has a reasonable chance of having its costs (estimated at about $21 million) approved.

Critical Accounting Policies and Estimates

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

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

Our significant accounting policies are described in Note 2 of the consolidated financial statements. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, other provisions and joint arrangements. Each policy involves a

number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our Audit, Finance and Risk Committee ("AFRC") and our independent auditors. The AFRC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A. These critical accounting estimates are described as follows:

Revenue Recognition

Revenue from Contracts with Customers

In 2018, the Corporation adopted IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"). Comparative information prior to 2018 was not restated and is reported under IAS 18 *Revenue*. The Corporation's accounting policies for the current and prior periods for revenue recognition are outlined in Note 2 of the consolidated financial statements. The significant judgments and estimates have been highlighted below.

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

Identification of Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Corporation's contracts may contain more than one performance obligation. Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

Transaction Price

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

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

Allocation of Transaction Price to Performance Obligations

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

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

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

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

Revenue from Other Sources
Lease Revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

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

The determination of the fair value of commodity risk management contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility and liquidity, among other factors. Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or models described below.

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications
The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

Level I
Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date. In determining Level I fair values, we use quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

Level II
Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials. Our commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

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

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

We may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be 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 price relationships. We also have various contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

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

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques for contracts included in the Level III fair value measurements at Dec. 31, 2019, is an estimated total upside of $79 million (2018 - $149 million upside) and total downside of $172 million (2018 - $149 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $46 million upside (2018 - $116 million upside) and $139 million downside (2018 - $116 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$20-US$28 (Dec. 31, 2018 - US$20-US$35) for the period from 2020 to 2025, while the remaining amounts account for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

In addition to the Level III fair value measurements discussed above, the Brookfield Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum of 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the option to exchange is considered a Level III fair value measurement, with an estimated upside of $35 million and downside of $27 million potential impact to the carrying value of nil as at Dec. 31, 2019. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that PP&E and finite life intangible assets are impaired or whether a previously recognized impairment may no longer exist or may have decreased. Impairment exists when the carrying amount of the asset or CGU to which it belongs exceeds its recoverable amount, which is the higher of fair value less costs of disposal and value in use.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used or in our overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our operations, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or CGU to which the asset belongs. The recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. We evaluate the market design, transmission constraints and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. We evaluate synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential, and we consider our own performance measurement processes in making this determination. No changes arose in our CGUs in 2019.

Impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. As a result of our review in 2019 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Refer to the Other Consolidated Analysis section of this MD&A for further details.

Project Development Costs

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

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2019, total depreciation and amortization expense was $709 million (2018 - $710 million, 2017 - $708 million), of which $119 million (2018 - $136 million, 2017 - $73 million) relates to mining equipment and is included in fuel, carbon compliance and purchased power.

As a result of the Clean Energy Investment Plan described in the Corporate Strategy section of this MD&A, we will convert our existing Alberta coal assets to natural gas and therefore the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were updated to reflect these changes. For certain Wind and Solar PP&E we identified additional components for parts with shorter useful lives than originally estimated and revised the useful lives accordingly. See the Accounting Changes section of this MD&A for further details.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss.

For purposes of the 2019, 2018 and 2017 annual goodwill impairment reviews, the Corporation determined the recoverable amounts of the CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs or groups of CGUs to which goodwill relates, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins, and fuel and operating costs. No reasonably possible change in the assumptions would have resulted in an impairment of goodwill.

Leases

In determining whether our contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where we are a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with us, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how we classify amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense are dependent upon such classifications.

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

A net deferred income tax liability of $454 million (2018 - $473 million) has been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2019. This primarily relates to income tax deductions in excess of related depreciation of PP&E of $828 million (2018 - $896 million), taxes on unrealized gains from risk management transactions of $141 million (2018 - $145 million), partially offset by temporary differences related to future decommissioning and restoration costs of $122 million (2018 - $113 million) and net operating loss carryforwards of $252 million (2018 - $281 million). We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist. Additional US tax losses are available for use for which no deferred income tax assets have been recognized.

Employee Future Benefits

We provide selected pension and other post-employment benefits to employees, such as health and dental benefits. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liabilities for pension, other post-employment benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in the return on plan assets as a result of actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for generating facilities and mine sites in the period in which they are incurred if there is a legal or constructive obligation to remove the facilities and restore the site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the current market-based risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2019, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $501 million (2018 - $407 million). During 2019, we adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. Refer to the Accounting Changes section of this MD&A for further details. In addition, as a result of the changes in estimated useful lives, described in the Accounting Changes section, the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed due to the change in useful life. The use of a lower inflation rate decreased the corresponding liabilities.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.3 billion, which will be incurred between 2020 and 2073. The majority of these costs will be incurred between 2020 and 2050.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	5
Undiscounted decommissioning and restoration provision	10	3

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using our best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, which classification affects the accounting for the joint arrangement. In making this classification, the Corporation exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

Accounting Changes

Current Accounting Changes

IFRS 16 *Leases*

We adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases.

We elected to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the consolidated financial statements were not restated, and comparative period leases continue to be reported as recognized following IAS 17 *Leases* or International Financial Reporting Interpretations Committee Interpretation 4 *Determining Whether an Arrangement Contains a Lease*. Instead of restating prior years' results, we recognized the cumulative impact of the initial application of the standard of $3 million in deficit as at Jan. 1, 2019.

Impact on the financial statements

Lessee

We recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease obligation measured at the present value of the remaining lease payments discounted using our incremental borrowing rate (or the rate implicit in the lease) applied to the lease obligations at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease obligations on Jan. 1, 2019, was 5.71 per cent. On Jan. 1, 2019, we recognized $83 million in lease obligations, comprised of $52 million of new lease obligations and $31 million (net of $32 million derecognized) that were previously shown as finance lease obligations.

The associated right of use assets were measured at an amount equal to the lease obligation, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, we recognized right of use assets of $85 million, including $38 million that was previously included in PP&E, intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16, resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in deficit.

Lessor

Several of the Corporation's long-term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for by applying IFRS 15 *Revenue from Contracts with Customers.* No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

Note 2 and Note 3 of the consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 16 and our adoption of IFRS 16, respectively.

Change in Estimates

Canadian Coal

As a result of the Clean Energy Investment Plan described in the Corporate Strategy section of this MD&A, we adjusted the useful lives of certain coal assets, effective Sept. 1, 2019. Assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined-cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019, increased by approximately $16 million.

Wind and Solar

During 2019, the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. Accordingly, depreciation expense for the year ended Dec. 31, 2019, increased by approximately $11 million.

Sheerness

In 2019, we adjusted the useful life of the Sheerness coal-fired plant assets to align with the dual-fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the year ended Dec. 31, 2019, decreased by approximately $8 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia

In 2019, we adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

For further details and changes in estimates relating to prior years, refer to the Other Consolidated Analysis section of this MD&A and Note 3 of the consolidated financial statements.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices and currency fluctuations, as well as other market risks. We may currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale, or usage requirements ("own use") and as such, are not considered financial instruments and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge. Our financial instruments are mainly used for cash flow hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion is recognized in net earnings.

We have certain contracts in our portfolio that, at their inception, do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

The fair value of derivatives that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate or commodity hedges and are used to offset foreign exchange, interest rate and commodity price exposures resulting from market fluctuations.

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

Physical and financial swaps, forward sale and purchase contracts, futures contracts and options may be used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps may be used to offset the exposures resulting from foreign-denominated long-term debt. Interest rate swaps may be used to convert the fixed interest cash flows related to interest expense at debt to floating rates and vice versa.

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

Hedge accounting follows a principles-based approach for qualifying hedges, which is aligned with an entity's approach to risk management. When we do not elect hedge accounting or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest or exchange rates related to these financial instruments are recorded in net earnings in the period in which they arise.

Net Investment Hedges

Foreign-denominated long-term debt is used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. Our net investment hedges using US-denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our US operations with interest payments on our US-dollar debt.

Non-Hedges

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

Fair Values

The majority of fair values for our project, foreign exchange, interest rate, commodity hedges and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the consolidated financial statements. At Dec. 31, 2019, Level III instruments had a net asset carrying value of $686 million (2018 - $695 million). Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2018.

Environment, Social and Governance ("ESG")

The Corporation places high priority on ESG or sustainability management and performance. We have reported on sustainability for over 25 years and fiscal 2019 reporting marked our fifth year of integrating financial and sustainability disclosure.

In total, we own 73 power-generating facilities across Australia, Canada and the US. We are invested in a mix of wind, solar, hydro, natural gas and coal assets for a total of approximately 8,000 MW of gross generating capacity. The following outlines material environmental and social considerations in respect of our operated facilities.

ESG at TransAlta - Environment, Social and Governance Objectives

Sustainability is a core value for the Corporation. For TransAlta, it means integrating actions into our current plans that recognize the long-term impacts of our operations on the environment and society. Our programs also ensure that we work with stakeholders in the community and use leading governance practices in our decision-making processes. We believe that integrating the three pillars of environment, social and governance is important to the long-term decisions we make for the benefit of all our stakeholders.

Our coal-to-gas conversion strategy and pursuit of strategic growth opportunities in clean electricity (renewable and natural gas) generation highlights one element of our environment pillar. By 2025 our generation portfolio will be comprised entirely of renewable and natural gas assets. Natural gas is a clean fuel that plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. Our focus on clean electricity generation also mitigates the impact of potential adverse regulatory developments in response to emerging environmental regulation including, but not limited to, a regulated cost of carbon.

Environmental and Social Risk and Materiality

Our major environmental risk factors include weather, environmental disasters, climate change, exposure to the elements, environmental compliance risk, and current and emerging environmental regulation. Our major social risk factors include public health and safety, employee and contractor health and safety, local communities, employee retention, reputation management, and stakeholder relationships. Further guidance on our risk factors can be found in the Risk Management section of this MD&A.

Reporting Structure

Key elements of the following disclosure are guided by our sustainability materiality assessment. To help inform discussion and provide context on how ESG affects our business, we have applied components of leading ESG reporting frameworks, including Global Reporting Index, Sustainability Accounting Standards Board ("SASB") and Task Force on Climate-related Financial Disclosures ("TCFD"). Our content is structured according to guidance on non-traditional capitals from the International Integrated Reporting Framework.

Human Capital

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

As of Dec. 31, 2019, we had 1,543 (2018 - 1,883) active employees. This number has decreased by 18 per cent from 2018 levels, following a reduction in positions at our coal fleet aligned to changes in the plant portfolio and from multiple initiatives across the business that used technology to reduce costs and increase efficiency.

With approximately 45 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith, and we respect the rights of employees to participate in collective bargaining.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our more than 100-year heritage. Our core values are safety, innovation, sustainability, respect and integrity. These five core values help provide clarity for our employees and guide our behaviour and decision making. They also provide a foundation for leadership, collaboration, community support, personal growth and work/life balance. Through corporate initiatives and support throughout all levels of leadership, we encourage our employees to maximize their potential.

Our six-level organizational structure helps facilitate effective pace and decision-making in our organization. Our business operates as a business-centric model, with Canadian Coal, US Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro as our six generating segments. In addition, our Energy Marketing segment optimizes our asset fleet and trades electricity and other energy commodities. Our Corporate segment, including finance, legal, administrative, business development and investor relations functions, oversees our business and provides strategic alignment. The Corporation also includes a Shared Services division which oversees our information technology, supply chain, human resources, engineering and accounting functions. The consolidation and centralization of these functions has allowed us to streamline, standardize and where appropriate automate these functions while reducing costs and improving service delivery across the organization. Our operations portfolio is run by a single leadership team, which provides operational and financial synergies, enhancing our competitiveness.

TransAlta is committed to improving its internal work environment and the way that employees perceive their work and the Corporation. We track a broad number of factors to provide us insight into our progress and we use a third party to assist us in tracking our progress on an annual basis. We have made continual and notable improvements year over year and continue to target further improvements as we look forward.

Health and Safety

The safety of our people, communities and the environment is one of our core values. At TransAlta, we operate large and often complex facilities. The environments in which we work, including Canadian winters and the Australian outback, can add additional challenges to keeping our employees, contractors and visitors safe. Each year we invest significant resources into improving our safety performance, including positively enhancing our safety culture. At meetings of more than four people, we have a practice of starting the meeting with a "safety moment", which helps share key safety learnings across the Corporation.

TransAlta's management systems underpin the delivery of safe, reliable and competitive electricity to our customers and partners. Our Total Safety Management System (TSMS) is a combination of recognized best practices in process safety, risk management, asset management, occupational health, safety and environmental management. Since expanding our Occupational Health and Safety program in 2015 to encompass Total Safety, we have transitioned from development and implementation of this framework into continuous improvement, always striving to achieve our Target Zero vision to operate our business with zero unexpected asset failures and zero environmental, health and safety incidents.

In 2019, we continued to progress our safety culture transformation and have provided employees with behavioural safety training tools and capabilities to improve both their personal safety and that of their coworkers.

In 2017, we introduced the Total Injury Frequency (TIF) metric to track the total number of injuries including minor first aids, relative to exposure hours worked.

In 2019, we achieved a TIF of 1.12 compared to 1.91 in 2018. This decrease was a direct result of our back-to-basics approach with respect to safety. Specifically, in 2019, we focused on hazard identification (including audits and inspections), housekeeping and improved contractor management practices across the fleet.

In addition to TIF, we are also tracking Total Recordable Injury Frequency (TRIF). TRIF tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked. TRIF provides us with the opportunity to target and monitor our significant injuries. It is also an industry-recognized safety metric and allows us to compare and benchmark our safety performance to that of our peers. Our TRIF result for 2019 was 0.73 compared to 1.00 in 2018.

Safety at TransAlta (employees and contractors)	**2019**	**2018**	**2017**
Lost-time injuries	**5**	1	6
Medical aids	**7**	12	15
Restricted work injuries	**3**	12	16
First aids	**8**	23	67
Total TIF injuries	**23**	48	104
Exposure hours	**4,106,898**	5,014,804	6,073,419
Total Injury Frequency (TIF)	**1.12**	1.91	3.42
Total Recordable Injury Frequency (TRIF)	**0.73**	1.00	1.22

Gender Diversity

A number of case studies have highlighted the link between gender diversity and additional business value. TransAlta is an active supporter of gender diversity as a driver for value, but also as an ethical business practice. Our commitment to gender diversity in our business is evidenced by our female participation rates on both our executive team and Board. As of Dec. 31, 2019, women made up 50 per cent of our executive officer team and 33 per cent of our Board. These percentages are higher than our peers in Canada. Industry research highlights that the percentage of Board seats held by women from all disclosing Canadian TSX-listed companies in Canada is 18.1 per cent and the average percentage of women on executive teams is 16.9 per cent.

To further support female advancement, we have set targets to: (i) maintain equal pay for women in equivalent roles, (ii) achieve 50 per cent representation of women on our Board by 2030 and (iii) achieve 40 per cent representation of women among all employees by 2030. Currently, women employees represent 20 per cent of all employees.

In early 2020, TransAlta was one of 325 companies globally to be added to the Bloomberg Gender Equality Index. Inclusion in the index recognizes our comprehensive investment in workplace gender equality and our commitment to driving progress by developing inclusive policies and disclosing data using Bloomberg's gender reporting framework.

Employee Retirement Savings Programs

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

Retirement savings plans are an example of rewards we provide. We have registered pension plans in Canada and the US. The plans cover substantially all employees of the Corporation, its domestic subsidiaries and specific named employees working internationally. These plans have defined benefit ("DB") and defined contribution ("DC") options, and in Canada there is an additional non-registered supplemental pension plan ("SPP") for members whose annual earnings exceed the Canadian income tax limit. The DB SPP was closed as of Dec. 31, 2015, and a new DC SPP commenced for only executive members hired after Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered in the DB SPP.

The Canadian and US DB pension plans are closed to new entrants, with the exception of the Highvale mine (SunHills) pension plan acquired in 2013. The US DB pension plan was frozen effective Dec. 31, 2010. The plans are funded by the Corporation in accordance with governing regulations and actuarial valuations. In addition, in Canada, we provide some optional plans for employees to enhance their financial wellness and retirement savings, with group RRSP and TFSA plans.

In Australia, employees can nominate a superannuation fund for superannuation contributions. The Australian superannuation scheme is compulsory for employers with contributions required at a rate set by the government.

Other Employee Benefit Programs
TransAlta provides competitive benefit programs for most of our employees (options are dependent on the countries in which we operate). We also provide benefit programs based on negotiated union agreements in some locations.

Our flexible benefits plans provide employees and their families with choices of coverage including, among others, extended health, dental, vision, life insurance, critical illness, accident, disability and a health spending account.

We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65. The Canadian retiree benefits plan was closed for all new hired employees as of Mar. 1, 2017.

Talent and Employee Development
Talent and employee development is viewed as a key pillar of organizational health. Investing in our employee development enhances employees' skills and improves productivity and engagement. This contributes to a strong corporate culture that provides value for TransAlta.

In 2019, we launched our Leadership Development Program. This program provides 143 leaders or future leaders with fundamental leadership skills and tools. Training programs focused on a variety of leadership competencies for leaders with various years of management experience. All leaders in Canada also completed mandatory Violence in the Workplace training.

In addition, in 2019 we developed and launched our Operations Manager Development Program. This is an internally designed program to develop future plant managers and operations leaders by providing on-the-job experience and structured learning activities within multiple business units across the organization. Participants learn through an 18-month program of rotational assignments in various operational facilities (Coal, Gas, Wind and Hydro) as well as through Corporate business units (Asset Management, Commercial, Energy Trading & Marketing, Finance, Human Resources, Indigenous & Stakeholder Relations, Growth and Supply Chain). In 2019, we had seven participants in this program.

We also continued to offer our existing internal programs to employees across the organization. This includes our Elevate Program, a six-month peer-led leadership training program. This program first launched in 2017, and in 2019, we had 100 participants. Since the launch of this program, 215 leaders and future leaders have participated.

Another internal program that we continue to offer is Execution Engine. This program was designed to build capacity for our people to create an organization that is both efficient and adaptive. The training program was built on research regarding what is needed for our people to help drive and sustain change. To date, approximately 850 employees have taken this course. In December 2019, we also launched an internal leadership library that is updated monthly and gives all employees access to articles about leadership development.

Social and Relationship Capital

We strive to create shared value for our stakeholders through social and relationship value creation at TransAlta. The most material impacts on our social and relationship performance are public health and safety, anti-competitive behaviour and fostering positive relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners in the areas where we operate.

Indigenous Relationships and Partnerships
At TransAlta, we value our relationships and partnerships with stakeholders and our Indigenous neighbours. Our Indigenous Relations team focuses on community engagement, employment, economic development and community investment. We ensure that TransAlta's principles for engagement are upheld and that the Corporation fulfills its commitments to Indigenous communities. Efforts are focused on building and maintaining solid relationships and establishing strong communication channels that enable TransAlta to share information regarding operations and growth initiatives, gather feedback to inform project planning and understand priorities and interests from communities to better address concerns.

Methods of engagement include:

- Relationship building through regular communication and in-person meetings with representatives at various levels within Indigenous community organizations;
- Hosting company-community activities that share both business information and cultural lessons;
- Maintaining consistent communications with each community and following appropriate community protocols and procedures;
- Participating in community events such as powwows and blessing ceremonies; and
- Providing both monetary and in-kind sponsorships for community initiatives.

TransAlta is proactive with initiating engagement early on in project development to allow concerns to be identified promptly and addressed, minimizing potential project delays. We conduct consultation primarily during project development and decommissioning and maintain engaged communication throughout the operation phase. We work with communities to build a relationship with a foundation of ongoing communication and mutual respect.

In 2019, TransAlta partnered with Indspire, Canada's national Indigenous registered charity, and we were able to award 14 bursaries of $3,000 each. The Indigenous recipients were from the following communities: Aamjiwnaang First Nation, Blood Tribe, Ermineskin Cree Nation, Paul First Nation, Piikani Nation, Samson Cree Nation, Simpcw First Nation, Squamish Nation, Sunchild First Nation and Tsuut'ina Nation.

We currently hold a silver-level standing with the Canadian Council for Aboriginal Business's Progressive Aboriginal Relations ("PAR"). Certification occurs every three years and is a comprehensive, third-party audit conducted by PAR verifiers. To support this initiative, TransAlta introduced an internal practice and knowledge centre that provides employees with resources and information to support the advancement of Indigenous relations at TransAlta.

In 2020, TransAlta continues to support Indigenous access to education through our Indigenous funding program with the Southern Alberta Institute of Technology (SAIT). TransAlta recognized a gap in federal and provincial funding for academic upgrading, which could contribute to a barrier for many Indigenous students. This program provides the critical financial support to aspiring Indigenous students applying to SAIT who require high school upgrading in order to qualify for a trade program.

In 2019, we also supported an Indigenous Leadership Program at the Banff Centre for Arts and Creativity. Approximately 300 Indigenous leaders from over 120 communities attended the leadership programs with help from TransAlta and other supporters.

Over the past five years, TransAlta's support has provided 45 bursaries for members of Indigenous communities to attend programs and share what they have learned with their comminuties. Participants have come from communities across Alberta and British Columbia including Alexis Nakota Sioux Nation, Bearspaw First Nation, Chiniki First Nation, Enoch Cree Nation, Ermineskin Cree Nation, Fort McKay First Nation, Blood Tribe, Montana First Nation, Paul First Nation, Piikani Nation, Samson Cree Nation, Siksika Nation, Squamish Nation, Tsuut'ina Nation and Wesley First Nation.

Public Health and Safety
We seek to preserve public health and safety. It is our goal to maintain security for our employees and the peoples and communities where we operate.

We specifically look to minimize the following risks:

- Harm to people;
- Damage to property;
- Operational liability; and
- Loss of organizational reputation and integrity.

We work to prevent incidents and lower our risk by administering controls such as restricting physical access around and into our operating sites. The TransAlta Corporate Emergency Management program is in place to prepare employees for an emergency incident. Through this program, emergency preparedness training is implemented across our fleet in an all-hazards approach to public safety and emergency response. Each site also has an Emergency Response Plan and completes on-site drills and exercises specific to the incidents that could occur at each location. Our business continuity plan also helps prevent an interruption to operations. The program has corporate oversight and is supported by the Corporate Emergency Management Team in an emergency situation. The program has executive sponsorship and is focused on the protection of our people, assets, information and reputation.

Data and Digital Asset Protection
Our digital assets are also something we work hard to protect. Cybersecurity risks can include compromise of data integrity, hacking, social engineering, compromise of operations and infrastructure, credential breaches, attacks through third-party vendors and service providers, attacks involving artificial intelligence and machine learning, and cybersecurity staff turnover. Given the ever-evolving nature of cyber attacks, we are consistently adapting to address threats with a comprehensive cybersecurity program that consists of three pillars: technology, processes and resourcing. Each of these pillars can be reinforced independently to address specific cyber risks and threats. Through this program, TransAlta continually implements proactive controls and safeguards to mitigate the cybersecurity risks and threats posed to the organization.

Refer to the Governance and Risk Management - Cybersecurity Risk section of this MD&A for further details.

Stakeholder Relationships
Fostering relationships with our stakeholders is important to TransAlta. Driven by our values, we seek to maximize value creation for our stakeholders and TransAlta. We take a proactive approach to building relationships and understanding the impacts our business may have on local stakeholders.

TransAlta Stakeholders
To act in the best interests of the Corporation and to optimize the balance between financial, environmental and social value for both our stakeholders and TransAlta, we seek to:

- Engage regularly with stakeholders about our operations, growth prospects and future developments;
- Consider feedback and make changes to project designs and plans to resolve and/or accommodate concerns expressed by our stakeholders; and
- Respond in a timely and professional manner to stakeholder inquiries and concerns and work diligently to resolve issues or complaints.

Our stakeholders are identified through stakeholder mapping exercises conducted for each facility and prospective project development or acquisition. Through decades of stakeholder relations in the areas of our facilities, we have developed a strong understanding of who our stakeholders are and have gained understanding of our stakeholders' issues and concerns.

Our principal stakeholder groups are listed in the following table.

TransAlta Stakeholders

Non-governmental organizations (NGOs)	Community Associations and Organizations	Connecting Transmission Facility Operators
Regulators	Industry Organizations	Communities
Charitable Organizations/Non-profit	Standards Organizations	Retirees
All Levels of Government	Media	Residents/Landowners
Suppliers	Business Partners	Investor Organizations
Contractors	Unions/Labour Organizations	Financial Institutions
Government Agencies	Forest Associations/Industry	Mineral Rights Owners
System Operators	Oil & Gas Associations/Industry	Railroad Owners
Customers	Think Tanks	Utility Owners
Municipalities	Academics	PPA Buyers

Engagement Framework
Our stakeholder engagement framework is modelled after and closely tied to the stakeholder engagement aspect of ISO 14001, which is an internationally recognized environmental management standard. This framework is a streamlined corporate-wide approach to ensure that engagement and relationship-building practices are consistent across TransAlta's locations and types of work. Although we no longer certify under ISO 14001, we continue to operate within its established best practices.

Methods of Engagement
In order to run our business successfully, we maintain open communication channels with stakeholders. We commit to timely and professional resolution using values-based dialogue. We work internally and with each stakeholder to identify how to mitigate further issues.

Examples of our methods of engagement are listed in the following table.

Information & Communication	Dialogue & Consultation	Relationship Building
Open houses, town halls and public information sessions	In-person meetings with local groups and communities	Community Advisory Bodies
Newsletters, telephone conversations, emails and letters	Meetings with individual stakeholders e.g. landowners and residents	Capacity Agreements
Websites	Targeted audience sessions	Sponsorships and donations
Social media postings	Tours of our facilities and sites	Hosting events

A key focus of our work is to support the business growth through proactive engagement with stakeholders in all of our geographic operating areas in Australia, Canada and the US in order to develop and maintain relationships, assess needs and fit and to seek out collaborative and sustainable value creation opportunities. This helps ensure any stakeholder concerns are identified and can be addressed early in the development process, minimizing project delays. We conduct consultation primarily during project development and decommissioning and maintain engaged communication throughout operations. As an example, we implemented our stakeholder engagement program with stakeholders and Indigenous groups in connection with the proposed repowering at the Sundance and Keephills facilities. We filed our regulatory applications in December 2019, and our stakeholder engagement program will continue for the entire life cycle of the facilities.

Engagement Tracking and Reporting
Our Stakeholder and Indigenous Relations tracking program functions as an enterprise-wide communication recordkeeping tool, which is managed by our Stakeholder and Indigenous Relations team. This capacity fulfills our requirements for consultation with stakeholders and Indigenous groups alike, and is capable of producing regulatory reports as proof of engagement and consultation efforts. The tool can store email conversations, documents and voicemail messages related to any project, event or issue, and display them in a report format. It can also produce an array of statistical reports showing frequency and volume of engagement based on project, stakeholder, stakeholder group or keywords. This tracking program decreases the time and cost required to submit proof of engagement to government agencies.

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

Throughout 2019, representatives of the Board engaged extensively with the Corporation's significant shareholders. Specifically, since Jan. 1, 2019, the Board has met with 15 shareholders representing 42 per cent of the Corporation's total issued and outstanding common shares. In addition, in Sep. 2019, TransAlta held an Investor Day at which we provided detailed information about the Corporation's strategies, plans, operations and past, present and expected performance. The Investor Day afforded shareholders the opportunity to engage with the Corporation's senior management.

Customers
As one of the largest Alberta electricity generators providing energy services, our team serves businesses with:

- Energy consumption and cost management solutions;
- Market price risk and volume exposure mitigation;
- Sustainability initiatives such as self-generated electricity and environmental attributes (such as carbon offsets); and
- Monitoring of energy market design changes, price signals and applicable and available incentives.

The Customer Solution team at TransAlta has maintained a large portfolio of customers in Alberta across a broad range of industry segments including: commercial real estate, municipal, manufacturing, industrial, hospitality, finance and oil and gas. TransAlta is proud of the service we provide to our customers, which is evidenced by the achievement of over 90 per cent customer retention for the last three years.

We are focused on helping our customers in ways uniquely suited to achieve their sustainability goals. One example is through TransAlta's fleet of on-site cogeneration facilities. Cogeneration is the process of generating electricity and steam simultaneously. When constructed on-site, the construction of additional transmission lines is not required, which avoids disruption to the environment. It also reduces the natural gas required for some industrial processes by using high efficiency steam production rather than boilers. Examples of industrial processes that utilize cogeneration include gas processing, steam-assisted gravity drainage oil sands extraction, chemical manufacturing, and pulp and paper production. Cogeneration is recognized by regulatory bodies for its efficiency in generating power versus traditional methods, and thus can potentially produce Emission Performance Credits that can be used to satisfy our customers' regulatory obligations or sold as additional revenue.

We provide on-site generation for large mining and industrial customers. This requires us to be continually engaged with these customers to ensure that current electricity requirements are provided safely, reliably and cost effectively, but also that their future electricity requirements be satisfied alongside the benefits of lower GHG emissions.

Another way we can contribute to our customers' sustainability goals is through the use of environmental attributes. Environmental attributes that we have the ability to generate, trade, purchase and sell, include: EPCs, Alberta carbon offsets, Renewable Energy Credits ("RECs") and emission offsets. Alberta carbon offsets can be voluntarily generated by Alberta projects, which meet Alberta carbon offset system qualification protocols. Our Alberta wind facilities generate Alberta carbon offset credits. RECs are produced from our renewable energy assets (wind, hydro and solar) and can be traded in voluntary carbon markets or sold to customers. RECs can be used to meet regulatory requirements when a target for renewable energy generation is set by a jurisdiction or can be used to voluntarily 'green' electricity procurement. Emissions offsets are produced from voluntary projects that reduce emissions in sectors of the economy not covered by carbon reduction regulations. The optimization of environmental attributes can be used as a cost-effective way, for the Corporation or our customers, to lower compliance costs attributed to carbon policies or renewable portfolio standards, or utilized to achieve voluntary corporate sustainability or carbon reduction goals.

To learn more, please visit our website at www.transalta.com/customers.

Supply Chain
We continue to seek solutions to advance supply chain sustainability. In 2017, we optimized our global supply chain management operations by implementing a platform that supports increasing supply chain efficiency, reducing lead times, lowering costs and improving supplier performance. As we explore major projects, we assess vendors both at the evaluation stage and as part of information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example, getting information on:

- Estimated value of services that will be procured though local Indigenous businesses;
- Estimated number of local Indigenous persons that will be employed;
- Understanding overall community spend and engagement; and
- Understanding the state of community relations through interview processes and stakeholder work.

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

Community Investments
In 2019, TransAlta contributed approximately $2.1 million in donations and sponsorships (2018 - $2.4 million). One of our significant community investments each year is to United Way campaigns across Canada and the US. This year, TransAlta employees, retirees, contractors and the Corporation raised over $1.2 million for the United Way.

In 2019, we continued to focus our community investment on priority areas for TransAlta, including environment, education and leadership, health and human services, and arts and culture. Some of our partnerships included:

- Indspire – Through our new partnership with Indspire in 2019, TransAlta was able to almost double the number of bursaries available for Indigenous students through Indspire's matching program. There were 14 bursaries awarded in 2019. Formerly the National Aboriginal Achievement Foundation, Indspire is Canada's national charity for Indigenous education;

- Mother Earth's Children's Charter School - Located in treaty six territory, near Stony Plain, Alberta and our Alberta coal operations, Mother Earth Children's Charter School ("MECCS") has become an important part of TransAlta's community investment program. MECCS offers Kindergarten to Grade 9 and is cited as Canada's first and only Indigenous children's charter school. The school was established in 2003 to help provide Indigenous students with an education based strongly on cultural context rather than a traditional western educational model. Approximately 95 per cent of MECCS students are of Indigenous ancestry, with students coming from Paul First Nation, Enoch Cree Nation, Alexis Nakota Sioux Nation, Alexander First Nation, Alberta Beach, Stony Plain and Edmonton. The student population is diverse and includes Métis, Cree, Nakota Sioux and Stoney. Beginning in 2014, TransAlta has made an annual $35,000 donation to the school. In addition, each year at Christmas, TransAlta staff purchase Christmas presents for the students. Volunteers from TransAlta travel to the school to deliver the gifts providing both our employees and the students the opportunity to engage with each other;

- The Calgary Stampede – Founded in 2017, the TransAlta Performing Arts Studio at Stampede Park continues to provide a year-round facility for Calgary Stampede Foundation and Calgary's youth performing arts groups to rehearse, train and celebrate the arts;

- Southern Alberta Institute of Technology ("SAIT") – Working with SAIT, TransAlta continued to support Indigenous access to education through our Indigenous funding program that addresses a gap in federal and provincial funding for Indigenous academic upgrading;

- TransAlta Tri-Leisure Centre - TransAlta continues to be a proud sponsor of this facility. The TransAlta Tri-Leisure Centre is a sporting and recreation destination for many active and involved residents from the communities of Parkland County, Spruce Grove and Stony Plain in Alberta. At the facility, thousands of local residents, and many of our employees, participate in a wide range of sporting and cultural activities and join together in many community causes;

- Banff Centre – TransAlta continued its financial support for the Indigenous Leadership Program at the Banff Centre for Arts and Creativity. Over the past five years, TransAlta's support has provided 45 bursaries for members of Indigenous communities to attend programs across Alberta and British Columbia; and

- Energy Transition Support - On July 30, 2015, in Washington State, we announced a US$55 million community investment over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives. The US$55 million community investment is part of the TransAlta Energy Transition Bill passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State by closing the Centralia facility's two units, one in 2020 and the other in 2025. In order to invest the $55 million, three funding boards were formed: The Weatherization Board ($10 million), the Economic & Community Development Board ($20 million) and the Energy Technology Board ($25 million). To date, the Weatherization Board has invested $5.9 million, the Economic & Community Development Board $12 million and the Energy Technology Board $3.9 million. Specific projects that the boards funded in 2019 include rebuilding a playground (which included the installation of energy-efficient lighting and accessible surfaces and walkways), the construction of a training facility at Centralia College and funding Washington State's first electric school bus.

Natural Capital

We continue to increase financial value from natural or environmental capital-related business activities, while reducing our environmental footprint and potential risk factors related to environmental impacts. Comparable EBITDA from renewable energy generation in 2019 was $341 million (2018 - $342 million). Our revenue in 2019 from environmental attribute sales was $27.6 million (2018 - $21.6 million). In addition, in 2019 the sale of coal byproducts and waste-related recycling generated financial value in the range of $25 million to $35 million.

The following are key trends in our natural capital:

Year ended Dec. 31	**2019**	2018	2017
Renewable energy comparable EBITDA	**341.0**	342.0	289.0
Environmental attribute sales revenue	**27.6**	21.6	27.7
GHG emissions (million tonnes CO_2e)	**20.6**	20.8	29.9

Natural Capital Management

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in renewable energy resources such as wind, hydro and solar, we also believe that natural gas will continue to play an important role in meeting energy needs as part of a clean electricity transition. Natural gas plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. TransAlta operates simple and combined-cycle natural gas units and cogeneration facilities. We are planning to convert our Alberta coal units to natural gas in the 2020 to 2025 time frame, and by the end of 2025, our generation mix will be only from natural gas and renewable energy.

Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost and reliable electricity. The Corporation endeavours to be environmentally responsible and recognizes that the competitive pressures for economic growth and cost efficiency must be integrated with sound sustainability management, including environmental stewardship. The Corporation is subject to environmental laws and regulations that affect aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances. The Corporation's activities have the potential to impair natural habitat, damage vegetation and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require the Corporation to obtain and comply with a variety of environmental registrations, licenses, permits and other approvals. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Corporation. Currently the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (pollutants, metals) and energy use. Other material impacts that we manage and track performance on via our environmental management systems include environmental incidents and spills, land use, water use and waste management.

Environmental Governance

TransAlta's Governance, Safety and Sustainability Committee assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations and public policy changes and the establishment and adherence to environmental, health and safety practices, procedures and policies. More details on governance can be found in our Governance and Risk Management section of this MD&A.

Environmental Management Systems

All of our 73 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely align with the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for over 20 years, and our systems and knowledge of management systems are therefore mature. Only two facilities do not have ISO 14001 aligned EMS in place, although these facilities do have a comparable EMS in place. This is due to commercial arrangements (TransAlta is not the operator of those two sites). Aligning with ISO 14001 provides assurance that our systems are designed to continuously improve performance.

Environmental Performance

Reducing the environmental impact of our activities benefits not only our operations and financial results, but also the communities in which we operate. We expect that increased scrutiny will be placed on environmental management and compliance, and we therefore have a proactive approach to minimizing risks to our results. Our Board provides oversight with respect to the Corporation's monitoring of environmental regulations and public policy changes and to the establishment and adherence to environmental practices, procedures and policies in response to legal/regulatory and industry compliance or best practices.

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

Renewable Energy and Battery Storage
Since 2005, we have added approximately 1,300 MW in renewable energy capacity. We continue to operate over 900 MW of hydro energy and our experience with hydro operations spans over 100 years. In 2015, we made our first solar investment in a 21 MW solar facility in Massachusetts, and we continue to look for opportunities to develop and operate solar energy. Our production from renewable energy in 2019 offset the equivalent of approximately 1.6 million tonnes of carbon dioxide equivalent, or the removal of approximately 340,000 cars from the roads in 2019.

In 2020, we will commission the first utility-scale battery storage project in Alberta, located at our Summerview Wind Farm. The project will use Tesla battery technology and will have a capacity of 10 MW.

Natural Gas
Natural gas plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. TransAlta operates simple cycle, combined-cycle, and cogeneration facilities in Canada and Australia. Natural gas facilities provide highly efficient electricity and, in the case of cogeneration, steam production, directly to customers and for the wholesale markets. TransAlta is a significant operator of natural gas electricity in Canada and Australia.

Coal Transition
Our coal-to-gas conversion plan in Alberta is expected to significantly reduce our environmental footprint. As a result of our coal-to-gas conversions, energy use, GHG emissions, air emissions, waste generation and water usage are expected to significantly decline. Conversion of coal-fired power generation to gas-fired generation will eliminate all mercury emissions, the majority of particulate and sulphur dioxide emissions ("SO_2") as well as significantly reducing our nitrogen dioxide emissions ("NO_x"). Converting GHG-intensive coal facilities to natural gas will support significant reductions in GHGs (approximately 40 per cent reduction), while supporting reliability, affordability and growth of renewable electricity in Alberta. Converted coal facilities will use lower carbon natural gas (new methane reduction regulations on flaring and venting will reduce GHG emissions for natural gas producers) while supporting our local gas producers through the use of up to 700,000 GJs of natural gas per day.

Environmental Incidents and Spills
Protecting the environment and minimizing our impact to the environment supports healthy ecosystems and mitigates our environmental compliance risk and reputational risk. We maintain procedures for environmental incidents similar to our safety practices, with tracking, analyzing and active management to minimize occurrences. With respect to biodiversity management (management of ecosystems, natural habitats and life in the areas we operate), we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities and closely monitor the air, land and water in these areas to identify and curtail potential impacts.

Environmental incidents are separated into two categories: significant environmental incidents and regulatory non-compliance environmental incidents. We define regulatory non-compliance environmental incidents as events that involved a non-compliance event but did not have an impact on the environment. For example, a technical issue with a computer system for gathering real-time data could cause us to be out of compliance with local regulation or our EMS, but there is no direct consequence for the physical environment. All other events are captured as significant environmental incidents and these are where we deem there to be a material impact to the environment. In 2019, we recorded three significant environmental incidents (2018 - one incident). We recorded six non-compliance environmental incidents in 2019 (2018 - six incidents).

Our three significant environmental incidents in 2019 occurred at two of our wind facilities in the US. At our Lakeswind wind facility in Minnesota, we discovered a bald eagle mortality. At our Wyoming wind facility, we discovered two golden eagle mortalities. Root cause analysis investigations were performed on each eagle mortality and we found no causal factors or root causes related to human behaviour or equipment failure being involved in the incidents. These incidents were unusual and we have not had an eagle mortality across our wind fleet since 2015. For all incidents we collaborated with authorities and there were no enforcement actions in respect of such mortalities. Despite inconclusive findings, in order to reduce the risks of future impacts to protected eagle species, we are working on indirect corrective actions that include reviewing the potential for an updated bird monitoring study to be conducted at Lakeswind and Wyoming wind or other at-risk sites.

The following are the significant environmental incidents by fuel types:

Year ended Dec. 31	2019	2018	2017
Coal	—	1	1
Gas and renewables	**3**	—	1
Total significant environmental incidents	**3**	1	2

The following outlines regulatory non-compliance environmental incidents by fuel types:

Year ended Dec. 31	2019	2018	2017
Coal	**3**	4	3
Gas and renewables	**3**	2	—
Total regulatory non-compliance environmental incidents	**6**	6	3

We also continue to track and manage all non-reportable (minor) environmental incidents, which helps us identify what causes an incident. Understanding the root cause of incidents helps with incident prevention planning and education.

Typical spills that could occur at our operation sites are hydrocarbon spills. Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare that we experience large spills, which would adversely impact the environment and the Corporation. Spills that do occur are always addressed with a critical time factor. The estimated volume of spills in 2019 was 530 m^3 (2018 - 5 m^3). Spill volumes in 2019 were higher due to a 527 m^3 spill at our Sarnia cogeneration facility. This was not a traditional product spill and was a wastewater effluent limit exceedance from a sump. There was no enforcement action associated with this spill.

Air Emissions
Our coal facilities emit a number of air emissions that we track, analyze and report to regulatory bodies. We also work on mitigation solutions depending on the type of air emission. We report our major air emissions from coal, which includes NO_x, SO_2, particulate matter and mercury. We will continue to reduce air emissions in our existing fleet through our conversion and retirement of coal units in Alberta and Washington State. We are well underway and remain on track to achieve our target of 95 per cent SO_2 emission reductions over 2005 levels by 2030. Since 2005, we have reduced SO_2 emissions by 77 per cent. As noted above, we are on track to achieve our SO_2 target by 2025, well ahead of our 2030 goal. This allows flexibility as we convert coal facilities to natural gas and expand our natural gas fleet. We continue to model and evaluate this target to ensure a balance of growth and appropriate air emission reductions. We continue to capture 80 per cent of mercury emissions at our coal plants and by 2025, mercury emissions will be eliminated following the coal-to-gas conversions. Particulate matter and SO_2 emissions will also be virtually eliminated or considered negligible.

None of our Alberta coal facilities are located within 50 kilometres of dense or urban populations, but our Centralia coal facility in Washington State is 40 kilometres from a dense or urban population. As per guidance from SASB, "a facility is considered to be located near an area of dense population if it is located within 49 kilometres of an area of dense population" (being deemed to be a "minimum population of 50,000 persons"). The Centralia facility has two units and we are retiring one unit at the end of 2020 and the additional unit at the end of 2025, at which time air emissions from our coal facilities will be eliminated.

Our gas facilities emit low levels of NO_x that triggers reporting obligations to national regulatory bodies. These gas facilities also produce trace amounts of SO_2 and particulate matter, but at levels that are deemed negligible and do not trigger any reporting requirements or compliance issues. Many of our gas facilities are located in very remote and unpopulated regions, away from dense urban areas. Our Sarnia, Windsor, Ottawa and Fort Saskatchewan gas facilities are our only facilities with air emissions within 49 kilometres of dense or urban environments.

Our total air emissions in 2019 decreased compared with 2018 levels. Specifically, NO_x was reduced eight per cent, mercury was reduced three per cent, particulate matter was reduced one per cent and SO_2 was reduced 18 per cent over 2018 levels. Reduction in most emissions were largely due to an increase in co-firing (gas and coal) at our Alberta thermal facilities. Particulate matter emissions were adjusted historically to reflect our estimation on the level of PMs from road dust at our Alberta mining operations. We continue to mature our ability to estimate this data in line with guidance from Government of Canada.

Year ended Dec. 31	2019	2018	2017
Sulphur dioxide (tonnes)	**15,900**	19,300	36,200
Nitrogen dioxide (tonnes)	**25,800**	28,000	44,400
Particulate matter (tonnes)	**8,200**	8,400	11,400
Mercury (kilograms)	**60**	70	110

Water

Our principal water use is for cooling and steam generation in our coal and gas plants, but our hydro operations also require water flow for operations. Water for coal and gas operations is withdrawn primarily from rivers where we hold permits to withdraw water and must adhere to regulations on the quality of water that is discharged. The difference between withdrawal and discharge, representing consumption, is due to several factors, which includes evaporation loss and steam production for customers. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2019 we withdrew 286 million m^3 (2018 – 245 million m^3) and returned approximately 218 million m^3 (2018 – 208 million m^3) back to its source or 76 per cent. Overall water consumption was 68 million m^3 (2018 – 37 million m^3). Water withdrawal and consumption was much higher in 2019 due to increased production at our Centralia coal facility. Production was up 1,787 GWh in 2019 compared to 2018, due mainly to higher merchant pricing in the first half of 2019 and timing of dispatch optimization.

Our historical 2017 water from environment volume was revised in 2019 as a result of an adjustment to water volumes from our South Hedland facility. South Hedland began commercial operations in 2017 and water data was reported in an incorrect unit. This adjustment resulted in our 2017 water from environment changing from 213 m^3 to 211 m^3. Subsequently, water consumption (water from environment minus water to environment) also changed as a result and was revised from 41 m^3 to 39 m^3.

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

Year ended Dec. 31	2019	2018	2017
Water withdrawal	**286**	245	211
Water discharge	**218**	208	172
Total water consumption	**68**	37	39

Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customer). The facility operates as a once-through non-contact cooling system for our steam turbines. This means large amounts of water flow in and out of the system, as opposed to more advanced technology, which recycles water in cooling towers (more of a closed system). Despite large withdrawals from the adjacent St. Clair River to support our Sarnia operations, we return approximately 93 per cent of the water withdrawn. Water from this source is currently at "low risk" as per analysis from the SASB-endorsed Aqueduct Water Risk Atlas tool.

The Aqueduct Water Risk Atlas tool also highlights that water risk is high at our interior and southern Western Australia facilities due to high interannual variability in the region. Interannual variability refers to wider variations in regional water supply from year to year. Our water supply at these facilities is provided at no cost under PPAs with our mining customers, hence our risk is significantly mitigated. In addition, conservation and re-use strategies aimed at recycling water for mining operational needs have been developed. All water used in the region is sourced from scheme water, and with gas and diesel turbine water use, water wash techniques and frequency of activities are continually modified to minimize consumption and environmental impact. At the South Hedland facility in Western Australia, water risk is also high due to the risk of flooding in the region. The South Hedland facility was built above normal flood levels to mitigate potential risk from flooding. During a recent category 4 cyclone event in the area and associated flooding in the region, the South Hedland facility stayed dry and continued to generate power for the region. In addition, the South Hedland facility has developed a Water Efficiency Management Plan with Water Corporation WA, the principal supplier of water, wastewater and drainage services in Western Australia. Initiatives are aimed at reducing water consumption and costs through innovative technology and efficiencies identified through plant management.

In southern Alberta, following the flood of 2013, our hydro facilities are being used for a greater water management role than they have played in the past. In 2016, we signed a five-year agreement with the Government of Alberta to manage water on the Bow River at our Ghost reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis Lakes System (which includes Interlakes, Pocaterra and Barrier) for drought mitigation efforts.

Land Use
The largest land use associated with our operations is for surface mining of coal. Of the three mines we have operated, the Whitewood mine in Alberta is completely reclaimed and the land certification process is ongoing. Our Centralia mine in Washington State is currently in the reclamation phase and we have adopted a target to fully reclaim this mine by 2040. Our Highvale mine in Alberta is actively mined with certain sections undergoing reclamation. Our reclamation plans at Highvale are set out on a life-cycle basis and include contouring disturbed areas, re-establishing drainage, replacing topsoil and subsoil, re-vegetation and land management. Our mining practice incorporates progressive reclamation where the final end use of the land is considered at all stages of planning and development.

In 2019, we reclaimed 114.9 acres (46.5 hectares) at our Highvale mine, which was above our target of 110 acres (45 hectares). We also reclaimed 160.6 acres (65 hectares) of land at our Centralia mine.

Across our mining operations, to date we have reclaimed approximately 12,000 acres (4,800 hectares), which is approximately 38 per cent of land disturbed. Since 1991, we have planted approximately 2.5 million trees as part of this reclamation work.

Waste
In 2019 our operations generated approximately 1.5 million tonnes of primarily non-hazardous waste (2018 - 1.6 million tonnes). Only 0.1 per cent of waste volumes are hazardous materials. In 2019, only 0.1 per cent of waste was directed to landfill. From the remaining 99.9 per cent, 50 per cent was returned to the mine (ash from coal combustion), 49 per cent was reused and the remaining 0.4 per cent was recycled. Historical 2018 waste volumes were revised in 2019 due to misreported volumes of ash disposal from our Keephills facility.

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

Energy Use
TransAlta uses energy in a number of different ways. We burn coal, gas and diesel to generate electricity. We harness the kinetic energy of water and wind to generate electricity. We also generate electricity from the sun. In addition to combustion of fuel sources, we also track combustion of gasoline or diesel in our vehicles and the electricity use and fuel use for heating (such as natural gas) in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies. As an electricity generator, we continually and consistently look for ways to optimize or create efficiencies related to the use of energy. As an example, in 2019 we supported a study conducted by Stanford University to understand how to improve wind production. The research showed that angling turbines slightly away from the wind can boost energy produced and even out variable supply. Our coal-to-gas converted plants are also expected to see a reduction in total energy use, as the utilization of these plants is expected to be lower than historical utilization levels.

The following captures our energy use (millions of gigajoules). Energy use declined by four per cent over 2018 primarily as a result of reduced power production (lower plant utilization) at Alberta thermal.

Year ended Dec. 31	**2019**	2018	2017
Coal	**296.0**	309.8	447.4
Gas and renewables	**49.1**	48.6	49.4
Corporate	**0.1**	0.1	0.1
Total energy use	**345.2**	358.5	496.9

Weather
Abnormal weather events can impact our operations and give rise to risks. Due to the nature of our business, our earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar farm. Variations in weather may be impacted by climate change resulting in sustained higher temperatures and rising sea levels, which could have an impact on our generating assets. Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on wind turbine blades depends on a number of factors, including temperature and ambient humidity. The accumulation of ice on wind turbine blades can have a significant impact on energy yields, and could result in the wind turbine experiencing more downtime. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production. In addition, climate change could result in increased variability to our water and wind resources.

Our generation facilities and their operations are exposed to potential damage and partial or complete loss, resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures and other events beyond our control. Climate change can increase the frequency and severity of these extreme weather events. The occurrence of a significant event that disrupts the operation or ability of the generation facilities to produce or sell power for an extended period, including events that preclude existing customers from purchasing electricity, could have a material adverse effect on us. Our generation facilities could be exposed to effects of severe weather conditions, natural or man-made disasters and other potentially catastrophic events such as a major accident or incident at our sites. In certain cases, there is the potential that some events may not excuse us from performing our obligations pursuant to agreements with third parties. The fact that several of our generation facilities are located in remote areas may make access for repair of damage difficult. Refer to the Governance and Risk Management section of this MD&A for further discussion on weather-related risk.

During the past five years, deviations from expected weather patterns had the following impacts on our annual financial results:

- Warm weather in Alberta in 2015 increased derates at our coal facilities due to its impact on the Sundance cooling ponds. These cooling ponds are susceptible to warm weather; however, we anticipate that decreased coal production from the retirement of Sundance Units 1 and 2, respectively, in the medium term will reduce the stress from such occurrence; and
- Our Highvale mine in Alberta was subjected to significant rain starting in August 2016, which resulted in several weeks of flooding and threatened our coal deliveries. We focused on improving drainage infrastructure and using stockpiles to mitigate future risks.

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

Key Messages
- The GSSC includes in its mandate that it will review guidelines and practices relating to environmental protection and the Corporation's plans with respect to environmental impact;
- Our strategy involves moving away from GHG-intensive coal and achieving 100 per cent clean energy by 2025, represented by renewables and gas;
- Our business is showing resilience to two degrees of global warming by reducing GHG emissions – we have a target to reduce 19.7 million tonnes of CO_2e by 2030 over 2015 levels. To date we have achieved 59 per cent of this target;
- We are well positioned to build renewable energy facilities and lower-carbon gas facilities to support customer sustainability goals to decarbonize; and
- We have reduced 21 million tonnes of CO_2e since 2005, which is a 50 per cent reduction over the time period.

Governance
The highest level of oversight on climate-change-related business impacts is at our Board level, specifically by the GSSC and the AFRC. Macro issues and opportunities such as coal GHG emissions and the phase-out of coal power generation, cost-competitiveness of renewable energy and customer preferences toward lower carbon energy have been at the forefront of strategic discussions with our executive and Board and reflected in our actions to move away from coal, establish a 2030 GHG reduction target and grow our generation capacity from renewable energy and gas.

Our GSSC has oversight of climate-related issues as noted in the GSSC Charter. The GSSC meets on a quarterly basis. One of the mandates of the GSSC Charter is to monitor and assess climate change risks and compliance with associated legislation and public reporting. The GSSC also reviews guidelines and practices relating to environmental protection, including the mitigation of pollution and climate change and considers whether the Corporation's policies and practices relating to the environment are being effectively implemented and advises regarding the development of policies and practices regarding climate change, greenhouse gas and other pollutants".

Strategy
TransAlta, and the electricity sector in general, is at the forefront of reducing GHG emissions, utilizing innovation with lower-carbon and zero-carbon solutions (e.g., renewable energy, natural gas, distributed power generation, battery storage etc.) and are showing a path to resiliency in a low-carbon world. In addition to climate resiliency, front of mind for TransAlta and our sector is reliability of electricity supply and affordability for customers. To support our own path to reduce our GHG footprint and ensure climate resiliency, we have a corporate goal to reduce our GHG emissions by 60 per cent by 2030 over 2015 levels, while growing renewable energy and natural gas. We believe natural gas plays a strong role in supporting grid reliability and supporting customer goals of affordability. Scenario modelling of our GHG target shows that meeting our GHG target aligns us, under many scenarios, with science-based target setting. We have not officially validated a science-based target, but continue to monitor and model our future performance with the Sectoral Decarbonization Approach from the Science Based Targets Initiative.

Our business units and operations consistently seek energy-efficiency improvements, opportunities to integrate clean combustion technologies and development of emissions offset portfolios to achieve emissions reductions at competitive costs. We seek investment in climate-change-related mitigation solutions, such as renewable energy development, where we can maximize value creation for our shareholders, local communities and the environment. Conversion of our large coal fleet to gas-fired generation highlights this approach, which will allow us to run our assets longer than the federally mandated coal retirement schedule. Our goals for undertaking such actions are to enhance value for our shareholders, ensure low-cost and reliable power and reduce our GHG impact.

Our investments and growth in renewable electricity are highlighted by our diverse portfolio of renewable energy-generating assets. We currently operate close to 2,400 MW of hydro, wind and solar power. In 2019, we completed construction and commercial operation of an additional 119 MW of wind generation in the US. Today our diversified renewable fleet makes us one of the largest renewable producers in North America, one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. Production from renewable electricity in 2019 resulted in avoidance of approximately 1.6 million tonnes of CO_2e, which is equivalent to removing over 620,000 vehicles from North American roads over the same year.

As previously noted, we seek to commoditize carbon through trading and the generation and sale of environmental attributes. Annual revenue generation from the sale of environmental attributes (Alberta carbon offsets and RECs) in 2019 was $28 million.

Risk Management
Climate change risks are monitored through our company-wide risk management processes and are actively managed. Climate change risks and opportunities are identified at the Board level, executive and management level, business unit level (coal, gas, wind, solar and hydro) and through our corporate function (e.g. government relations, regulatory, emissions trading, sustainability, commercial, customer relations and investor relations). The business unit and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board.

Climate change risks at the asset or business unit level are identified through our Environmental Management Systems, asset management function and systems, our energy and trading business, active monitoring, active participation/communication with stakeholders, liaison with our corporate function, active participation in working groups and more.

Our climate change risks are divided into two major categories: (1) risks related to the transition to a lower-carbon economy, and (2) risks related to the physical impacts of climate change.

1. Transition Risks

We seek to understand the impact on our business as the world shifts to a lower carbon society. We participate in ongoing decisions related to climate policy and regulation.

Policy and Legal Risks

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business. For further details, see below and the Governance and Risk Management section of this MD&A.

Canadian Federal Government

Federal Carbon Pricing on GHG

On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. The price began at $20 per tonne of CO_2e emissions in 2019, and will rise by $10 per year until reaching $50 per tonne in 2022. In 2022, there will be a review of the Output-Based Pricing Standard and other aspects of the GGPPA.

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

The OBPS regulates large emitters' carbon intensity by setting a sectoral performance standard (benchmark) of GHG emissions per unit of production (e.g. tonnes CO_2e/MWh) for electricity generators. Emitters exceeding the benchmark generate carbon obligations and those emitters that perform below the benchmark generate emission performance credits. Emitters can meet their obligations by reducing their emission intensity, buying carbon credits from others (offsets or emission performance credits) or making compliance payment to the government.

Other jurisdictions were compliant with the GGPPA so did not have the backstop mechanism imposed in 2019. These jurisdictions must file and have their carbon pricing programs approved annually. Over future annual compliance periods, if parts or all of a province's GHG regulations fall out of compliance with the GGPPA, the federal government will impose its backstop mechanisms.

Gas Regulation

On Dec. 18, 2018, the federal government published the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity. Under the regulations, new and significantly modified natural gas fired electricity facilities with a capacity greater than 150 MW must meet a standard of 420 tonnes CO_2e per gigawatt hour ("tonnes CO_2e/GWh") to operate. For units with a capacity between 25 MW and 150 MW, their standard was set at 550 tonnes CO_2e/GWh. Facilities with a capacity less than 25 MW have no standard.

Under the regulations, coal-to-gas conversions will also eventually have to meet a standard of 420 tonnes CO_2e/GWh. If the first year performance test after conversion meets certain emission standards it will not have to meet the 420 tonnes CO_2e/GWh standard for several additional years past the end of its useful life.

Coal Regulation

On Dec. 18, 2018, amendments to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* came into force under the *Canadian Environmental Protection Act*, 1999. The amended regulations will require coal units to meet an emission level of 420 tonnes CO_2e/GWh by the earlier of end-of-life under the 2012 regulations or Dec. 31, 2029.

Clean Fuel Standard

In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard ("CFS") to reduce Canada's GHG through the increased use of lower carbon fuels, energy sources and technologies. The objective of the regulation is to achieve 30 million metric tonnes of annual reductions in GHG emissions by 2030. The CFS will establish life-cycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. Under the proposed policy, coal combusted at facilities that are covered by coal-fired electricity regulations will be exempt from the regulation. Natural gas used for electricity production is currently expected to be included under the gaseous stream.

Consultation on the gaseous stream began in 2019 and will continue into 2020. Publication of the draft regulations for the gaseous stream will occur in late 2020 with final regulations expected in 2021. The gaseous stream regulation is currently expected to come into force by 2023. TransAlta continues to be engaged in the consultation process.

Alberta

Large Emitter Greenhouse Gas Regulations

On Jan. 1, 2018, the Alberta government transitioned from the *Specified Gas Emitters Regulation* ("SGER") to the *Carbon Competitiveness Incentive Regulation*. Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sectoral performance compliance standard. In 2019, the CCIR price was $30/tonnes CO_2e, and the electricity sector performance standard was set at 0.370 tonnes CO_2e/MWh and set to decline annually. All renewable assets that received offset crediting under the SGER continued to receive credits under CCIR on a one-to-one basis. All other renewable assets that did not receive offset crediting under SGER were able to "opt-in" under CCIR and received carbon crediting up to the electricity sector performance standard until CCIR's termination at the end of 2019. Once wind projects' offset crediting standard under the SGER protocol ends, these projects will also be able to opt-in under CCIR system and be credited up to the performance standard.

On Apr. 16, 2019, the United Conservative Party ("UCP") won the Alberta provincial election with a majority government. The UCP committed to move from the CCIR to a new regulation called the *Technology Innovation and Emissions Reduction* ("TIER") regulation. TIER replaced CCIR on Jan. 1, 2020. For the electricity sector, there were negligible changes between CCIR and TIER with renewable facilities continuing to receive crediting. The carbon prices for TIER in 2020 will remain at $30/tonnes CO_2e but Alberta has not yet confirmed future price increases in line with federal requirements. The performance standard benchmark remained at 0.370 tonnes CO_2e/MWh. A review of TIER is not expected until 2023.

Facilities with emissions above the set benchmark will need to comply with TIER by: i) paying into the TIER Fund; ii) making reductions at their facility; iii) remitting emission performance credits from other facilities; or iv) remitting emission offset credits.

As required by the GGPPA, the Alberta government filed the TIER program details with the federal government. TIER was passed by the Alberta government on Oct. 29, 2019 and on Dec. 6, 2019 the federal government accepted the TIER regulation as compliant with the GGPPA for 2020.

Federal Pollution Pricing Fuel Charge (Fuel Charge)

The new UCP government repealed the Alberta carbon levy on May 30, 2019. The federal government will replace the repealed carbon levy with the Fuel Charge on Jan. 1, 2020. Alberta TIER-covered facilities are exempt from the Fuel Charge.

British Columbia

Beginning Apr. 1, 2018, BC increased its carbon tax rate to $35/tonnes CO_2e and committed to raise the price $5 per year until it reaches $50 per tonne in 2021.

Ontario

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

Large Emitter Greenhouse Gas Regulations

The Canadian federal GGPPA requires provinces to have greenhouse gas regulations and prices in place that align with the federal GGPPA. On Oct. 23, 2019, the federal government announced that Ontario large emitters would be subject to the federal backstop OBPS regulation. All covered industry facilities with annual emissions over 50,000 tonnes CO_2e are automatically covered with an opt-in provision for those emitters between 10,000 and 50,000 tonnes CO_2e annually. Ontario large emitters are currently subject to the federal backstop OBPS regulation.

On July 4, 2019, the Government of Ontario released the final regulations for the provincial Greenhouse Gas EPS. The EPS establishes GHG emission limits on covered facilities. Large emitters generating over 50,000 tonnes CO_2e or more per year will be covered with an opt-in provision for those emitters between 10,000 and 50,000 tonnes CO_2e annually. The carbon emissions limit for electricity is set at 420 tonnes CO_2e/GWh. The program also provides a method that accounts for the carbon efficiency of cogeneration units. The federal government has not accepted the EPS as compliant with the GGPPA so the OPBS remains in force for reporting purposes for 2019 obligations.

Facilities with emissions above the set reduction requirements can comply by: i) buying excess emission units from the regulator; ii) making reductions at their facility; or iii) using emission performance units generated by facilities emitting below their emission intensity limit. The first compliance period under the EPS will begin on Jan. 1 in the year in which Ontario is removed from the list of provinces to which the federal OBPS applies. Ontario has submitted the EPS for federal review.

Federal Pollution Pricing Fuel Charge (Fuel Charge)
The federal government replaced the repealed Ontario carbon levy with the Fuel Charge on Jan. 1, 2019. Ontario facilities covered by OBPS are exempt from the Fuel Charge.

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

Massachusetts
The Solar Renewable Electricity Credit I (SREC I) program carved out from Massachusetts' Renewable Portfolio Standard (RPS) an initial quantity of 400 MW from small solar facilities of 10 MW or less. The initial SREC I program size was expanded and replaced by a lower-valued SREC II program. In 2018, the solar incentive program evolved into the current Solar Massachusetts Renewable Target Program that further reduced the incentive levels.

The initial SREC I program's volume target was achieved, and qualified projects under SREC I continue to generate SREC I credits for their first 10 years post-Commercial Operation Date. SREC I facilities then generate Class 1 RECs under the Massachusetts RPS for the remainder of their operational life.

Under Massachusetts' net metering program, qualified facilities connect with the local utility and generate net metering credits. Net metering credits offset the delivery, supply and customer charges and can be sold to customers from remote or on-site qualifying facilities. In 2016, the net metering program was updated to reduce the value of the net metering credits by reducing the offset to only energy costs. New projects are impacted once the net metering program volume reaches 1,600 MW. Existing facilities were grandfathered and continue to receive the full, original cost offset treatment for a period of 25 years from initial commercial operation.

Australia
On Dec. 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The AUD$2.55 billion ERF is the centrepiece of the Australian government's policy and provides a policy framework to cut emissions by five per cent below 2000 levels by 2020 and 26 to 28 per cent below 2005 emissions by 2030. The ERF's safeguard mechanism, commencing from July 1, 2016, is designed to ensure emissions reductions purchased by the Australian government through the ERF are not displaced by significant increases in emissions elsewhere in the economy. The ERF and its safeguard mechanism provide incentives to reduce emissions across the Australian economy.

The Australian government has also committed to develop a National Energy Productivity Plan with a target to improve Australia's energy productivity by 40 per cent between 2015 and 2030. The ERF is not expected to have a material impact on our Australian assets as a result of the Australian assets being primarily composed of gas-fired generation. In addition, on June 23, 2015, the federal Australian government also reformed the Renewable Energy Target ("RET") scheme. The RET should add at least 33,000 GWh of renewable sources by 2020. This would double the amount of large-scale renewable energy being delivered compared to current levels and result in approximately 23.5 per cent of Australia's electricity generation being sourced from renewable projects.

Technology Risks
Battery storage technology is an emerging risk to the large-scale power-generation model. Battery storage has the ability to enable greater adoption of renewables and result in a shift to a distributed power-generation model. We continue to evaluate battery storage for its financial viability, while monitoring the potential impact battery technology could have on natural gas power generation.

We have demonstrated upside in growing renewables and gas-powered generation. From 2000 to 2018, we have grown renewables capacity from approximately 900 MW to close to 2,400 MW.

Market Risks

Changing customer behaviour, reduced consumption and associated use of electricity could impact the demand for electricity; however, we believe this risk is mitigated somewhat by the global trend to increasingly electrify customer products, transport and more. Our low-carbon business model supports this type of future. Increased costs for natural gas supply from carbon pricing can impact us. Further discussion can be found in the Governance and Risk Management section of this MD&A. Use of renewable resources, such as the wind and sun, removes associated risk related to cost of supply.

Our Corporate function applies regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks pertaining to uncertainty in the carbon market and as a safeguard to anticipate future impacts of regulatory changes on facilities. This information is directed to the business unit level for further integration. Identified climate change risks or opportunities and carbon pricing are recognized in the annual TransAlta long-and medium-range forecasting processes. We capture economic profit through generation of environmental attributes (such as carbon offsets and RECs) and through our emission trading function, which seeks to commoditize and profit from carbon trading.

Reputation Risks

Consumer trends appear to be moving in favour of renewable and cleaner electricity, which may make hydrocarbon options decreasingly popular. We are invested in natural gas as it provides vital support to the electricity system and is a lower-carbon fossil fuel. We already invest significantly in renewable energy and natural gas.

2. Physical Risks

As we learn more about the physical risks associated with climate change, and weather risk in general, we seek to understand further both acute and chronic risk, which could materially impact value creation from our operations.

Acute Risks

The TransAlta South Hedland facility in Western Australia was built with climate adaptation in mind. The plant is designed to withstand a category 5 cyclone, which can frequent the northwest region of Western Australia. Category 5 is the highest cyclone rating. Floods, which can occur in the area, have been mitigated by constructing the facility above the normal flood levels. In 2019, a category 4 cyclone hit this facility. Operations were not impacted and we were able to continue generating electricity through the storm, despite wide-spread flooding and shutdown of the nearby port and associated business activities.

Chronic Risks

We have not identified any chronic physical risks that could impact our operations. However, we continue to further our understanding and integration of climate modelling into our long-term planning.

Greenhouse Gas Emissions: Metrics and Targets

In 2019, we estimate that 20.6 million tonnes of GHGs with an intensity of 0.75 tonnes per MWh (2018 - 20.8 million tonnes of GHGs with an intensity of 0.77 tonnes per MWh) were emitted as a result of normal operating activities. Our reduction in GHG emissions is primarily the result of co-firing with gas and lower production volumes at our merchant Alberta coal facilities.

Our 2019 GHG data is reported to a number of different regulatory bodies throughout the year for regional compliance and as a result, may incur minor revisions as we review and report data. Any revisions would be reported historically in future reporting. As per the Kyoto Protocol, GHGs include carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, nitrogen trifluoride, hydrofluorocarbons and perfluorocarbons. Our exposure is limited to carbon dioxide, methane, nitrous oxide and a small amount of sulphur hexafluoride. The majority of our estimated GHG emissions are comprised of carbon dioxide emissions from stationary combustion from coal and natural gas power generation. Emissions intensity data has been aligned with the "Setting Organizational Boundaries: Operational Control" methodology set out in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard developed by the World Resources Institute and the World Business Council for Sustainable Development. As per the methodology, TransAlta reports emissions on an operation control basis, which means that we report 100 per cent of emissions at facilities in which we are the operator. Emissions intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership.

The GHG Protocol Corporate Standard classifies a company's GHG emissions into three scopes. Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy. Scope 3 emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. Scope 1 emissions in 2019 were estimated to be 20.4 million tonnes CO_2e and account for 99 per cent of emissions reported. All of our scope 1 emissions (100 per cent) are reported to national regulatory bodies in the country in which we operate. This includes: Australia (National Greenhouse Gas Emission Reporting), Canada (GHGPR) and the US (EPA). Scope 2 emissions were estimated to be 0.2 million tonnes CO_2e. We estimate our scope 3 emissions to be in the range of six million tonnes.

The following are our GHG emissions broken down by business unit and by scope 1 and 2 in million tonnes CO_2e:

Year ended Dec. 31	**2019**	2018	2017
Coal	**18.1**	18.3	27.4
Gas and renewables	**2.5**	2.5	2.5
Total GHG emissions	**20.6**	**20.8**	**29.9**

Year ended Dec. 31	**2019**	2018	2017
Scope 1	**20.4**	20.6	29.7
Scope 2	**0.2**	0.2	0.2
Total GHG emissions	**20.6**	**20.8**	**29.9**

All of our reported 2019 and historical GHG emissions are verified by Ernst & Young to a level of limited assurance. An assurance statement can be found in the back of this Integrated Annual report. In addition, GHG emissions are verified to a level of reasonable assurance in locations where we operate within a carbon regulatory framework. In Alberta we verify GHG emissions through the TIER program and as a result 51 per cent of our total scope 1 emissions are also verified to a level of reasonable assurance. Our GHG emissions are calculated using a number of different methodologies depending on the technologies available at our facilities.

Our target is to reduce 60 per cent or 19.7 million tonnes of GHG emissions by 2030 over 2015 levels, which is line with UN Sustainable Development Goal Goal 13, Climate Action. Since 2015 we have reduced 11.6 million tonnes, which represents a reduction of 36 per cent. By 2030, we expect to have reduced close to 30 million tonnes over 2005 levels, after adjusting for any new growth over this period.

The following highlights our GHG emission reductions since 2005 and our targeted emissions in 2030 (in line with our GHG target). The actual GHG emissions for the Corporation in 2030 will vary from that presented below depending on, among other things, the growth of the Corporation, including its on-site generation business.

Year ended Dec. 31	**2030**	2019	2005
Total GHG emissions	**12.5**	20.6	41.9

In 2019, TransAlta maintained its scoring on the Carbon Disclosure Project Climate Change investor request. Our overall score was a B, which places us as ahead of most companies in North America. The average CDP score for North America was a C.

Intellectual Capital

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

Brand Recognition

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

We are a leader in sustainability – publishing our first sustainability report in 1994. We are the first company in Alberta to combine our sustainability report with our financial report and we have been recognized by EXCEL Partnership for demonstrating best-in-class examples in sustainability reporting. Being members of working groups such as the EXCEL Partnership, the Energy Sector Sustainability Leadership Initiative, Canadian Electricity Association Steering Committee and Future-Fit provides validation and support with our sustainability strategy. We are listed on many of these organizations' websites, which further increases awareness of our sustainability practices. In addition, in early 2020, TransAlta was one of 325 companies globally to be added to the Bloomberg Gender-Equality Index. We believe that as we continue to invest in and strengthen our sustainability initiatives, the association of the TransAlta brand with sustainability will increase.

Diversified Knowledge

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

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

Power-Generation Type	Operating Experience (years)
Hydro	108
Natural Gas	69
Coal	69
Wind	17
Solar	4

Innovation: Idea Generation and Project Management

As innovation continues to disrupt and advance the global marketplace, we believe that our business, employees, systems and processes must remain competitive, agile and adaptive. Project Greenlight has been a key driver in ensuring the Corporation continues to provide year-over-year improvements in these areas. The program is focused on bottom-up innovation, which means ideas are generated by employees. Emphasizing bottom-up innovation across the Corporation has resulted in a strong culture of idea generation, where employee ideas are developed and advanced into business cases, adhering to project management best practices to ensure the delivery and success of the initiative.

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

Innovation: Applied Technologies
TransAlta has been at the forefront of innovation in the power-generation sector since the early 1900s when we developed hydro assets. We have been an early adopter and developer of wind technology in Canada and are now one of the largest wind generators in the country. Today we run a Wind Control Centre that monitors, to the second, every wind turbine we operate across North America. In 2015, we made our first investment in solar technology with the purchase of a 21 MW solar facility in Massachusetts.

As we move towards our goal to be a leading clean power company in Canada by 2025, we continue to seek solutions to innovate and create value for investors, society and the environment. This is evidenced by our announcements of the accelerated coal-to-gas conversion plans, the expansion of our Kent Hills wind farm in New Brunswick, the 90 MW Big Level and 29 MW Antrim wind projects recently completed in the US and the 207 MW Windrise wind project in Alberta. We have also announced the construction of our SemCAMS Cogeneration Project. Cogeneration is recognized by regulatory bodies for its efficiency in generating power compared to traditional methods. It reduces the natural gas required for several industrial processes by using high-efficiency steam production rather than boilers. The distributed system also provides independence from the power grid and avoids the need to construct additional transmission lines.

Battery storage is another technology we are investing in. TransAlta will begin construction on Alberta's first utility-scale lithium-ion battery storage facility in March 2020, called WindCharger. This project is unique as it will use TransAlta's existing Summerview Wind Farm to charge the battery, allowing WindCharger to be a truly renewable battery energy storage system. The project will use Tesla technology and will have a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. TransAlta will receive co-funding for this project from Emissions Reduction Alberta. Commercial Operation for WindCharger will begin in June 2020. The potential exists for the expansion of this technology, and TransAlta is continually investigating the viability of battery storage at our various wind farm locations.

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

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

Data & Innovation
TransAlta created the Data & Innovation team in 2019 for the purpose of modernizing its data infrastructure and processes to take advantage of new opportunities in analytics and artificial intelligence. The Data & Innovation team is cross-functional, composed of data architects, data scientists, data analysts, software developers, engineers, project managers, and financial and systems analysts. The team focuses its efforts on the delivery and enhancement of TransAlta's Modern Data Architecture, the rapid delivery of data-driven applications, the design and implementation of machine learning and artificial intelligence models and the advancement of process automation through the Robotic Process Automation Centre of Excellence.

2019 Sustainability Performance

Sustainability Targets and Results

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

	Human and Intellectual	Results	Comments
1. Reduce safety incidents	Achieve an Injury Frequency Rate (IFR) below 0.43	Not Achieved	In 2019, our IFR was 0.58. We did not achieve our goal in 2019, but continue to evolve our safety culture and practice. In 2020 we will move away from IFR to strengthen our safety progress. In addition to reporting on TIF, we are also tracking Total Recordable Injury Frequency (TRIF). TRIF tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked. TRIF provides us with the opportunity to target and monitor our significant injuries. It is also an industry-recognized safety metric and allows us to compare and benchmark our safety performance to that of our peers.
	Achieve a Total Injury Frequency (TIF) rate below 1.58	Achieved	In 2019, we achieved a TIF of 1.12 compared to 1.91 in 2018. This decrease was a direct result of our back to basics approach with respect to safety. Specifically, we focused on hazard identification (including audits and inspections), housekeeping and improved contractor management practices across the fleet.

	Natural	Results	Comments
2. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below five	Not achieved	In 2019, we recorded nine environmental incidents, which was above our target. We continue to target progress in this area and have divided our environmental incident reporting for 2020 into two categories: significant environmental incidents and non-compliance environmental incidents. We define non-compliance environmental incidents as events that involved a non-compliance event but did not have an impact on the environment. In 2019 only three of our nine recorded environmental incidents had a direct environmental impact. Further information on these incidents can be found in the Environmental Incidents and Spills section in the Natural Capital section in this MD&A.
3. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 110 acres/year	Achieved	In 2019, as part of ongoing reclamation activities at our Highvale mine, we replaced 114.9 acres of topsoil.

4. Reduce air emissions	Achieve a 95 per cent reduction from 2005 levels of TransAlta SO_2 emissions and 50 per cent reduction in NO_x emissions by 2030	On track	We are well on track to achieve our target of 95 per cent emission reductions of SO_2 and NO_x by 2030. Since 2005, we have reduced NO_x emissions by 61 per cent and SO_2 emissions by 77 per cent. In 2019 we reduced approximately 2,000 tonnes of NO_x emissions and 3,500 tonnes of SO_2 emissions over 2018 levels.
5. Reduce GHG emissions Our GHG goal and targets support UN Sustainable Development Goal 13: Climate Action related to ensuring "integration of climate change measures into national policies, strategies and planning"	Our goal is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming (our GHG and clean power targets assume reasonably anticipated growth and operating scenarios)	On track	We are well on track to achieve our target of 60 per cent GHG emission reductions by 2030. Since 2015, we have reduced GHG emissions by 36 per cent. In 2019, we reduced approximately 0.2 million tonnes of CO_2e over 2018 levels.

	Social and Relationship	Results	Comments
6. Support quality education for youth Our education goal and target support UN Sustainable Development Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	Achieved	Support in 2019 included: provided bursaries to high school graduates through a partnership with Indspire, funded academic upgrading programs through SAIT, supported an Indigenous Leadership Program and maintained communication on employment opportunities through various mediums to support different access options for Indigenous communities.

	Comprehensive	Results	Comments
7. TransAlta will be a leading clean power company by 2025	Convert at least two coal units at Sundance, Alberta and three coal units at Keephills, Alberta to gas-fired generation between 2020 and 2023	On track	Progress in 2019 included: completed construction of our Pioneer Pipeline and transported our first gas to both Sundance and Keephills; agreed to purchase two 230 MW Siemens gas turbines to repower Sundance 5; and we announced our Clean Energy Investment Plan, which includes capital investments in our coal-to-gas conversions.
Our clean power goal and targets support the UN Sustainable Development Goal 7: Affordable and Clean Energy related to ensuring "access to affordable, reliable, sustainable and modern energy"	Aim that by 2025, 100 per cent of our owned net generation capacity will be from clean power (renewables and gas)	On track	We continued with our coal-to-gas transition plans in 2019, while announcing new renewable energy growth projects.
	Seek new opportunities to grow our renewable portfolio of 2,265 MW wind, hydro and solar assets	On track	In 2019, we announced an agreement to purchase a 49 per cent interest in the 136.8 MW Skookumchuk wind project

2020 Sustainable Development Targets

Our 2020 and longer-term sustainability targets support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas. We continue to evolve and adapt targets to focus on anticipated key areas of materiality to stakeholders. Targets are outlined below:

ESG Alignment: Environment		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Minimize fleet-wide environmental incidents	Keep annual significant environmental incidents below two and keep environmental regulatory non-compliance incidents below four	Future-Fit Target BE08: "Operations do not encroach on ecosystems or communities"
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	Future-Fit Target PP13: "Ecosystems are restored"
Reduce air emissions	By 2030, achieve a 95% reduction of SO_2 emissions and a 50% reduction of NO_x emissions below 2005 levels from TransAlta coal facilities	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
Reduce GHG emissions	By 2030, achieve company-wide GHG reductions of 60% below 2015 levels, in line with a commitment to the UN SDGs and prevention of 2ºC of global warming	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning"
ESG Alignment: Social		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Reduce safety incidents	Achieve a Total Injury Frequency rate below 1.17	UN SDG Target 8.8: "Protect labour rights and promote safe and secure working environments for all workers, including migrant workers, in particular women migrants, and those in precarious employment"
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	UN SDG Target 4.5: "By 2030, eliminate gender disparities in education and ensure equal access to all levels of education and vocational training for the vulnerable, including persons with disabilities, Indigenous peoples and children in vulnerable situations"
ESG Alignment: Governance		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Strengthen gender equality	Achieve a quota of 50 per cent female representation on the Board by 2030 Achieve at least 40 per cent female employment among all employees of the Corporation by 2030 Maintain equal pay for women in equivalent roles as men	UN SDG Target 5.5: "Ensure women's full and effective participation and equal opportunities for leadership at all levels of decision making in political, economic and public life"
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	UN SDG Target 12.6: "Encourage companies, especially large and transnational companies, to adopt sustainable practices and to integrate sustainability information into their reporting cycle"
ESG Alignment: Environment and Social		

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Leading clean power company by 2025	By the end of 2025, convert coal facilities to gas through boiler conversions and combined-cycle repowering	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
	No further coal generation by the end of 2025 and 100% of our owned net generation capacity will be from clean electricity (renewables and gas)	UN SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services"
	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	UN SDG Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix"

Governance and Risk Management

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

Governance

The key elements of our governance practices are:

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

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

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

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

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

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

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

The AFRC, consisting of independent members of the Board, provides assistance to the Board in fulfilling its oversight responsibility relating to the integrity of our consolidated financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration; independence; performance and reports; and the legal and risk compliance programs as established by management and the Board. The AFRC approves our Commodity and Financial Exposure Management policies and reviews quarterly Enterprise Risk Management reporting.

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

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

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

The IPC is empowered by the Board to oversee management's investment conclusions and the execution of major, Board-approved capital expenditure projects that further the Corporation's strategic plans. The IPC undertakes a number of actions that include: i) reviewing and considering the substantive risks, returns, financing and other key elements relating to the Corporation's major capital projects; ii) reviewing and assessing mitigation plans, expected outcomes, and implementation throughout the project life cycle with respect to substantive risks; iii) reviewing and assessing cost estimating methodologies employed throughout the project life cycle; iv) reviewing and assessing progress reports including periodic updates on the project schedule, risks and costs at key milestones as projects advance through to execution; v) reviewing post-project look-backs; and vi) reviewing and providing recommendations to the Board regarding capital expenditures associated with such capital projects.

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

The CEO and senior management review and report on key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity Risk and Compliance Committee, and weekly by the commodity risk team, the commercial managers in Trading and Marketing, and the Senior Vice-President Trading & Commercial.

The Investment Committee is chaired by our Chief Financial Officer and is comprised of the CEO, Chief Financial Officer, Chief Operating Officer and Chief Business Development Officer. It reviews and approves all major capital expenditures including growth, productivity, life extensions and major coal outages. Projects that are approved by the Committee will then be put forward for approval by the Board, if required.

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

The Hydro Operating Committee consists of two Brookfield members, with expertise in hydro facility management, and and two TransAlta members. This committee was formed in 2019 for the purpose of providing advice and recommendations to TransAlta's management and operational team on matters in connection with the operation, and maximizing the value, of TransAlta's Alberta Hydro Assets. It is delivering on its objectives by thoroughly reviewing the operating, maintenance, safety and environmental aspects of TransAlta's Alberta Hydro Assets and, following that

review, providing expert advice and recommendations to TransAlta's hydro operational team. The Committee has an initial term of six years, which can be extended for an additional two years.

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

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to, and respectful of, our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a code of conduct on an annual basis.

Reporting

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

Whistleblower System

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

Value at Risk and Trading Positions

Value at risk ("VaR") is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2019, associated with our proprietary commodity risk management activities was $1 million (2018 - $2 million). Refer to the Risk Factors - Commodity Price Risk section of this MD&A below for further discussion.

Risk Factors

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

A reference herein to a material adverse effect on the Corporation means such an effect on the Corporation or its business, operations, financial condition, results of operations and/or its cash flows, as the context requires.

For some risk factors we show the after-tax effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes in 2019. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk

Volume risk relates to the variances from our expected production. The financial performance of our hydro, wind and solar operations is highly dependent upon the availability of their input resources in a given year. Shifts in weather or climate patterns, seasonal precipitation and the timing and rate of melting and runoff may impact the water flow to our facilities. The strength and consistency of the wind resource at our facilities impacts production. The operation of thermal plants can also be impacted by ambient temperatures and the availability of water and fuel. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- Actively managing our assets and their condition in order to be proactive in plant maintenance so that our plants are available to produce when required;
- Monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities;
- Placing our facilities in locations we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require; and
- Diversifying our fuels and geography to mitigate regional or fuel-specific events.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	$8 million

Generation Equipment and Technology Risk

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

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

We manage our generation equipment and technology risk by:

- Operating our facilities within defined industry standards that optimizes availability over their commercial operating life;
- Performing preventive maintenance in accordance with applicable industry practices, major equipment supplier recommendations and our operating experience;
- Adhering to comprehensive maintenance programs and regular turnaround schedules;
- Adjusting maintenance plans by facility to reflect equipment type, age and commercial risk;
- Having adequate business interruption insurance in place to cover extended forced outages;
- Having clauses in our PPAs and other long-term contracts that allow us to declare force majeure in the event of an unforeseen failure;
- Selecting and applying proven technology in our generating facilities, where practical;
- Where technology is newer, ensuring service agreements with equipment suppliers include appropriate availability and performance guarantees;
- Monitoring our fleet against industry performance to identify issues or advancements that may impact performance and adjusting our maintenance and investment programs accordingly;
- Negotiating strategic supply agreements with selected vendors to ensure key components are readily available in the event of a significant outage;
- Entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts; and
- Implementing long-term asset management strategies that optimizes the life cycles of our existing facilities and/or identifies replacement requirements for generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage the financial exposure associated with fluctuations in electricity price risk by:

- Entering into long-term contracts that specify the price at which electricity, steam and other services are provided;
- Maintaining a portfolio of short, medium and long-term contracts to mitigate our exposure to short-term fluctuations in commodity prices;
- Purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit; and
- Ensuring limits and controls are in place for our proprietary trading activities.

In 2019, we had approximately 90 per cent (2018 - 85 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfil our supply obligations under these short and long-term contracts.

We manage the financial exposure to fluctuations in the cost of fuels used in production by:

- Entering into long-term contracts that specify the price at which fuel is to be supplied to our plants;
- Hedging emissions costs by entering into various emission trading arrangements; and
- Selectively using hedges, where available, to set prices for fuel.

In 2019, 66 per cent (2018 - 67 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 76 per cent (2018 - 85 per cent) of our purchased coal was contractually fixed.

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

Coal Supply Risk

Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities. At our coal-fired plants, input costs such as diesel, tires, the price and availability of mining equipment, the volume of overburden removed to access coal reserves, rail rates and the location of mining operations relative to the power plants are some of the exposures in our operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At US Coal, interruptions at our supplier's mine, the availability of trains to deliver coal and the financial viability of our coal suppliers could affect our ability to generate electricity.

We manage coal supply risk by:

- Ensuring that the majority of the coal used in electrical generation in Alberta is from reserves permitted through coal rights we have purchased or for which we have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties;
- Using longer-term mining plans to ensure the optimal supply of coal from our mines;
- Sourcing the majority of the coal used at US Coal under a mix of contract durations and from different mine sources to ensure sufficient coal is available at a competitive cost;
- Contracting sufficient trains to deliver the coal requirements at US Coal;
- Ensuring coal inventories on hand at Canadian Coal and US Coal are at appropriate levels for usage requirements;
- Ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner;
- Monitoring and maintaining coal specifications, and carefully matching the specifications mined with the requirements of our plants;
- Co-firing natural gas with coal;
- Monitoring the financial viability of US coal suppliers; and
- Hedging diesel exposure in mining and transportation costs.

Natural Gas Supply and Price Risk

Having sufficient natural gas and natural gas transportation services available so that we can blend natural gas in with coal at our Alberta thermal facilities, and for the ultimate conversion of those units to natural gas is essential to maintaining the reliability and availability of those facilities. Using natural gas at our coal-fired plants, and ultimately converting them to natural gas, allows us to reduce overall carbon emissions and costs, reduce the risk of coal opacity issues, and improves our operating and sustaining capital costs. Ensuring adequate pipeline transportation service and natural gas supply for our Alberta thermal units may be impacted by, among other things, the timing of receiving regulatory and other approvals for firm transportation commitments, weather-related events, work stoppages, system maintenance, variability in pipeline hydraulics pressure and flows, and impacts due to other naturally created events. Pricing of natural gas is driven by market supply and demand fundamentals for natural gas in North America and globally. We are exposed to changes in natural gas prices, which may impact the profitability of our facilities and how the facilities are dispatched into the market.

We manage gas supply and price risk by:

- Ensuring that we have at least two pipelines supplying the gas used in electrical generation in Alberta;
- Contracting for firm gas delivery and supply;
- Monitoring the financial viability of gas producers and pipelines;
- Hedging gas price exposure;
- Monitoring pipelines maintenance schedules and transportation availability; and
- Incorporating the ability to continue using coal in some of the units as the units transition from coal to 100 per cent natural gas.

Environmental Compliance Risk

Environmental compliance risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the US. We anticipate continued and growing scrutiny by investors and other stakeholders relating to sustainability performance. These changes to regulations may affect our earnings by reducing the operating life of generating facilities, imposing additional costs on the generation of electricity, such as emission caps or tax, requiring additional capital investments in emission capture technology or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental compliance risk by:

- Seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents;
- Having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety management system in place that is designed to continuously improve performance;
- Committing significant experienced resources to work with regulators in Canada and the US to advocate that regulatory changes are well designed and cost effective;

- Developing compliance plans that address how to meet or surpass emission standards for GHGs, mercury, SO_2, and NO_x, which will be adjusted as regulations are finalized;
- Purchasing emission reduction offsets;
- Investing in renewable energy projects, such as wind, solar and hydro generation; and
- Incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

We strive to be in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to the GSSC.

Credit Risk

Credit risk is the risk to our business associated with changes in the creditworthiness of entities with which we have commercial exposures. This risk results from the ability of a counterparty to either fulfil its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

We manage our exposure to credit risk by:

- Establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits and the credit concentration with any specific counterparty;
- Requiring formal sign-off on contracts that include commercial, financial, legal and operational reviews;
- Requiring security instruments, such as parental guarantees, letters of credit, and cash collateral or third-party credit insurance if a counterparty goes over its limits. Such security instruments can be collected if a counterparty fails to fulfil its obligation; and
- Reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as by requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2018. We had no material counterparty losses in 2019. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2019:

	Investment grade *(%)*	**Non-investment grade** *(%)*	**Total** *(%)*	**Total amount**
Trade and other receivables[1]	85	15	**100**	**462**
Long-term finance lease receivables	100	—	**100**	**176**
Risk management assets[1]	99	1	**100**	**806**
Loan receivable[2]	**—**	100	**100**	**47**
Total				**1,491**

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

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $5 million (2018 - $13 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our US-denominated debt. Our exposures are primarily to the US and Australian currencies.

Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

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

- Hedging our net investments in US operations using US-denominated debt;
- Entering into forward foreign exchange contracts to hedge future foreign-denominated expenditures including our US-denominated debt that is outside the net investment portfolio; and
- Hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year and 30 per cent in the fourth year. The US exposure will be managed with a combination of interest expense on our US-denominated debt and forward foreign exchange contracts and the Australian exposure will be managed with forward foreign exchange contracts.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that an average $0.03 increase or decrease in the US or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.03	$24 million

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to engage in trading and hedging activities, capital projects, debt refinancing and payment of liabilities, capital structure and general corporate purposes. Credit ratings facilitate these activities and changes in credit ratings may affect our ability and/or the cost of accessing capital markets, establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment. Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may impact our ability to enter into these contracts or any ordinary course contract, decrease the credit limits granted and increase the amount of collateral that may have to be provided. Certain existing contracts contain credit rating contingent clauses, that, when triggered, automatically increase costs under the contract or require additional collateral to be posted. Where the contingency is based on the lowest single rating, a one-level downgrade from a credit rating agency with an originally higher rating may not, however, trigger additional direct adverse impact.

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

As at Dec. 31, 2019, we have liquidity of $1.7 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2020.

We manage liquidity risk by:

- Monitoring liquidity on trading positions;
- Preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital;
- Reporting liquidity risk exposure for commodity risk management activities on a regular basis to the Commodity Risk & Compliance Committee, senior management and the AFRC;
- Maintaining a strong balance sheet; and
- Maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

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

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

- Employing a combination of fixed and floating rate debt instruments; and
- Monitoring the mixture of floating and fixed rate debt and adjusting to ensure efficiency.

At Dec. 31, 2019, approximately 11 per cent (2018 - 14 per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	20	$1 million before tax

Project Management Risk

On capital projects, we face risks associated with cost overruns, delays and performance.

We manage project risks by:

- Ensuring all projects follow established corporate processes and policies;
- Identifying key risks during every stage of project development and ensuring mitigation plans are factored into capital estimates and contingencies;
- Reviewing project plans, key assumptions and returns with senior management prior to Board of Director approvals;
- Consistently applying project management methodologies and processes;
- Determining contracting strategies that are consistent with the project scope and scale to ensure key risks, such as labour and technology, are managed by contractors and equipment suppliers;
- Ensuring contracts for construction and major equipment include key terms for performance, delays and quality backed by appropriate levels of liquidated damages;
- Reviewing projects after achieving commercial operation to ensure learnings are incorporated into the next project;
- Negotiating contracts for construction and major equipment to lock-in key terms such as price, availability of long lead equipment, foreign currency rates and warranties as much as is economically feasible before proceeding with the project; and
- Entering into labour agreements to provide security around labour cost, supply and productivity.

Human Resource Risk

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

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

We manage this risk by:

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

In 2019, 46 per cent (2018 - 50 per cent) of our labour force was covered by 10 (2018 - 10) collective bargaining agreements. In 2019, four (2018 - four) agreements were renegotiated. We anticipate the successful negotiation of six collective agreements in 2020.

Regulatory and Political Risk

Regulatory and political risk is the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market regulation and re-regulation, increased oversight and control, structural or design changes in markets, or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business. This risk includes, among other things, uncertainties associated with the development of a capacity market for electricity in Ontario, potential market bid mitigation in Alberta, uncertainties associated with the development of carbon pricing policies and the qualification of our renewable facilities in Alberta to generate tradable GHG allowances as part of the transition from the *Carbon Competitiveness Incentive Regulation* to the *Technology Innovation and Emissions Reduction* regulations.

We manage these risks systematically through our Legal and Regulatory groups and our Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electricity system operators and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design, and we engage in industry-and government-agency-led stakeholder engagement processes. Through these and other avenues, we engage in advocacy and policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments and regulatory agencies over the longer term.

International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk

Access to transmission lines and transmission capacity for existing and new generation is key to our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in markets in which we operate continue to increase because new connections to the power system are consuming transmission capacity quicker than it is being added by new transmission developments.

Reputation Risk

Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments and other entities.

We manage reputation risk by:

- Striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders;
- Clearly communicating our business objectives and priorities to a variety of stakeholders on a routine and transparent basis;
- Applying innovative technologies to improve our operations, work environment and environmental footprint;
- Maintaining positive relationships with various levels of government;
- Pursuing sustainable development as a longer-term corporate strategy;
- Ensuring that each business decision is made with integrity and in line with our corporate values;
- Communicating the impact and rationale of business decisions to stakeholders in a timely manner; and
- Maintaining strong corporate values that support reputation risk management initiatives, including the annual Code of Conduct sign-off.

Corporate Structure Risk

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and partnerships and the payment of funds by our subsidiaries and partnerships in the form of distributions, loans, dividends or otherwise. In addition, our subsidiaries and partnerships may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

Cybersecurity Risk

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

We continuously take measures to secure our infrastructure against potential cyberattacks that may damage our infrastructure, systems and data. TransAlta's cybersecurity model consists of three pillars: technology, processes and resourcing. Each of these pillars can be reinforced independently to address specific cyber risks and threats that are confronting TransAlta. Significant cyber risks that could pose a threat to TransAlta include phishing, ransomware, social engineering, supplier chain, commodity hostage, state sponsored, artificial intelligence, machine learning attacks and a high risk of cybersecurity employee turnover. Proactive controls and safeguards to mitigate cybersecurity risk and threats posed to the organization include:

- Leveraging in place technologies to restrict communication within TransAlta's networks thus limiting the ability for adversaries to achieve their aim;
- Partnering with a third-party cybersecurity specialty firm to outsource critical components of our cybersecurity program;
- Enhancing our policies and processes through the use of periodic reviews and table-top exercises;
- Maintaining an effective and robust cybersecurity awareness training and campaign;
- Integrating cybersecurity into our business processes and performing robust cybersecurity risk assessments; and
- Continuously improving our cybersecurity program to ensure it is effective in responding to and addressing cybersecurity risks.

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

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk, and counterparty risk.

Income Taxes

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

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

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

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

Legal Contingencies

We are occasionally named as a party in various disputes, claims and legal or regulatory proceedings that arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular dispute, claim or proceeding will be resolved in our favour or our liabilities with respect to such claims will not have a material adverse effect on us or our business, operations or financial results. Refer to the Other Consolidated Analysis section of this MD&A for further details.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during renewal of the insurance policies on Dec. 31, 2019. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims. All insurance policies are subject to standard exclusions. Cyber coverage is not currently purchased.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting (''ICFR'') and disclosure controls and procedures ("DC&P''). There have been no changes in our ICFR or DC&P during the year ended Dec. 31, 2019, that have materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

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

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under applicable securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and as such may not prevent or detect all misstatements, and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2019, the end of the period covered by this report, our ICFR and DC&P were effective.

Management's Report

To the Shareholders of TransAlta Corporation

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

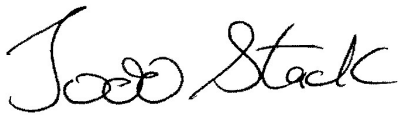
Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation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

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



Dawn L. Farrell
President and Chief Executive Officer

Mar. 3, 2020



Todd Stack
Chief Financial Officer

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

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

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

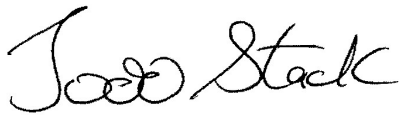
TransAlta proportionately consolidates the accounts of the Sheerness, Pioneer Pipeline and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2019 Consolidated Financial Statements of TransAlta included $359 million and $326 million of total and net assets, respectively, as of Dec. 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2019, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2019, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.



Dawn L. Farrell
President and Chief Executive Officer



Todd Stack
Chief Financial Officer

Mar. 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting
We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2019 and 2018, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated March 3, 2020 expressed an unqualified opinion thereon.

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

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

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

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations, which are included in the 2019 consolidated financial statements of TransAlta Corporation and constituted $359 million and $326 million of total and net assets, respectively, as of December 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada
March 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements
We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Corporation") as of December 31, 2019 and 2018, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows, for each of the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Adoption of IFRS 16
As discussed in Note 3 to the consolidated financial statements, the Corporation changed its method of accounting for leases in 2019 due to the adoption of *IFRS 16 - Leases*.

Report on Internal Control Over Financial Reporting
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 3, 2020 expressed an unqualified opinion thereon.

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

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

Critical Audit Matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Long-lived Assets within the US Coal segment & Goodwill related to the Wind and Solar segment

Description of the Matter

As disclosed in notes 2(I), (J), 7, 17, and 20 of the consolidated financial statements, the Corporation owns significant power generation assets which are required to be reviewed for indicators of impairment or impairment reversal at the cash generating unit ("CGU") level and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually. Long lived assets for the US Coal segment amount to $352 million. Goodwill related to the Wind and Solar segment amounts to $176 million.

We identified the assessment of indicators of impairment or impairment reversal for the CGUs within the US Coal segment as a critical audit matter because it involves auditing the judgment applied by management to assess various external and internal sources of information, more specifically if significant changes with an adverse effect on the Corporation have taken place during the year, or will take place in the near future, in the market or economic environment. Determining the recoverable amount for those CGUs for which indicators of impairment or impairment reversal are present within the US Coal segment, as well as determining the recoverable amount for the Wind and Solar segment for the purposes of the annual goodwill impairment test was also identified as a critical audit matter because it involves significant estimation with a high degree of subjectivity including forecasting future cash flows, generation profiles, and commodity prices, and determining the appropriate discount rate.

How We Addressed the Matter in Our Audit

We obtained an understanding of management's process for performing their assessment of indicators of impairment or impairment reversal and the estimation of the recoverable amount. We evaluated the design and tested the operating effectiveness of controls over the Corporation's processes to identify indicators and determine the recoverable amount. Our audit procedures to test the indicators assessment included, among others, evaluating the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. Our audit procedures to test the Corporation's recoverable amount of various CGUs included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical power generation data to evaluate future generation forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking against available market views.

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(Y)(IV) and 14 of the consolidated financial statements, the Corporation enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as Level III are determined using assumptions that are not readily observable. As at December 31, 2019 the Corporation's derivative financial instruments classified as level III were $686 million.

How We Addressed the Matter in Our Audit

Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future commodity prices, volatility, unit availability, demand profiles, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.

We obtained an understanding of the Corporation's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also utilized third-party data to test management's future pricing assumptions, credit valuation adjustments, and liquidity assumptions as well as comparing terms such as volumes and timing to executed commodity contracts. We performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of level III fair value. For a sample of new level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates.

Ernst & Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947
Calgary, Canada
March 3, 2020

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2019**	2018	2017
Revenues (Note 5)	**2,347**	2,249	2,307
Fuel, carbon compliance and purchased power (Note 6)	**1,086**	1,100	1,016
Gross margin	**1,261**	1,149	1,291
Operations, maintenance and administration (Note 6)	**475**	515	517
Depreciation and amortization	**590**	574	635
Asset impairment charge (Note 7)	**25**	73	20
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	**(88)**	—	—
Taxes, other than income taxes	**29**	31	30
Termination of Sundance B and C PPAs (Note 4(E))	**(56)**	(157)	—
Net other operating income (Note 9)	**(49)**	(47)	(49)
Operating income	**335**	160	138
Finance lease income	**6**	8	54
Net interest expense (Note 10)	**(179)**	(250)	(247)
Foreign exchange loss	**(15)**	(15)	(1)
Gain on sale of assets and other (Note 4(D) and 17)	**46**	1	2
Earnings (loss) before income taxes	**193**	(96)	(54)
Income tax expense (recovery) (Note 11)	**17**	(6)	64
Net earnings (loss)	**176**	(90)	(118)
Net earnings (loss) attributable to:			
TransAlta shareholders	**82**	(198)	(160)
Non-controlling interests (Note 12)	**94**	108	42
	176	(90)	(118)
Net earnings (loss) attributable to TransAlta shareholders	**82**	(198)	(160)
Preferred share dividends (Note 27)	**30**	50	30
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Weighted average number of common shares outstanding in the year *(millions)*	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 26)	**0.18**	(0.86)	(0.66)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Net earnings (loss)	**176**	(90)	(118)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**(26)**	15	(6)
Losses on derivatives designated as cash flow hedges, net of tax	**—**	—	(1)
Total items that will not be reclassified subsequently to net earnings	**(26)**	15	(7)
Gains (losses) on translating net assets of foreign operations, net of tax	**(59)**	84	(80)
Reclassification of translation gains on net assets of divested foreign operations[2]	**—**	—	(9)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[3]	**21**	(41)	50
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[4]	**—**	—	14
Gains (losses) on derivatives designated as cash flow hedges, net of tax[5]	**61**	(8)	214
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[6]	**(42)**	(46)	(107)
Total items that will be reclassified subsequently to net earnings	**(19)**	(11)	82
Other comprehensive income (loss)	**(45)**	4	75
Total comprehensive income (loss)	**131**	(86)	(43)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**54**	(210)	(74)
Non-controlling interests (Note 12)	**77**	124	31
	131	(86)	(43)

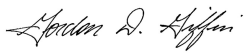
(1) Net of income tax recovery of $ 7 million for the year ended Dec. 31, 2019 (2018 - $ 5 million expense, 2017 - $(4) million recovery).
(2) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $ 11 million expense).
(3) Net of income tax expense of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $ 2 million expense).
(4) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $ 2 million recovery).
(5) Net of income tax expense of $ 16 million for the year ended Dec. 31, 2019 (2018 - $ 1 million recovery, 2017 - $ 77 million recovery).
(6) Net of reclassification of income tax expense of $ 10 million for the year ended Dec. 31, 2019 (2018 - $ 11 million expense, 2017 - $ 31 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018
Cash and cash equivalents	**411**	89
Restricted cash (Note 23)	**32**	66
Trade and other receivables (Note 13)	**462**	756
Prepaid expenses	**19**	13
Risk management assets (Note 14 and 15)	**166**	146
Inventory (Note 16)	**251**	242
	1,341	1,312
Long-term portion of finance lease receivables (Note 8)	**176**	191
Risk management assets (Note 14 and 15)	**640**	662
Property, plant and equipment (Note 17)		
Cost	**13,395**	13,202
Accumulated depreciation	**(7,188)**	(7,038)
	6,207	6,164
Right of use assets (Note 18)	**146**	—
Intangible assets (Note 19)	**318**	373
Goodwill (Note 20)	**464**	464
Deferred income tax assets (Note 11)	**18**	28
Other assets (Note 21)	**198**	234
Total assets	**9,508**	9,428
Accounts payable and accrued liabilities	**413**	496
Current portion of decommissioning and other provisions (Note 22)	**58**	70
Risk management liabilities (Note 14 and 15)	**81**	90
Current portion of contract liabilities (Note 5)	**1**	8
Income taxes payable	**14**	10
Dividends payable (Note 26 and 27)	**37**	58
Current portion of long-term debt and lease obligations (Note 23)	**513**	148
	1,117	880
Credit facilities, long-term debt and lease obligations (Note 23)	**2,699**	3,119
Exchangeable securities (Note 14 and 24)	**326**	—
Decommissioning and other provisions (Note 22)	**488**	386
Deferred income tax liabilities (Note 11)	**472**	501
Risk management liabilities (Note 14 and 15)	**29**	41
Contract liabilities (Note 5)	**14**	80
Defined benefit obligation and other long-term liabilities (Note 25)	**301**	287
Equity		
Common shares (Note 26)	**2,978**	3,059
Preferred shares (Note 27)	**942**	942
Contributed surplus	**42**	11
Deficit	**(1,455)**	(1,496)
Accumulated other comprehensive income (Note 28)	**454**	481
Equity attributable to shareholders	**2,961**	2,997
Non-controlling interests (Note 12)	**1,101**	1,137
Total equity	**4,062**	4,134
Total liabilities and equity	**9,508**	9,428

Significant and subsequent events (Note 4)
Commitments and contingencies (Note 35)





On behalf of the Board:

Gordon D. Giffin
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income(1)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2017	$3,094	$942	$10	$ (1,209)	$489	$3,326	$1,059	$4,385
Impact of change in accounting policy	—	—	—	(14)	—	(14)	1	(13)
Adjusted balance as at Jan. 1, 2018	3,094	942	10	(1,223)	489	3,312	1,060	4,372
Net earnings (loss)	—	—	—	(198)	—	(198)	108	(90)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	43	43	—	43
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(54)	(54)	—	(54)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	15	15	—	15
Intercompany FVOCI investments	—	—	—	—	(16)	(16)	16	—
Total comprehensive income (loss)				(198)	(12)	(210)	124	(86)
Common share dividends	—	—	—	(57)	—	(57)	—	(57)
Preferred share dividends	—	—	—	(50)	—	(50)	—	(50)
Shares purchased under NCIB	(35)	—	—	12	—	(23)	—	(23)
Changes in non-controlling interests in TransAlta Renewables (Note 4(N) and 12)	—	—	—	20	4	24	133	157
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(180)	(180)
Balance, Dec. 31, 2018	3,059	942	11	(1,496)	481	2,997	1,137	4,134
Impact of change in accounting policy (Note 3)	**—**	**—**	**—**	**3**	**—**	**3**	**—**	**3**
Adjusted balance as at Jan. 1, 2019	**3,059**	**942**	**11**	**(1,493)**	**481**	**3,000**	**1,137**	**4,137**
Net earnings	**—**	**—**	**—**	**82**	**—**	**82**	**94**	**176**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(38)**	**(38)**	**—**	**(38)**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**19**	**19**	**—**	**19**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(26)**	**(26)**	**—**	**(26)**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**17**	**17**	**(17)**	**—**
Total comprehensive income (loss)				**82**	**(28)**	**54**	**77**	**131**
Common share dividends	**—**	**—**	**—**	**(34)**	**—**	**(34)**	**—**	**(34)**
Preferred share dividends	**—**	**—**	**—**	**(30)**	**—**	**(30)**	**—**	**(30)**
Shares purchased under NCIB	**(83)**	**—**	**—**	**15**	**—**	**(68)**	**—**	**(68)**
Changes in non-controlling interests in TransAlta Renewables	**—**	**—**	**—**	**5**	**1**	**6**	**22**	**28**
Effect of share-based payment plans (Note 29)	**2**	**—**	**31**	**—**	**—**	**33**	**—**	**33**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(135)**	**(135)**
Balance, Dec.31, 2019	**2,978**	**942**	**42**	**(1,455)**	**454**	**2,961**	**1,101**	**4,062**

(1) Refer to Note 28 for details on components of, and changes in, accumulated other comprehensive income (loss).
See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Operating activities			
Net earnings (loss)	**176**	(90)	(118)
Depreciation and amortization (Note 36)	**709**	710	708
Net gain (loss) on sale of assets (Note 4(D) and 17)	**(45)**	—	(1)
Accretion of provisions (Note 22)	**23**	24	23
Decommissioning and restoration costs settled (Note 22)	**(34)**	(31)	(19)
Deferred income tax recovery (Note 11)	**(18)**	(34)	(15)
Unrealized (gain) loss from risk management activities	**(32)**	30	(48)
Unrealized foreign exchange loss	**13**	28	22
Provisions	**13**	7	(7)
Asset impairment charge (Note 7)	**25**	73	20
Other non-cash items	**(102)**	147	175
Cash flow from operations before changes in working capital	**728**	864	740
Change in non-cash operating working capital balances (Note 32)	**121**	(44)	(114)
Cash flow from operating activities	**849**	820	626
Investing activities			
Additions to property, plant and equipment (Note 17 and 36)	**(417)**	(277)	(338)
Additions to intangibles (Note 19 and 36)	**(14)**	(20)	(51)
Restricted cash (Note 23)	**34**	(35)	(30)
Loan receivable (Note 21)	**(10)**	1	(38)
Acquisitions, net of cash acquired (Note 4)	**(117)**	(30)	—
Investment in the Pioneer Pipeline (Note 4(H))	**(83)**	(15)	**—**
Proceeds on sale of property, plant and equipment	**13**	2	3
Proceeds on sale of Wintering Hills facility and Solomon disposition (Note 4(T) and 4(X))	**—**	2	478
Income tax expense on Solomon disposition (Note 4(T) and 11)	**—**	—	(56)
Realized gains on financial instruments	**3**	2	6
Decrease in finance lease receivable	**24**	59	59
Other	**23**	13	(3)
Change in non-cash investing working capital balances	**32**	(96)	57
Cash flow from (used in) investing activities	**(512)**	(394)	87
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 23)	**(119)**	312	26
Repayment of long-term debt (Note 23)	**(96)**	(1,179)	(814)
Issuance of long-term debt (Note 23)	**166**	345	260
Issuance of exchangeable securities (Note 24)	**350**	—	—
Dividends paid on common shares (Note 26)	**(45)**	(46)	(46)
Dividends paid on preferred shares (Note 27)	**(40)**	(40)	(40)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4(O))	**—**	144	—
Repurchase of common shares under NCIB (Note 26)	**(68)**	(23)	—
Realized gains on financial instruments	**—**	48	106
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(106)**	(165)	(172)
Decrease in lease obligations (Note 23)	**(21)**	(18)	(17)
Financing fees and other	**(35)**	(31)	(6)
Change in non-cash financing working capital balances	**—**	2	—
Cash flow used in financing activities	**(14)**	(651)	(703)
Cash flow from (used in) operating, investing, and financing activities	**323**	(225)	10
Effect of translation on foreign currency cash	**(1)**	—	(1)
Increase (decrease) in cash and cash equivalents	**322**	(225)	9
Cash and cash equivalents, beginning of year	**89**	314	305
Cash and cash equivalents, end of year	**411**	89	314
Cash income taxes paid	**35**	87	14
Cash interest paid	**185**	188	230

See accompanying notes.

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

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

II. Energy Marketing Segment

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

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

III. Corporate

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

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on Mar. 3, 2020.

C. Basis of Consolidation

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

2. Significant Accounting Policies

A. Revenue Recognition

I. Revenue from Contracts with Customers - 2019 and 2018 Policy

The Corporation adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018.

The Corporation elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and elected to apply IFRS 15 only to contracts that are active at the date of initial adoption. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to section III below for the accounting policy for years prior to 2018.

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

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

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

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

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

Good or Service	***Description***
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (i.e., monthly) in an amount representative of availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract Power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal Energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Environmental Attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental 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 environmental attributes. Obligations to deliver environmental 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.

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

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

II. Revenue from Other Sources

Lease Revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Corporation retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

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

III. Revenue Recognition Policy Prior to 2018

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

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

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

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

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

Classification and Measurement

IFRS 9 introduced 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 ("FVOCI").

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

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

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the US where project investors acquire an equity investment in the project entity and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Corporation then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity financings will be classified as a non-controlling interest. In applying the effective interest method to tax equity financings, the Corporation has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. Financial Instruments and Hedges Accounting Policy Prior to 2018
Financial Instruments
Financial assets and financial liabilities, including derivatives and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. Emission Credits and Allowances
Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Corporation records the credits using the specific identification method. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

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

G. Property, Plant and Equipment

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

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

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

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized.

The estimate of the useful life of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

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

Coal generation	2-10 years
Pipeline	50 years
Gas generation	2-30 years
Hydro generation	2-60 years
Wind generation	2-30 years
Mining property and equipment	2-10 years
Capital spares and other	2-60 years

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

H. Intangible Assets

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

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

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

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

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

Software	2-7 years
Power sale contracts	1-20 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's operations, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment charge is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

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

P. Assets Held for Sale

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

Q. Leases

I. 2019 Lease Policy

The Corporation adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. As a result, in 2019, the Corporation changed its accounting policy for leases, which is outlined below. Refer to (II) below for information on the prior accounting policy.

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

Lessee

The Corporation enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Corporation is the lessee, and which are not exempt as short-term or low-value leases, the Corporation:

- Recognizes right of use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right of use assets and interest expense on lease obligations in the Consolidated Statements of Earnings (loss); and
- Recognizes the principal repayments on lease obligations as financing activities and interest payments on lease obligations as operating activities in the Consolidated Statements of Cash Flow.

For short-term and low-value leases, the Corporation recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right of use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right of use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation's estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the carrying amount of the right of use asset, or is recorded in profit or loss if the carrying amount of the right of use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Corporation is reasonably certain to exercise that option and periods covered by an option to terminate if the Corporation is reasonably certain not to exercise that option.

Right of use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right of use asset reflects that the Corporation expects to exercise the purchase option, the related right of use asset is depreciated over the useful life of the underlying asset.

The Corporation has elected to apply the practical expedient that permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement.

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

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

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

When the Corporation has subleased all or a portion of an asset it is leasing and for which it remains the primary obligor under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right of use asset arising from the head lease.

II. Lease Policy Prior to 2019
A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

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

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

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

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

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

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

S. Non-Controlling Interests

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

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

T. Joint Arrangements

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

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

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

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

U. Government Incentives

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

V. Earnings per Share

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

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

W. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

In 2019, the Corporation early-adopted amendments to IFRS 3 *Business Combinations* in advance of the mandatory effective date of Jan. 1, 2020. The amendments, among other things, introduced an optional fair value concentration test that can be applied on a transaction-by-transaction basis, to permit a simplified assessment of whether an acquired set of activities and assets are not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Corporation may elect to treat the acquisition as an asset acquisition and not as a business combination.

X. Stripping Costs

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

Y. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

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

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2017 to 2019 is found in Notes 7, 17 and 20.

II. Leases

In determining whether the Corporation's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Corporation is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes

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

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

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

When the Corporation enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Corporation must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Corporation's expected purchase, sale or usage requirements (i.e. normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Corporation considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate, and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion.

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

VI. Provisions for Decommissioning and Restoration Activities
TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 22. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2019 in respect of decommissioning and restoration provisions can be found in Note 3(A)(IV) and Notes 7 and 22.

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

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 30 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, the Corporation recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 22 with respect to other provisions.

X. Revenue from Contracts with Customers
Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods 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.

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

The satisfaction of performance obligations requires management to make judgments 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 permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements
Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, which classification affects the accounting for the joint arrangement. In making this classification, the Corporation exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

3. Accounting Changes

A. Current Accounting Changes

I. IFRS 16 *Leases*

The Corporation adopted IFRS 16 with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* ("IAS 17") or International Financial Reporting Interpretations Committee Interpretation 4 *Determining Whether an Arrangement Contains a Lease*

The Corporation elected to adopt IFRS 16 using the modified retrospective approach on transition. The Corporation applied the definition of a lease and related guidance set out in IFRS 16 to all lease contracts in existence at Dec. 31, 2018. All relevant contractual arrangements outstanding at that date were reviewed to assess if the contract meets the new definition of a lease.Comparative information has not been restated and is reported under IAS 17. Refer to Note 2(Q)(II) for details on the accounting policy in prior years.

The Corporation recognized the cumulative impact of the initial application of the standard of $3 million in deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019, and for low value leases;
- Excluded initial direct costs from the measurement of the right of use asset at the date of initial application;
- Used hindsight to determine the lease term where the contract contained options to extend or terminate the lease;
- Adjusted the right of use assets by the amount relating to onerous contract provisions as defined under IAS 37*Provisions, contingent liabilities and contingent assets* ("IAS 37") immediately before the date of initial application; and
- Measured the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments related to that lease that was recognized in the statement of financial position immediately before the date of initial application.

Impact on the Financial Statements

Lessee

The Corporation recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on Jan. 1, 2019, was 5.71 per cent.

The following table reconciles the Corporation's operating lease commitments at Dec. 31, 2018, as previously disclosed in the Corporation’s 2018 annual consolidated financial statements, to the lease obligations recognized on initial application of IFRS 16 and included in credit facilities, long-term debt and lease obligations on the Consolidated Statements of Financial Position as at Jan. 1, 2019:

Non-cancellable operating lease commitments disclosed at Dec. 31, 2018	80
Less: Exemption for low-value leases	(1)
Add: Extension and termination options reasonably certain to be exercised	4
Undiscounted lease liability	83
Discounted using the incremental borrowing rate at Jan. 1, 2019	(31)
New lease liabilities recognized as at Jan. 1, 2019	52
Add: 2018 finance lease obligations	63
Less: 2018 finance lease obligations that do not meet the IFRS 16 definition of a lease	(32)
Lease liabilities as at Jan. 1, 2019	**83**

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of $85 million, including $38 million that was previously included in PP&E, intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16 resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in deficit.

Lessor
Several of the Corporation's long-term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these contracts are now accounted for applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

For further details on the lease policy under IFRS 16, refer to Note 2(Q)(I) and to Note 18 for a summary of the Corporation's leases.

II. IFRS 3 Business Combinations

Effective Oct. 1, 2019, the Corporation early-adopted amendments to IFRS 3*Business Combinations* ("IFRS 3 amendments"), in advance of its mandatory effective date of Jan. 1, 2020. The Corporation adopted the IFRS 3 amendments prospectively and therefore the comparative information presented for 2018 has not been restated. The IFRS 3 amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. Specifically, these amendments:

- Clarify the minimum requirements for a business, whereby at minimum, an input and a substantive process that together significantly contribute to the ability to create output must be present;
- Remove the assessment of whether market participants are capable of replacing any missing elements so that the assessment is based on what has been acquired in its current state and condition, rather than on whether market participants are capable of replacing any missing elements, for example, by integrating the acquired activities and assets;
- Add guidance to help entities assess whether an acquired process is substantive, which requires more persuasive evidence when there are no outputs, because the existence of outputs provides some evidence that the acquired set of activities and assets is a business;
- Narrow the definition of outputs to focus on goods or services provided to customers, investment income or other income from ordinary activities; and
- Introduce an optional fair value concentration test that can be applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets are not a business. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The Corporation elected to apply the optional fair value concentration test to its acquisition of the remaining 50 per cent interest in Keephills 3 (refer to Note 4(D) for further details). There are no other impacts to the asset acquisitions that were completed during the year ended Dec. 31, 2019.

III. IFRIC 23 - Uncertainty over Income Tax Treatments

The Corporation adopted IFRIC *23 Uncertainty over Income Tax Treatments* on its effective date of Jan. 1, 2019 and applied it retrospectively. No cumulative effect of initially applying the guidance arose. The Interpretation clarifies the application of recognition and measurement requirements in IAS 12 *Income Taxes* when there is uncertainty over income tax treatments and provides guidance on: considering uncertain tax treatments separately or together; examination by tax authorities; the appropriate method to reflect uncertainty; and accounting for changes in facts and circumstances.

IV. Change in Estimates

Canadian Coal
During the third quarter of 2019, the Corporation adjusted the useful lives of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see Note 4(A) for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019 increased by approximately $16 million.

In 2018, as a result of the Off-Coal Agreement (“OCA”) with the Government of Alberta described in Note 9(A), the Corporation adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. In addition, on Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation’s Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2018, increased by approximately $38 million (2017 - $58 million). The useful lives may be revised or extended in compliance with the Corporation’s accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation’s decision to retire Sundance Unit 1 effective Jan. 1, 2018 (refer to Note 7 for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2019. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 was shut down two years early, the Canadian Minister of Environment & Climate Change agreed to extend the useful life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the useful life of Sundance Unit 2 to 2021. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017 decreased in total by approximately $4 million. However, in the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment charge for the remaining net book value of the asset (refer to Note 7 for further details).

Wind and Solar
During the third quarter of 2019, the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. Accordingly, depreciation expense for the year ended Dec. 31, 2019 increased by approximately $11 million.

Sheerness
During the second quarter of 2019, the Corporation adjusted the useful life of its Sheerness coal-fired plant assets to align with the dual-fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the year ended Dec. 31, 2019 decreased by approximately $8 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia
During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

TransAlta estimates that the undiscounted amount of cash flow required to settle this additional obligation is approximately $222 million, which will be incurred between 2021 and 2035. The provision may be revised in compliance with the Corporation's accounting policies, dependent upon future operating decisions and as more information becomes available.

B. Comparative Figures

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

4. Significant and Subsequent Events

A. Clean Energy Investment Plan

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017.

TransAlta's plan includes converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. As discussed further below in this section, the Corporation is also advancing permitting to convert one, or possibly two, of its units to highly efficient combined-cycle natural gas units. The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of the Alberta thermal assets; and
- Significantly reducing air emissions and costs.

On Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F class gas turbines and related equipment for $84 million. These turbines will be redeployed to TransAlta's Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. TransAlta expects to issue Limited Notice to Proceed ("LNTP") in 2020 and Full Notice to Proceed ("FNTP") in 2021 for the Sundance Unit 5 repowering, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined-cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million. In conjunction with the Sundance Unit 5 permitting, TransAlta is also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined-cycle unit, depending on market fundamentals. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of greenhouse gas ("GHG") costs, starting in late 2023 with Shell Energy North America (Canada).

The Corporation's Clean Energy Investment Plan also consists of three wind projects in the United States, one wind project in Alberta and a cogeneration facility. The Big Level and Antrim wind projects began commercial operations on Dec. 19, 2019 and Dec, 24, 2019, respectively. The Skookumchuck and Windrise wind projects are currently under construction. These projects are underpinned by long-term PPAs with highly creditworthy counterparties. In addition, TransAlta is currently constructing a cogeneration facility which will be jointly owned, operated and maintained with SemCAMS.

B. Acquisition of Wind Development Projects

During 2019, TransAlta acquired a portfolio of wind development projects in the US. If the Corporation decides to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025.

C. Agreement to Construct and Own a Cogeneration Plant in Alberta

On Oct. 1, 2019, TransAlta and SemCAMS Midstream ULC ("SemCAMS") announced that they had entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights.

D. TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the 466 MW Genesee 3 facility for Capital Power's 50 per cent ownership interest in the 463 MW Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The transaction price for each non-operating interest largely offset each other, resulting in a net payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

As discussed in Note 3(A)(II), the Corporation early-adopted 2020 amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test. The Corporation elected to apply the optional fair value concentration test to its acquisition of the non-operating interest in Keephills 3, through which it was determined that greater than 90 per cent of the fair value was concentrated in the PP&E acquired. As a result, the acquisition was determined to not be a business and IFRS 3 requirements were not applied and the existing carrying amount of the owned 50 per cent of Keephills 3 was not required to be assessed at fair value. Consequently, the acquisition has been accounted for as an asset acquisition, with the following carrying amounts assigned based on relative fair values:

Working capital	11
Property, plant and equipment	308
Other assets	3
Other liabilities	(2)
Decommissioning and other provisions	(19)
Total acquisition cost	**301**

The sale of Genesee 3 resulted in a gain of $77 million, which was recognized in gains on sale of assets and other on the statement of earnings during the fourth quarter of 2019.

On the closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. The Sunhills mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. On Oct. 1, 2019, upon termination of this agreement, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings in the fourth quarter of 2019.

E. Termination of the Alberta Sundance Power Purchase Arrangements

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective Mar. 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective Mar. 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on Mar. 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation, which the Corporation pursued from the Balancing Pool through an arbitration initiated under the PPAs. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full amount it was seeking to recover of $56 million, plus GST and interest.

F. Strategic Investment by Brookfield

On Mar. 25, 2019, the Corporation announced that it had entered into an agreement (the "Investment Agreement") whereby Brookfield Renewable Partners or its affiliates (collectively “Brookfield”) agreed to invest $750 million (the "Investment") in the Corporation. Under the terms of the Investment Agreement, Brookfield agreed to invest $750 million in the Corporation through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta’s Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets’ future adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA").

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures. See Note 24 for further details.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation, and maximizing the value, of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the operations, maintenance and administration expense on the statements of earnings (loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment (which occurred on May 1, 2019).

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sep. 14, 2020. Refer to Note 35 for further details.

G. Skookumchuck Wind Project

On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind project, a 136.8 MW wind project currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy. TransAlta has the option to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be $150 million to $160 million, a portion of which is expected to be funded with tax equity financing .

H. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater Midstream and Infrastructure Ltd ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. During the fourth quarter of 2019, TransAlta recognized a right-of-use asset and lease liability for the portion of the Pioneer Pipeline that is not directly owned.

During the year ended Dec. 31, 2019, TransAlta invested $83 million in the Pioneer Pipeline and has invested $100 million life-to-date. The Pioneer Pipeline is held in a separate entity that is a joint operation with Tidewater. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation. The Pioneer Pipeline is classified as a joint operation, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations. If these facts and circumstances change, the classification of the joint arrangement may change.

I. Mothballing of Sundance Units

On Mar. 8, 2019, the Corporation announced that the Alberta Electric System Operator ("AESO") granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020. The extensions were requested by TransAlta based on its assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

J. US Wind Projects

On Feb. 20, 2018, TransAlta Renewables Inc. ("TransAlta Renewables") announced it entered into an arrangement to acquire interests in two construction-ready wind projects in the Northeastern United States (collectively, the "US Wind Projects"). The Big Level wind project ("Big Level") consists of a 90 MW wind project located in Pennsylvania that has a 15-year PPA with Microsoft Corp., and the Antrim wind project ("Antrim") consists of a 29 MW wind project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. The Counterparties in the PPAs all have a Standard & Poor's credit ratings of A+ or better.

A subsidiary of TransAlta acquired Big Level on Mar. 1, 2018 and Antrim on Mar. 28, 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in Big Level from a subsidiary of TransAlta Power Ltd. ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns Big Level directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of Big Level. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, the Corporation recognized $50 million for assets under construction in PP&E and $15 million in intangibles. The TransAlta subsidiary also paid the final holdback for the Big Level development project of $7 million (US$5 million) on the closing of Antrim.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs. TransAlta Renewables funded these costs either by acquiring additional tracking preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes were used exclusively in connection with the acquisition and construction of the US Wind Projects.

During 2019, TransAlta Renewables funded the acquisition of Antrim and the construction costs of the US Wind Projects by subscribing for $142 million (US$105 million) of interest-bearing promissory notes and $78 million (US$59 million) of tracking preferred shares.

Big Level and Antrim each began commercial operations in December 2019. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US$85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the Consolidated Statements of Financial Position.

From the tax equity proceeds, a subsidiary of TransAlta repaid $52 million (US$40 million) of the interest-bearing promissory notes from TransAlta Renewables. The remaining amount of the tax equity proceeds is held as reserves within the project entity and will be released upon certain conditions being met. Once these conditions are met, the reserves will be released and the subsidiary of TransAlta will repay the remaining outstanding interest-bearing promissory notes from TransAlta Renewables.

K. Normal Course Issuer Bid

2019

On May 27, 2019, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may purchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million. See Note 26 for further details.

2018

On March 9, 2018, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to such NCIB, the Corporation was permitted to 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.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled a total of 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million.

L. Windrise

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the three successful projects in the third round of the Renewable Electricity Program. The Windrise wind project, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately $270 million to $285 million and is targeted to reach commercial operation during the first half of 2021.

M. Kent Hills 3 Wind Project

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

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

N. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

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

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge, of which $11 million was recorded against PP&E and $1 million against intangibles. See Note 7 for further details.

O. TransAlta Renewables Closes $150 Million Offering of Common Shares

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

The net proceeds of the Offering were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility was used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(J) above.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 12 for further details of TransAlta's ownership of TransAlta Renewables.

P. $345 Million Financing Related to the Off-Coal Agreement

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

The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

Q. Early Redemption of $400 Million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest. See Note 23 for further details.

R. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its then outstanding 6.650 per cent US$500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense. See Note 23 for further details.

S. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited

On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidiary of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the facility has not reached commercial operation within a specified time period. FMG is asserting that the South Hedland facility did not achieve commercial operation in accordance with the terms of the South Hedland PPA within the specified time period.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation is taking all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized. The South Hedland facility has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA. This matter is scheduled to proceed to trial beginning June 15, 2020. See also Note 35.

T. Reacquisition of Solomon Facility

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon facility from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon facility on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action in the Supreme Court of Western Australia to recover all, or a significant portion of, this amount from FMG. A trial date for this matter has not yet been scheduled. See also Note 35.

U. TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, Kent Hills Wind LP ("KHWLP"), closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds was used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project. The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers, Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP.

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million, which included the principal of $191 million, an early redemption premium of $6 million and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

V. Force Majeure Relief – Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool sought to set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. The Court of Queen's Bench dismissed this application. ENMAX and the Balancing Pool are now attempting to appeal that decision in the Court of Appeal, which requires leave (permission) of the Court. The leave application was heard on Nov. 13, 2019. On Feb. 13, 2019, the Alberta Court of Appeal granted the Balancing Pool and ENMAX permission to appeal. The next step is for TransAlta to continue to defend the arbitration award in the appeal application, which will likely be heard in 2020.

W. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was effective on Jan. 1, 2017, and, in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate, effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. In December 2018, TransAlta exercised its option to terminate its land lease agreement, where the Mississauga facility is located, with Boeing Canada Inc. effective Dec. 31, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

The NUG Contract provided the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations. Further details on the NUG Contract and its impact on these financial statements can be found in Note 9(B).

X. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for net proceeds to the Corporation of $61 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and environmental attributes, leasing of power facilities, and from energy marketing and trading activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	**395**	**10**	**205**	**87**	**244**	**142**	**—**	**—**	**1,083**
Revenue from leases[1]	**65**	**—**	**—**	**65**	**—**	**—**	**—**	**—**	**130**
Revenue from derivatives	**(17)**	**160**	**2**	**—**	**18**	**—**	**129**	**4**	**296**
Government incentives	**—**	**—**	**—**	**—**	**8**	**—**	**—**	**—**	**8**
Revenue from other[2]	**373**	**401**	**2**	**8**	**42**	**14**	**—**	**(10)**	**830**
Total revenue	**816**	**571**	**209**	**160**	**312**	**156**	**129**	**(6)**	**2,347**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	**41**	**10**	**—**	**—**	**27**	**—**	**—**	**—**	**78**
Over time	**354**	**—**	**205**	**87**	**217**	**142**	**—**	**—**	**1,005**
Total revenue from contracts with customers	**395**	**10**	**205**	**87**	**244**	**142**	**—**	**—**	**1,083**

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(2) Includes merchant revenue and other miscellaneous.

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	517	9	224	91	206	132	—	—	1,179
Revenue from leases[1]	68	—	—	68	27	7	—	—	170
Revenue from derivatives	(1)	115	4	—	(20)	—	67	—	165
Government incentives	—	—	—	—	16	—	—	—	16
Revenue from other[2]	328	318	4	6	53	17	—	(7)	719
Total revenue	912	442	232	165	282	156	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	38	9	—	—	18	—	—	—	65
Over time	479	—	224	91	188	132	—	—	1,114
Total revenue from contracts with customers	517	9	224	91	206	132	—	—	1,179

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases (2017 - $ 247 million).
(2) Includes merchant revenue and other miscellaneous.

B. Contract Liabilities

The Corporation has recognized the following revenue-related contract liabilities:

Contract liabilities	**2019**	2018
Balance, beginning of the year	**88**	62
IFRS 16 and 15 transition adjustments[1]	**15**	17
Amounts transferred to revenue included in opening balance	**(10)**	(10)
Consideration received	**5**	13
Increases due to interest accrued and expensed during the period	**5**	6
Contract termination associated with the purchase of Keephills 3 (Note 4(D))	**(88)**	—
Balance, end of year	**15**	88
Current portion	**1**	8
Long-term portion	**14**	80

(1) In 2019, on transition to IFRS 16 some contracts that were previously considered leases under IAS 17 did not meet the definition of a lease under IFRS 16 and therefore were assessed under IFRS 15 and balances were transferred from deferred revenue to contract liabilities. In 2018, this adjustment related to the significant financing component added on adoption of IFRS 15.

Contract liabilities in 2018 were primarily comprised of consideration received from the Corporation's Keephills 3 joint operation partner, Capital Power, for which the Corporation had a future obligation to transfer goods and services to Capital Power under the contract. On closing of the Keephills 3 and Genesee 3 swap, wherein the Corporation acquired Capital Power's 50 per cent ownership interest in Keephills 3 and sold its 50 per cent ownership interest in Genesee 3, the agreement with Capital Power was terminated and the Corporation no longer had any further performance obligations and the related contract liability balance was recognized in net earnings.

The remaining contract liabilities outstanding at Dec. 31, 2019, primarily relate to prepayments relating to the Corporation's New Richmond and Bone Creek facilities where the Corporation still has to fulfil its performance obligations.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

Additionally, in many of the Corporation's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Corporation's influence. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved. Further, adjustments to revenue to recognize a significant financing component in a contract are not included in the amounts disclosed for remaining performance obligations.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Corporation from its contractual portfolio.

Canadian Coal
At Dec. 31, 2019, the Corporation has PPAs with the Balancing Pool for capacity and electricity from two of its coal plants, as dispatched, with contract end dates of Dec. 31, 2020. All generation produced is delivered for the benefit of the customer. Certain sources of revenue under one PPA contract are accounted for as a lease and are excluded from these disclosures. Pricing is comprised of multiple components, of both fixed and variable nature, consisting of a capacity payment based on a return of capital, availability payments (from or to the customer) based on the 30-day rolling average pool price and actual availability of the plant as compared to targeted availability specified in the PPAs, recovery of regulatory pass-through costs, and payments for delivery of energy based on the variable cost of producing the energy. Energy-related payments are variable depending on output from the plant, which is dependent upon market demand and the operational ability of the plant. Revenues are generally recognized over time, on a monthly basis. Future revenues that are based upon variable consideration are considered to be fully constrained and are excluded from these disclosures.

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal plants. The contracts range in duration from one to three years. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

The Corporation has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer, under which the Corporation will receive a fixed capacity payment and variable energy payments based on production.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $452 million, of which the Corporation expects to recognize approximately $116 million over the next fiscal year and on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

US Coal
The Corporation's long-term contract for the sale of electricity produced at its US Coal plant is considered a derivative and is designated as an all-in-one hedge. Accordingly, while revenues for electricity delivered to the customer are recognized pursuant to the contractual terms, the revenues are not accounted for under IFRS 15 and the contract has been excluded from any required IFRS 15 disclosures.

The Corporation also has a contract for the sale of byproducts of coal combustion from its US Coal plant. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

Canadian Gas
At Dec. 31, 2019, the Corporation has contracts with customers to deliver energy services from one of its gas plants in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. A summary of the key terms of these contracts is set out below.

The energy supply agreements require specified amounts of steam to be delivered to each customer, and have pricing terms that include fixed and variable charges for electricity, capacity and steam, as well as a true-up based on contractual minimum volumes of steam. The steam reconciliation is based on an estimate of the customer's steam volume taken and the contractual minimum volume, and various factors including the annual average market price of electricity and the average locally posted and index prices of natural gas, as well as transportation. For steam volumes not taken by the customer, a revenue-sharing mechanism provides for sharing of revenues earned by the Corporation using that steam to generate and sell electricity. Capacity and electricity pricing vary from contract to contract and are subject to annual indexation at varying rates. Electricity and steam delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

At the same gas plant, the Corporation has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Corporation's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2019, the Corporation had contracts with customers to deliver steam, hot water and chilled water from one of its other gas plants in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $18 million in total, of which the Corporation expects to recognize between approximately $4 million to $6 million annually for the duration of the contracts.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to some of the Corporation's other gas facilities' contracts in Ontario; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas

At Dec. 31, 2019, the Corporation has PPAs with customers to deliver electricity from its gas plants located in Australia. One contract is considered to be a lease and is excluded from these disclosures. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2021 to 2042.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $2,095 million, of which the Corporation expects to recognize approximately $223 million in total over the next three fiscal years and on average, between approximately $80 million to $110 million annually thereafter for the duration of the contracts.

Wind and Solar

At Dec. 31, 2019, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind farms located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Corporation expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchaser over the remaining terms of the contracts, from 2020 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $3 million, of which the Corporation expects to recognize between approximately $1 million to $2 million annually through to contract expiry.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to wind energy contracts in Ontario, New Brunswick, Quebec and Wyoming, and for all solar contracts; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Hydro
At Dec. 31, 2019, the Corporation has a PPA with the Balancing Pool to provide the capacity of 12 hydro plants throughout the province of Alberta. The capacity payment is fixed on an annual basis. As part of the PPA, the Corporation also has a financial obligation to the Balancing Pool determined on the basis of notional quantities of electricity delivered and the pool price for the period. The Corporation expects to recognize revenue as it makes capacity available to the customer until completion of the contract term at Dec. 31, 2020. The Corporation also has contracts for blackstart services at specific hydro plants, which conclude in 2020, and a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which concludes in 2021.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $72 million, which the Corporation expects to recognize in the next two fiscal years.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to all hydro energy contracts in Ontario, British Columbia and Washington; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2019**		2018		2017	
	Fuel and purchased power	**Operations, maintenance and administration**	Fuel and purchased power	Operations, maintenance and administration	Fuel and purchased power	Operations, maintenance and administration
Fuel[1]	**669**	**—**	656	—	685	—
Purchased power	**246**	**—**	210	—	162	—
Mine depreciation	**119**	**—**	136	—	73	—
Salaries and benefits[1]	**52**	**228**	98	245	96	248
Other operating expenses	**—**	**247**	—	270	—	269
Total	**1,086**	**475**	1,100	515	1,016	517

(1) $90 million in 2017 was reclassified from fuel to salaries and benefits to be consistent with the 2018 and 2019 classifications.

7. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. 2019

Centralia Plant
In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia Plant CGU exceeded the carrying value, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test, an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	**2016**
Mid-Columbia annual average power prices	**US$30 to US$42 per MWh**	US$22 to US$46 per MWh
On-highway diesel fuel on coal shipments	**US$2.35 to US$2.40 per gallon**	US$1.69 to US$2.09 per gallon
Discount rates	**5.2 to 6.4 per cent**	5.4 to 5.7 per cent

During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

Refer to Note 3(A)(IV) and 22 for further details on the Centralia mine decommissioning and restoration provision.

Assets Held for Sale
In the fourth quarter of 2019, the Corporation identified several trucks and associated inventory to be sold within the Canadian Coal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

B. 2018

Sundance Unit 2
In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $8 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta Merchant CGU. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the unit until its retirement on July 31, 2018. Discounting did not have a material impact.
Lakeswind and Kent Breeze
On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 4(N)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately seven per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (refer to Note 17 and 19).

C. 2017

Sundance Unit 1
In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

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

D. Project Development Costs

During 2019, the Corporation wrote off $18 million (2018 - $23 million) in project development costs related to projects that are no longer proceeding.

8. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases associated with the Poplar Creek cogeneration facility and in 2018, the Fort Saskatchewan cogeneration facility are as follows:

As at Dec. 31	**2019**		2018	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**20**	**20**	30	29
Second to fifth years inclusive	**80**	**74**	80	74
More than five years	**120**	**97**	140	112
	220	**191**	250	215
Less: unearned finance lease income	**29**	**—**	35	—
Total finance lease receivables	**191**	**191**	215	215
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease receivables (Note 13)	**15**		24	
Long-term portion of finance lease receivables	**176**		191	
	191		215	

9. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	**2019**	2018	2017
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Mississauga cogeneration facility NUG Contract	**(1)**	—	(9)
Insurance recoveries	**(10)**	(7)	—
Other expenses	**2**	—	—
Net other operating income	**(49)**	(47)	(49)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The swap of ownership interests in Keephills 3 and Genesee 3 will not impact the payments received. Refer to Note 4(D) for further details.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030. In July 2018, the Corporation obtained financing against the OCA payments. Refer to Note 4(P) and 23 for further details.

B. Mississauga Cogeneration Facility Contract

On Dec. 22, 2016, the Corporation announced it had signed the NUG Contract with the IESO for its Mississauga cogeneration facility. The contract was effective on Jan. 1, 2017. The Corporation agreed to terminate the prior contract with the IESO early, which would have otherwise terminated in December 2018.

During the fourth quarter of 2017, the Corporation renegotiated the facility's land lease agreement at a lower cost than previously estimated in 2016, and accordingly, recognized a gain of $9 million.

In December 2018, TransAlta exercised its option to terminate its land lease agreement for the site with Boeing Canada Inc. effective Jan. 1, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

C. Insurance Recoveries

During 2019, the Corporation received $10 million in insurance recoveries, which related to insurance proceeds for tower fires at Wyoming Wind and Summerview.

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related to insurance proceeds for the tower fire at Wyoming Wind and a $1 million claim related to equipment repairs within Canadian Coal. There wereno insurance recoveries in 2017.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2019**	2018	2017
Interest on debt	**161**	184	218
Interest on exchangeable securities (Note 24)	**20**	—	—
Interest income	**(13)**	(11)	(7)
Capitalized interest (Note 17)	**(6)**	(2)	(9)
Loss on redemption of bonds (Note 23)	**—**	24	6
Interest on finance lease obligations	**4**	3	3
Credit facility fees, bank charges and other interest	**15**	13	18
Tax shield on tax equity financing (Note 23)[1]	**(35)**	—	—
Other[2]	**10**	15	(3)
Accretion of provisions (Note 22)	**23**	24	21
Net interest expense	**179**	250	247

(1) Relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim wind projects that was assigned to the tax equity investor. The tax equity investment is treated as debt under IFRS and the monetization of the tax depreciation is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.
(2) In 2019, other interest expense included approximately $5 million (2018 - $7 million, 2017 - nil) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $ 5 million of costs were expensed due to project-level financing that is no longer practicable.

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	**2019**	2018	2017
Earnings before income taxes	**193**	(96)	(54)
Net earnings attributable to non-controlling interests not subject to tax	**(26)**	(19)	(35)
Adjusted earnings before income taxes	**167**	(115)	(89)
Statutory Canadian federal and provincial income tax rate (%)	**26.5 %**	26.8 %	26.8 %
Expected income tax expense (recovery)	**44**	(31)	(24)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**5**	(3)	(11)
Writedown (reversal of writedown) of deferred income tax assets	**(9)**	27	(15)
Statutory and other rate differences	**(31)**	—	110
Other	**8**	1	4
Income tax expense (recovery)	**17**	(6)	64
Effective tax rate (%)	**10 %**	5 %	72 %

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2019	2018	2017
Current income tax expense[1]	**35**	28	79
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**22**	(61)	(110)
Deferred income tax expense resulting from changes in tax rates or laws [2,3]	**(31)**	—	110
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[4]	**(9)**	27	(15)
Income tax expense (recovery)	**17**	(6)	64

Year ended Dec. 31	2019	2018	2017
Current income tax expense	**35**	28	79
Deferred income tax recovery	**(18)**	(34)	(15)
Income tax expense (recovery)	**17**	(6)	64

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon facility Nov. 1, 2017.
(2) In 2019, the Corporation recognized a deferred income tax recovery of $ 31 million related to a decrease in the Alberta corporate tax rate from 12 per cent to 8 per cent. The tax decrease is phased in as follows: 11 per cent effective July 1, 2019, 10 per cent effective January 1, 2020, 9 per cent effective January 1, 2021, and 8 per cent effective January 1, 2022.
(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act, which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $ 1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $ 111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income.
(4) During the year ended Dec. 31, 2019, the Corporation recorded a reversal of a previous writedown of deferred income tax assets of $ 9 million (2018 - $ 27 million writedown, 2017 - $ 15 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation 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. The Corporation previously wrote these assets off when it was not considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. Recognized ordinary income and other comprehensive income 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.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	**2019**	2018	2017
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**6**	(12)	(108)
Net impact related to net investment hedges	**—**	—	(7)
Net actuarial gains (losses)	**(7)**	5	(4)
Income tax expense reported in equity	**(1)**	(7)	(119)

C. Consolidated Statements of Financial Position

Significant components of the Corporation's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	**2019**	2018
Net operating loss carryforwards	**494**	547
Future decommissioning and restoration costs	**122**	113
Property, plant and equipment	**(828)**	(896)
Risk management assets and liabilities, net	**(141)**	(145)
Employee future benefits and compensation plans	**56**	68
Interest deductible in future periods	**42**	48
Foreign exchange differences on US-denominated debt	**40**	35
Deferred coal revenues	**—**	23
Other deductible temporary differences	**4**	—
Net deferred income tax liability, before writedown of deferred income tax assets	**(211)**	(207)
Writedown of deferred income tax assets	**(243)**	(266)
Net deferred income tax liability, after writedown of deferred income tax assets	**(454)**	(473)

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	**2019**	2018
Deferred income tax assets[1]	**18**	28
Deferred income tax liabilities	**(472)**	(501)
Net deferred income tax liability	**(454)**	(473)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2019, the Corporation had recognized a net liability of $1 million (2018 - nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2019
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.6% - Public shareholders
Kent Hills Wind LP(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind farm located in New Brunswick.

The South Hedland facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables.

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders may elect to automatically reinvest monthly dividends into additional common shares of the Corporation.

As a result of the conversion of the Class B shares, the DRIP and the Offering described in Note 4(O), the Corporation's share of ownership and equity participation in TransAlta Renewables has changed as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9
Jan. 1, 2019 to Mar. 31, 2019	60.8	60.8
Apr. 1, 2019 to June 30, 2019	60.6	60.6
July 1, 2019 to Sept. 30, 2019	60.5	60.5
Oct. 1, 2019 to Dec. 31, 2019	60.4	60.4

Year ended Dec. 31	2019	2018	2017
Revenues	**446**	462	459
Net earnings	**183**	241	13
Total comprehensive income	**138**	281	(24)
Amounts attributable to the non-controlling interests:			
Net earnings	**73**	94	11
Total comprehensive income	**56**	110	—
Distributions paid to non-controlling interests	**69**	79	85

As at Dec. 31	2019	2018
Current assets	**293**	250
Long-term assets	**3,409**	3,497
Current liabilities	**(152)**	(159)
Long-term liabilities	**(1,237)**	(1,192)
Total equity	**(2,313)**	(2,396)
Equity attributable to non-controlling interests	**(941)**	(961)
Non-controlling interests' share (per cent)	**39.6**	39.1

B. TA Cogen

Year ended Dec. 31	2019	2018	2017
Results of operations			
Revenues	**181**	185	175
Net earnings	**43**	29	61
Total comprehensive income	**43**	29	61
Amounts attributable to the non-controlling interest:			
Net earnings	**21**	14	31
Total comprehensive income	**21**	14	31
Distributions paid to Canadian Power Holdings Inc.	**37**	86	87

As at Dec. 31	2019	2018
Current assets	**41**	82
Long-term assets	**328**	354
Current liabilities	**(27)**	(54)
Long-term liabilities	**(19)**	(28)
Total equity	**(323)**	(354)
Equity attributable to Canadian Power Holdings Inc.	**(160)**	(176)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables

As at Dec. 31	2019	2018
Trade accounts receivable	**399**	597
Promissory note receivable[1]	**—**	25
Collateral paid (Note 15)	**42**	105
Current portion of finance lease receivables (Note 8)	**15**	24
Income taxes receivables	**6**	5
Trade and other receivables	**462**	756

(1) The promissory note receivable relates to funding provided for the Antrim wind project in 2018. Refer to Note 4(J) for further details.

14. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2019

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	**—**	**—**	**411**	**411**
Restricted cash	**—**	**—**	**32**	**32**
Trade and other receivables	**—**	**—**	**462**	**462**
Long-term portion of finance lease receivable	**—**	**—**	**176**	**176**
Risk management assets				
Current	**71**	**95**	**—**	**166**
Long-term	**607**	**33**	**—**	**640**
Other assets (Note 21)	**—**	**—**	**47**	**47**
Financial liabilities				
Accounts payable and accrued liabilities	**—**	**—**	**413**	**413**
Dividends payable	**—**	**—**	**37**	**37**
Risk management liabilities				
Current	**1**	**80**	**—**	**81**
Long-term	**1**	**28**	**—**	**29**
Credit facilities, long-term debt and finance lease obligations[2]	**—**	**—**	**3,212**	**3,212**
Exchangeable securities	**—**	**—**	**326**	**326**

(1) Includes cash equivalents of nil.
(2) Includes current portion.

Carrying value as at Dec. 31, 2018

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Total
Financial assets					
Cash and cash equivalents[1]	—	—	89	—	89
Restricted cash	—	—	66	—	66
Trade and other receivables	—	—	731	25	756
Long-term portion of finance lease receivables	—	—	191	—	191
Risk management assets					
Current	60	86	—	—	146
Long-term	629	33	—	—	662
Other assets	—	—	37	15	52
Financial liabilities					
Accounts payable and accrued liabilities	—	—	496	—	496
Dividends payable	—	—	58	—	58
Risk management liabilities					
Current	1	89	—	—	90
Long-term	1	40	—	—	41
Credit facilities, long-term debt and finance lease obligations[2]	—	—	3,267	—	3,267

(1) Includes cash equivalents of nil.
(2) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

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

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be 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 price relationships.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes and shapes.

As at Dec. 31	**2019**		2018	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale – US	**737**	+46 -139	801	+116 -116
Unit contingent power purchases	**(6)**	+1 -1	18	+4 -4
Structured products – Eastern US	**7**	+2 -2	6	+5 -5
Full requirements – Eastern US	**10**	+3 -3	—	—
Long-term wind energy sale – Eastern US	**(28)**	+20 -20	(39)	+21 -21
Others	**—**	+7 -7	9	+3 -3

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 2021, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$20 to US$28 (Dec. 31, 2018 - US$20 to US$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US$3 to US$9 (Dec. 31, 2018 - US$6) price decrease or increase 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, 2018 to Dec. 31, 2019, the base fair value and the sensitivity values have decreased by approximately $11 million and $2 million, respectively.

ii. Unit Contingent Power Purchases
Under the unit contingent PPAs, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro-rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as FVTPL.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2019, are nil (Dec. 31, 2018 – nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2018 – 2.2 per cent to 16.9 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 1.0 per cent to 2.0 per cent (Dec. 31, 2018 – 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 10.5 per cent (Dec. 31, 2018 – 8.6 per cent and 27.3 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. As at Dec. 31, 2019, the Corporation did not have any open positions on heat rate contracts.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2019, are 91 per cent to 112 per cent and 63 per cent to 116 per cent (Dec. 31, 2018 – 75 per cent to 109 per cent and 63 per cent to 104 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 4.0 per cent to 6.0 per cent (Dec. 31, 2018 – 4.2 per cent to 6.9 per cent) and a change in non-standard shape factors of approximately 4.0 per cent to 10.0 per cent (Dec. 31, 2018 – 4.0 per cent to 9.3 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. As there are no open positions on Level III heat rate option contracts, the implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2019, are nil and nil (Dec. 31, 2018 – 25 per cent to 84 per cent and 70 per cent), respectively. The sensitivity analysis was prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately nil and nil, respectively (2018 – 37 per cent to 49 per cent and 30 per cent, respectively).

iv. Full Requirements – Eastern US
The Corporation has a portfolio of full requirement service contracts, whereby the Corporation agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits and Independent System Operator costs.

The key unobservable inputs used in the portfolio valuation include delivered volume and supply cost. Hourly shaping of consumption will result in a realized cost that may be at a premium (or discount) relative to the average settled price. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement. The sensitivity analysis has been prepared using the Corporation's assessment that a reasonably possible change in the expected portfolio delivery volumes and portfolio's realized cost of supply of (+/-) 5 per cent and (+/-) US$1 per MWh, respectively.

v. Long-Term Wind Energy Sale – Eastern US
In relation to the acquisition of Big Level (See Note 4(J)), the Corporation has a long-term contract for differences whereby the Corporation receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. 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 2024 and 2022, respectively. Forward power and REC prices per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$38 to US$60 and US$9 (Dec. 31, 2018 – US$42 to US$68 and US$7 to US$8), respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent (2018 – 10 per cent), a change in energy prices of US$5 (2018 – US$6) and a change in REC prices of US$1 (2018 – US$1) as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2019, are as follows: Level I - $3 million net liability (Dec. 31, 2018 – $3 million net asset), Level II – $9 million net asset (Dec. 31, 2018 – $19 million net liability) and Level III – $686 million net asset (Dec. 31, 2018 – $695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2019, are primarily attributable to the settlement of contracts and unfavourable foreign exchange rates, partially offset by favourable market prices.

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, 2019 and 2018, respectively:

	Year ended Dec. 31, 2019			Year ended Dec. 31, 2018		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**689**	**6**	**695**	719	52	771
Changes attributable to:						
Market price changes on existing contracts	**77**	**8**	**85**	(7)	(9)	(16)
Market price changes on new contracts	**—**	**14**	**14**	—	4	4
Contracts settled	**(57)**	**(19)**	**(76)**	(90)	(42)	(132)
Change in foreign exchange rates	**(31)**	**(1)**	**(32)**	67	5	72
Transfers into (out of) Level III	**—**	**—**	**—**	—	(4)	(4)
Net risk management assets at end of period	**678**	**8**	**686**	689	6	695
Additional Level III information:						
Gains recognized in other comprehensive income	**46**	**—**	**46**	60	—	60
Total gains included in earnings before income taxes	**57**	**21**	**78**	90	—	90
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**2**	**2**	—	(42)	(42)

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 asset fair value of $4 million as at Dec. 31, 2019 (Dec. 31, 2018 – $2 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2019, are primarily attributable to favourable market prices on existing contracts.

IV. Other Financial Assets and Liabilities
The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value[1]				Total carrying value[1]
	Level I	Level II	Level III	Total	
Exchangeable securities - Dec. 31, 2019	**—**	**342**	**—**	**342**	**326**
Long-term debt - Dec. 31, 2019	**—**	**3,157**	**—**	**3,157**	**3,070**
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

The fair values of the Corporation's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 21) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses
The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	2019	2018	2017
Unamortized net gain at beginning of year	**49**	105	148
New inception gains (losses)	**3**	(14)	12
Change in foreign exchange rates	**—**	5	(7)
Amortization recorded in net earnings during the year	**(43)**	(47)	(48)
Unamortized net gain at end of year	**9**	49	105

15. Risk Management Activities
A. Risk Management Strategy
The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: i) financial exposure management and ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges, and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**70**	**15**	**85**
Long-term	**606**	**1**	**607**
Net commodity risk management assets	**676**	**16**	**692**
Other			
Current	**—**	**—**	**—**
Long-term	**—**	**4**	**4**
Net other risk management assets	**—**	**4**	**4**
Total net risk management assets	**676**	**20**	**696**

As at Dec. 31, 2018

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	59	—	59
Long-term	628	(8)	620
Net commodity risk management assets (liabilities)	687	(8)	679
Other			
Current	—	(3)	(3)
Long-term	—	1	1
Net other risk management liabilities	—	(2)	(2)
Total net risk management assets (liabilities)	687	(10)	677

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	**2019**				2018			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**316**	**631**	**(191)**	**(100)**	224	657	(116)	(42)
Gross amounts set-off	**(140)**	**(42)**	**140**	**42**	(53)	(6)	53	6
Net amounts as included in the Consolidated Statements of Financial Position	**176**	**589**	**(51)**	**(58)**	171	651	(63)	(36)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

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

To mitigate the risk of adverse commodity price changes, the Corporation uses three tools:

- A framework of risk controls;
- A pre-defined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Corporation has executed commodity price hedges for its Centralia coal plant and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Corporation's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Corporation's exposure to market risks or the manner in which these risks are managed or measured.

i. Commodity Price Risk Management – Proprietary Trading
The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2019, associated with the Corporation's proprietary trading activities was $1 million (2018 - $2 million, 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 Dec. 31, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $25 million (2018 - $18 million, 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 Dec. 31, 2019, associated with these transactions was $8 million (2018 - $13 million, 2017 - $5 million).

iii. Commodity Price Risk Management – Hedges
The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2019**		2018	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**222**	**—**	2,128	—

During 2019, unrealized pre-tax gains of $1 million (2018 - $4 million, 2017 - $2 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management – Non-Hedges
The Corporation's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2019		2018	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**16,097**	**7,204**	58,885	37,023
Natural gas *(GJ)*	**38,062**	**55,023**	80,413	110,488
Transmission *(MWh)*	**—**	**1,818**	29	11,163
Emissions *(MWh)*	**184**	**138**	—	—
Emissions *(tonnes)*	**2,436**	**2,446**	3,134	2,948

b. Interest Rate Risk Management
Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the Alberta coal PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represents 11 per cent of the Corporation's debt as at Dec. 31, 2019 (2018 – 14 per cent).

Interest rate risk is managed with the use of derivatives. No derivatives related to interest rate risk were outstanding as at Dec. 31, 2019, 2018 or 2017.

c. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Corporation may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

i. Net Investment Hedges
When designating foreign currency debt as a hedge of the Corporation's net investment in foreign subsidiaries, the Corporation has determined that the hedge is effective as the foreign currency of the net investment is the same as the currency of the hedge, and therefore an economic relationship is present.

The Corporation's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$70 million (2018 - US$400 million).

ii. Cash Flow Hedges
The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31		2019			2018			
Notional amount sold	**Notional amount purchased**	**Fair value asset**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
CAD124	**USD95**	**—**	**2020-2021**	—	—	—	—

iii. Non-Hedges
As part of the sale of the Corporation's economic interest in the Australian Assets to TransAlta Renewables, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in the USD and AUD in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program.

The Corporation also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31		**2019**			2018		
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures							
AUD286	**CAD266**	**—**	**2020 - 2023**	AUD218	CAD205	(5)	2019-2022
USD108	**CAD139**	**(4)**	**2020 - 2023**	USD164	CAD214	(7)	2019-2022
Foreign exchange forward contracts – foreign-denominated debt							
CAD191	**USD150**	**6**	**2022**	CAD124	USD100	10	2022

iv. Impacts of currency rate risk
The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cent (2018 and 2017 - four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2019**		2018		2017	
Currency	**Net earnings increase (decrease)[1]**	**OCI gain[1],[2]**	Net earnings increase[1]	OCI gain[1],[2]	Net earnings decrease[1]	OCI gain[1],[2]
USD	**(18)**	**2**	(13)	—	(5)	—
AUD	**(6)**	**—**	(7)	—	(7)	—
Total	**(24)**	**2**	(20)	—	(12)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk
Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2019:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	85	15	**100**	**462**
Long-term finance lease receivable	100	—	**100**	**176**
Risk management assets[1]	99	1	**100**	**806**
Loan receivable[2]	—	100	**100**	**47**
Total				**1,491**

(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. Refer to Note 21 for further details.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on historical rates of default by segment of trade receivables as well as forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2019.

The Corporation's maximum exposure to credit risk at Dec. 31, 2019, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2019, was $5 million (2018 - $13 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 Dec. 31, 2019, TransAlta maintains investment grade ratings from one credit rating agency and below investment grade ratings from three credit rating agencies. Between 2020 and 2022, the Corporation has approximately $1,217 million of debt maturing, comprised of approximately $920 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022. Refer to Note 4(F) and 24 for further details.

Collateral is posted based on negotiated terms with counterparties, which can include 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.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Board; and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Corporation does not use derivatives or hedge accounting to manage liquidity risk.

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

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Accounts payable and accrued liabilities	413	—	—	—	—	—	413
Long-term debt[1]	494	98	625	372	105	1,410	3,104
Exchangeable securities[2]	—	—	—	—	—	350	350
Commodity risk management assets	(89)	(89)	(143)	(139)	(135)	(97)	(692)
Other risk management (assets) liabilities	1	—	(6)	2	—	(1)	(4)
Lease obligations	19	14	9	6	4	90	142
Interest on long-term debt and lease obligations[3]	161	138	128	98	87	671	1,283
Interest on exchangeable securities[2, 3]	25	25	25	24	24	—	123
Dividends payable	37	—	—	—	—	—	37
Total	**1,061**	**186**	**638**	**363**	**85**	**2,423**	**4,756**

(1) Excludes impact of hedge accounting.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Refer to Note 24 for further details.
(3) Not recognized as a financial liability on the Consolidated Statements of Financial Position .

IV. Equity Price Risk

a. Total Return Swaps

The Corporation has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2020	2021	2022	2023	2024	2025 and thereafter
Cash flow hedges						
Foreign Currency Forward Contracts						
Notional amount ($ millions)						
CAD/USD	116	8	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7672	0.7686	—	—	—	—
Commodity Derivative Instruments						
Electricity						
Notional amount (thousands MWh)	3,465	3,424	3,329	3,329	3,338	2,628
Average Price ($ per MWh)	67.82	71.06	73.55	75.39	77.28	79.20

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2019

	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	**19 MMWh**	**678**	**Risk management assets**	**47**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD483**	**Credit facilities, long-term debt and finance lease obligations**	**21**

As at Dec. 31, 2018

	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	23 MMWh	687	Risk management assets	60
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD400	CAD546	Credit facilities, long-term debt and finance lease obligations	(41)

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31, 2019	**2019**		2018	
	Change in fair value used for measuring ineffectiveness	**Cash flow hedge reserve[1]**	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**47**	**527**	60	508

	Change in fair value used for measuring ineffectiveness	**Foreign currency translation reserve[1]**	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]
Net investment hedges				
Net investment in foreign subsidiaries	**21**	**(21)**	(41)	17

(1) Included in AOCI

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness. There is no ineffectiveness recognized in profit or loss.

The impact of hedged items designated in hedging relationships on OCI and net earnings is:

Year ended Dec. 31, 2019

	Effective portion			**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**77**	Revenue	**(59)**	Revenue	**—**
Forward starting interest rate swaps	**—**	Interest expense	**6**	Interest expense	**—**
OCI impact	**77**	**OCI impact**	**(53)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $68 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2018

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(9)	Revenue	(67)	Revenue	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	(9)	OCI impact	(57)	Net earnings impact	—

Year ended Dec. 31, 2017 (as reported under IAS 39)

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	163	Revenue	(172)	Revenue	—
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Cross-currency swaps	(26)	Foreign exchange (gain) loss	24	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	136	OCI impact	(138)	Net earnings impact	—

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminated the contract effective Jan. 1, 2017. Accordingly, in 2017 the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 9(B) for further details.

II. Effect of Non-Hedges
For the year ended Dec. 31, 2019, the Corporation recognized a net unrealized gain of $33 million (2018 - loss of $29 million, 2017 - gain of $45 million) related to commodity derivatives.

For the year ended Dec. 31, 2019, a gain of $24 million (2018 - gain of $3 million, 2017 - gain of $28 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized gains of $6 million (2018 - gains of $4 million, 2017 - losses of $2 million) and net realized gains of $18 million (2018 - losses of $1 million, 2017 - gains of $30 million).

F. Collateral

I. Financial Assets Provided as Collateral
At Dec. 31, 2019, the Corporation provided $42 million (2018 – $105 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral
At Dec. 31, 2019, the Corporation held $3 million (2018 – $17 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments
Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

As at Dec. 31, 2019, the Corporation had posted collateral of $112 million (Dec. 31, 2018 – $120 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 $51 million (Dec. 31, 2018 – $120 million) of collateral to its counterparties.

16. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.
The components of inventory are as follows:

As at Dec. 31	**2019**	2018
Parts and materials	**108**	113
Coal	**130**	108
Deferred stripping costs	**6**	7
Natural gas	**3**	4
Purchased emission credits	**4**	10
Total	**251**	242

The change in inventory is as follows:

Balance, Dec. 31, 2017	219
Net addition	20
Change in foreign exchange rates	3
Balance, Dec. 31, 2018	242
Net addition	**12**
Change in foreign exchange rates	**(3)**
Balance, Dec. 31, 2019	**251**

No inventory is pledged as security for liabilities.

17. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2017	95	5,888	1,982	3,228	1,315	95	370	12,973
Additions[2]	—	—	—	1	—	275	8	284
Additions - finance lease	—	—	—	—	10	—	—	10
Disposals	(3)	—	—	—	(1)	—	(3)	(7)
Impairment charge (Note 7)	—	(38)	—	(11)	—	—	—	(49)
Revisions and additions to decommissioning and restoration costs	—	(12)	(1)	(3)	(16)	—	—	(32)
Retirement of assets	—	(47)	(17)	(6)	(16)	—	(4)	(90)
Change in foreign exchange rates	2	105	(13)	26	7	4	—	131
Transfers	—	41	13	51	39	(174)	12	(18)
As at Dec. 31, 2018	94	5,937	1,964	3,286	1,338	200	383	13,202
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(7)**	**(101)**	**—**	**—**	**(108)**
Additions[4]	**—**	**—**	**—**	**—**	**—**	**407**	**115**	**522**
Acquisitions (Note 4(D) and 4(J))[5]	**—**	**300**	**—**	**—**	**—**	**139**	**—**	**439**
Disposals[6]	**(2)**	**(389)**	**(260)**	**—**	**(34)**	**—**	**(19)**	**(704)**
Impairment (charges) reversals (Note 7)	**—**	**448**	**—**	**(2)**	**(15)**	**—**	**—**	**431**
Revisions and additions to decommissioning and restoration costs	**—**	**(62)**	**11**	**2**	**26**	**—**	**—**	**(23)**
Retirement of assets	**—**	**(158)**	**(26)**	**(7)**	**(10)**	**—**	**—**	**(201)**
Change in foreign exchange rates	**(1)**	**(63)**	**(40)**	**(17)**	**(3)**	**(4)**	**(6)**	**(134)**
Transfers[7]	**—**	**103**	**22**	**319**	**25**	**(514)**	**16**	**(29)**
As at Dec. 31, 2019	**91**	**6,116**	**1,671**	**3,574**	**1,226**	**228**	**489**	**13,395**
Accumulated depreciation								
As at Dec. 31, 2017	—	3,431	1,072	1,037	713	—	142	6,395
Depreciation	—	306	79	123	125	—	16	649
Retirement of assets	—	(56)	(13)	(2)	(12)	—	—	(83)
Disposals	—	—	—	—	(1)	—	(4)	(5)
Change in foreign exchange rates	—	84	(3)	6	5	—	—	92
Transfers	—	—	(7)	(3)	—	—	—	(10)
As at Dec. 31, 2018	—	3,765	1,128	1,161	830	—	154	7,038
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(3)**	**(43)**	**—**	**—**	**(46)**
Depreciation	**—**	**304**	**77**	**136**	**97**	**—**	**16**	**630**
Retirement of assets	**—**	**(158)**	**(23)**	**(3)**	**(6)**	**—**	**—**	**(190)**
Disposals[5]	**—**	**(170)**	**(255)**	**—**	**(14)**	**—**	**—**	**(439)**
Impairment reversal (Note 7)	**—**	**297**	**—**	**—**	**—**	**—**	**—**	**297**
Change in foreign exchange rates	**—**	**(52)**	**(16)**	**(4)**	**(2)**	**—**	**(2)**	**(76)**
Transfers	**—**	**10**	**(11)**	**(3)**	**(22)**	**—**	**—**	**(26)**
As at Dec. 31, 2019	**—**	**3,996**	**900**	**1,284**	**840**	**—**	**168**	**7,188**
Carrying amount								
As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
As at Dec. 31, 2019	**91**	**2,120**	**771**	**2,290**	**386**	**228**	**321**	**6,207**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance, and the Australian gas pipeline.
(2) Includes $7 million related to the acquisition of Big Level.
(3) Includes net $33 million transferred to right of use assets and $ 29 million of finance lease assets that were derecognized on implementation of IFRS 16. Refer to Note 3 for further details.
(4) Includes cash additions of $ 417 million (including $169 million related to the construction of the US Wind Projects), $ 100 million related to the Pioneer Pipeline (including $ 15 million transferred from other assets) and $5 million related to the Keephills 3 and Genesee 3 asset swap. Refer to Note 4 for further details of these transactions.
(5) Includes $308 million related to the acquisition of the Keephills 3 facility with $ 300 million included in coal generation and the remainder in assets under construction.
(6) In 2019, we sold the Genesee 3 facility and sold the major components of the Mississauga facility. In addition, Centralia sold boiler parts included in capital spares and other for a net loss of $ 17 million. The Sunhills mine also sold trucks included in mining property and equipment for a net loss of $18 million. Both were recognized in other gains on the statement of earnings (loss).
(7) Mainly relates to transferring the Pioneer Pipeline and US Wind Projects from assets under construction to coal generation and renewable generation, respectively.

The Corporation capitalized $6 million of interest to PP&E in 2019 (2018 - $2 million) at a weighted average rate of 5.9 per cent (2018 – 4.5 per cent). Finance lease additions in 2018 were for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2019, was nil as these were transferred to right of use assets on implementation of IFRS 16 (2018 - $65 million).

18. Right of Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right of use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Pipeline	Total
New leases recognized Jan. 1, 2019	**29**	**22**	**1**	**—**	—	**52**
Adjustments on recognition[1]	**(1)**	**(4)**	**—**	**—**	—	**(5)**
Transfers from PP&E, intangibles and other assets	**—**	**—**	**3**	**35**	—	**38**
As at Jan. 1, 2019	**28**	**18**	**4**	**35**	—	**85**
Additions	**32**	**2**	**—**	**2**	**45**	**81**
Depreciation	**(1)**	**(4)**	**(2)**	**(11)**	**—**	**(18)**
Change in foreign exchange rates	**(1)**	**—**	**—**	**—**	**—**	**(1)**
Transfers	**—**	**—**	**—**	**(1)**	**—**	**(1)**
As at Dec. 31, 2019	**58**	**16**	**2**	**25**	**45**	**146**

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

In November 2019, the Corporation recognized a right of use asset and corresponding lease liability related to the initial 15-year term of its contract for transporting natural gas on the Pioneer Pipeline. The transportation contract provides the Corporation with the right to extend the contract for up to eight additional renewal periods of 24-months each. The amounts recognized represent the 50 per cent of the pipeline that is not owned by the Corporation.

In December 2019, the Corporation recognized an additional $31 million of right of use assets and $31 million of lease liabilities for land leases at certain wind farms as a result of revised interpretations of the unit of account / identified asset concepts present in IFRS 16.

For the year ended Dec. 31, 2019, TransAlta paid $25 million related to recognized lease liabilities, consisting of $4 million in interest and $21 million in principal repayments.

For the year ended Dec. 31, 2019, the Corporation expensed $2 million related to short-term and $1 million related to low value leases. Short term leases (term of less than 12 months) and leases with total lease payments below the Corporation's capitalization threshold do not require recognition as lease liabilities and right of use assets.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2019, the Corporation expensed $6 million in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 10, 15, 23 and 35.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2017	178	314	223	29	744
Additions[1]	—	—	—	53	53
Retirements and disposals[2]	—	(2)	—	—	(2)
Change in foreign exchange rates	—	3	—	—	3
Transfers	7	24	14	(36)	9
As at Dec. 31, 2018	185	339	237	46	807
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(5)**	**—**	**—**	**(5)**
Additions	**—**	**—**	**—**	**14**	**14**
Acquisition	**—**	**1**	**—**	**15**	**16**
Disposals (Note 4(D))	**(37)**	**(1)**	**—**	**—**	**(38)**
Change in foreign exchange rates	**—**	**(4)**	**(1)**	**(1)**	**(6)**
Transfers	**1**	**48**	**14**	**(63)**	**—**
As at Dec. 31, 2019	**149**	**378**	**250**	**11**	**788**
Accumulated amortization					
As at Dec. 31, 2017	125	188	67	—	380
Amortization	9	32	9	—	50
Retirements and disposals	—	(1)	—	—	(1)
Change in foreign exchange rates	—	2	—	—	2
Transfers	(17)	—	20	—	3
As at Dec. 31, 2018	117	221	96	—	434
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(3)**	**—**	**—**	**(3)**
Amortization	**8**	**31**	**11**	**—**	**50**
Disposals (Note 4(D))	**(9)**	**(1)**	**—**	**—**	**(10)**
Change in foreign exchange rates	**—**	**(1)**	**—**	**—**	**(1)**
Transfers	**1**	**(1)**	**—**	**—**	**—**
As at Dec. 31, 2019	**117**	**246**	**107**	**—**	**470**
Carrying amount					
As at Dec. 31, 2017	53	126	156	29	364
As at Dec. 31, 2018	68	118	141	46	373
As at Dec. 31, 2019	**32**	**132**	**143**	**11**	**318**

(1) Includes $33 million related to the acquisition of Big Level.
(2) Includes the impairment charge of $ 1 million relating to Kent Breeze. See Note 7 for further details.

20. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	2019	2018
Hydro	**258**	259
Wind and Solar	**176**	175
Energy Marketing	**30**	30
Total goodwill	**464**	464

For the purposes of the 2019 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Hydro, Wind and Solar, and Energy Marketing segments by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2019 models ranged between $5 to $183 per MWh during the forecast period (2018 – $6 to $179 per MWh). Discount rates used for the goodwill impairment calculation in 2019 ranged from 3.6 per cent to 7.0 per cent (2018 – 5.3 per cent to 6.6 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

21. Other Assets

The components of other assets are as follows:

As at Dec. 31	2019	2018
South Hedland prepaid transmission access and distribution costs	**67**	72
Deferred licence fees	**9**	11
Project development costs	**19**	47
Deferred service costs	**—**	12
Long-term prepaids and other assets	**56**	55
Loan receivable	**47**	37
Total other assets	**198**	234

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Project development costs include the project costs for Windrise (Note 4(L)) and the US wind development projects (Note 4(B)). Some projects were written off in 2019 and 2018 as they are no longer proceeding (see Note 7(D)).

Deferred service costs related to TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. As part of the Genesee Unit 3 and Keephills Unit 3 swap, these assets were included in the transaction (Note 4(D)).

Long-term prepaids and other assets includes: the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 35(F), the Keephills Unit 3 provincially required transmission deposit which is anticipated to be reimbursed over the next two years to 2021, as long as certain performance criteria are met, and other miscellaneous prepaids and deposits.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $47 million (2018 – $37 million) (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022.

22. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2017	437	33	470
Liabilities incurred	5	17	22
Liabilities settled	(31)	(10)	(41)
Accretion	24	—	24
Acquisition of liabilities (Big Level)	—	8	8
Revisions in estimated cash flows	2	3	5
Revisions in discount rates	(37)	—	(37)
Reversals	—	(5)	(5)
Change in foreign exchange rates	7	3	10
Balance, Dec. 31, 2018	407	49	456
IFRS 16 transition adjustment	**—**	**(2)**	**(2)**
Liabilities incurred	**7**	**7**	**14**
Liabilities settled	**(34)**	**(9)**	**(43)**
Accretion	**23**	**—**	**23**
Acquisition of liabilities	**16**	**3**	**19**
Disposition of liabilities	**(23)**	**(9)**	**(32)**
Revisions in estimated cash flows[(1)]	**96**	**7**	**103**
Revisions in discount rates	**16**	**—**	**16**
Reversals	**—**	**(1)**	**(1)**
Change in foreign exchange rates	**(7)**	**—**	**(7)**
Balance, Dec. 31, 2019	**501**	**45**	**546**

(1) During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. Refer to Note 3(A)(III) for further details. In addition, due to the changes in estimated useful lives, described in Note 3(A)(IV), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed. The use of a lower inflation rate decreased the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2018	407	49	456
Current portion	35	35	70
Non-current portion	372	14	386
Balance, Dec. 31, 2019	**501**	**45**	**546**
Current portion	**36**	**22**	**58**
Non-current portion	**465**	**23**	**488**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.3 billion, which will be incurred between 2020 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2019, the Corporation had provided a surety bond in the amount of US$147 million (2018 – US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2019, the Corporation had provided letters of credit in the amount of $128 million (2018 – $122 million) in support of future decommissioning obligations at the Alberta mine.

B. Other Provisions

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

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

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	**2019**			2018		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**220**	**220**	**3.5 %**	339	339	3.8 %
Debentures	**647**	**651**	**5.8 %**	647	651	5.8 %
Senior notes[3]	**905**	**914**	**5.4 %**	943	955	5.4 %
Non-recourse[4]	**1,144**	**1,157**	**4.3 %**	1,236	1,250	4.4 %
Other[5]	**154**	**162**	**7.1 %**	39	39	9.2 %
	3,070	**3,104**		3,204	3,234	
Finance lease obligations	**142**			63		
	3,212			3,267		
Less: current portion of long-term debt	**(494)**			(130)		
Less: current portion of finance lease obligations	**(19)**			(18)		
Total current long-term debt and finance lease obligations	**(513)**			(148)		
Total credit facilities, long-term debt and finance lease obligations	**2,699**			3,119		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2019 - US$ 0.7 billion (Dec. 31, 2018 - US$ 0.7 billion).
(4) Includes US$1 million at Dec. 31, 2019 (Dec. 31, 2018 - US$ 1 million).
(5) Includes US$117 at Dec. 31, 2019 (Dec. 31, 2018 - US$ 21 million) of tax equity financing.

Our credit facilities include the Corporation's $1.3 billion committed syndicated bank credit facility expiring in 2023, TransAlta Renewable's $700 million committed syndicated bank credit facility expiring in 2023 and the Corporation's three bilateral credit facilities totalling $240 million expiring in 2021. The $2.0 billion (Dec. 31, 2018 – $1.8 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, US LIBOR, or US base rate – in accordance with a pricing grid that is standard for such facilities.

During 2019, the Corporation renewed these credit facilities and TransAlta Renewables' facility was increased by $200 million to $700 million.

During 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

The Corporation has a total of $2.2 billion (Dec. 31, 2018 – $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $0.7 billion (Dec. 31, 2018 – $0.5 billion). In total, $1.3 billion (Dec. 31, 2018 – $0.9 billion) is not drawn. At Dec. 31, 2019, the $0.9 billion (Dec. 31, 2018 – $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $220 million (Dec. 31, 2018 – $339 million) and letters of credit of $690 million (Dec. 31, 2018 – $720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, the Corporation also has $411 million of available cash and cash equivalents and $17 million ($10 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030.

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040.

During 2018, the Corporation early redeemed its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross-currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

During 2017, the Corporation's US$400 million 1.90 per cent senior note matured and was paid out using existing liquidity. The repayment was hedged with a currency swap. The maturity value of the bond was $434 million.

A total of US$370 million (2018 - US$400 million) of the senior notes has been designated as a hedge of the Corporation’s net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 6.03 per cent.

During 2018, the Corporation:

- Paid out the US$25 million non-recourse debt related to its Mass Solar projects.
- Monetized the OCA and closed a $345 million bond offering through its indirect wholly owned subsidiary TransAlta OCP by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financings related to Big Level and Antrim of $122 million and Lakeswind of $23 million.

During 2019, coinciding with Antrim and Big Level each achieving commercial operation, TransAlta received tax equity funding of approximately US$91 million and US$85 million, respectively. Refer to Note 4(J) for further details.

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind acquired tax equity which was initially recognized at its fair value. Tax equity financing balances are reduced by the value of tax benefits (production tax credits and tax depreciation) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. In 2019, the Big Level and Antrim wind projects claimed accelerated (bonus) tax depreciation of $35 million in total, which was allocated to the tax equity investor, and had the effect of reducing the tax equity financing balance. The maturity dates of each financing are subject to change and primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Corporation anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim - in December 2029, 10 years from commercial operation of the projects;and Lakeswind - March 31, 2024.

TransAlta’s debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2019, the Corporation was in compliance with all debt covenants.

B. Restrictions related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and TransAlta OCP non-recourse bonds with a carrying value of $1,143 million as at Dec. 31, 2019 (Dec. 31, 2018 - $1,235 million) are subject to customary financing conditions and covenants that may restrict the Corporation’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a

debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2019. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2020. At Dec. 31, 2019, $42 million (Dec. 31, 2018 –$33 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2019.

Proceeds received from the Big Level and Antrim tax equity financing in the amount of $91 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying outstanding project development costs.

C. Security

Non-recourse debts totalling $719 million as at Dec. 31, 2019 (Dec. 31, 2018 – $766 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 include property, plant and equipment with total carrying amounts of $967 million at Dec. 31, 2019 (Dec. 31, 2018 – $1,021 million) and intangible assets with total carrying amounts of $63 million (Dec. 31, 2018 – $70 million). At Dec. 31, 2019, a non-recourse bond of approximately $119 million (Dec. 31, 2018 – $127 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds have a carrying value of $305 million (Dec. 31, 2018 – $342 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

D. Principal Repayments

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Principal repayments[1]	494	98	625	372	105	1,410	3,104
Lease obligations	19	14	9	6	4	90	142

(1) Excludes impact of derivatives.

E. Restricted Cash

At Dec. 31, 2019, the Corporation had $15 million in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in the first half of 2020.

The Corporation also had $17 million (Dec. 31, 2018 – $35 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2020. The Corporation had nil (Dec. 31, 2018 – $31 million) restricted cash related to the Kent Hills project financing.

F. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities and its two uncommitted $100 million demand letters of credit facilities. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $100 million demand letter of credit facility.

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2019 was $690 million (2018 – $720 million) with no (2018 – nil) amounts exercised by third parties under these arrangements.

24. Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into an Investment Agreement whereby Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA ("Option to Exchange"). On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions.

A. $350 Million Unsecured Subordinated Debentures

As at	Dec. 31, 2019		
	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	326	350	7%

If Brookfield chooses not to exercise its Option to Exchange as outlined below, TransAlta has the right after Dec. 31, 2028 to redeem for cash all or any portion of the Exchangeable Securities for the original subscription price, plus any accrued but unpaid interest or dividends payable, provided the minimum proceeds to Brookfield for each redemption (other than the final redemption) is not less than $100 million and provided all Exchangeable Securities must be redeemed within 36 months of the first optional redemption.

B. Option to Exchange

As at	Dec. 31, 2019	
Description	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	+35 -27

The Investment Agreement allows Brookfield the Option to Exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the Option to Exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the Option to Exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, and provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Hydro Assets, provided the 20-day volume-weighted average price ("VWAP") of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the Investment would exceed a 49 equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

25. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	**2019**	2018
Defined benefit obligation (Note 30)	**268**	227
Long-term incentive accruals (Note 29)	**4**	9
Other	**29**	51
Total	**301**	287

26. Common Shares

A. Issued and Outstanding

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

As at Dec. 31	**2019**		2018	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**284.6**	**3,059**	287.9	3,094
Purchased and cancelled under the NCIB	**(7.7)**	**(83)**	(3.3)	(35)
Stock options exercised	**0.1**	**2**	—	—
Issued and outstanding, end of year	**277.0**	**2,978**	284.6	3,059

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 deficit.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31		**2019**		2018
Total shares purchased[1]		**7,716,300**		3,264,500
Average purchase price per share	**$**	**8.80**	$	7.02
Total cost		**68**		23
Weighted average book value of shares cancelled		**83**		35
Amount recorded in deficit		**15**		12

(1) As at Dec. 31, 2019, includes 189,900 (2018 - 204,000) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019 to reflect current market practice and to reflect changes to the take-over bid regime. As required, the Shareholder Rights Plan must be put before the Corporation’s shareholders every three years for approval, and it was last approved on April 26, 2019. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Corporation’s common shares, except in limited circumstances including by way of a “permitted bid” or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	**2019**	2018	2017
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Basic and diluted weighted average number of common shares outstanding (millions)	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.86)	(0.66)

E. Dividends

On Oct. 9, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2020. On Jan. 16, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Apr. 1, 2020.

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

27. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	**2019**		2018	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series G Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Aug. 30, 2019, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2019, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (the “Series G Shares”) into Cumulative Redeemable Floating Rate Preferred Shares Series H (the “Series H Shares”), there were 140,730 Series G Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series H Shares. Therefore, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2019. As a result, the Series G Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series G Shares for the five-year period from and including Sept. 30, 2019, to, but excluding, Sept. 30, 2024, will be 4.988 per cent, which is equal to the five-year Government of Canada bond yield of 1.188 per cent, determined as of Aug. 30, 2019, plus3.80 per cent, in accordance with the terms of the Series G Shares.

II. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Sept. 17, 2017, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the “Series E Shares”) into Cumulative Redeemable Floating Rate Preferred Shares Series F (the “Series F Shares”), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017, to, but excluding, Sept. 30, 2022, will be 5.194 per cent, which is equal to the five-year Government of Canada bond yield of 1.544 per cent, determined as of Aug. 31, 2017, plus3.65 per cent, in accordance with the terms of the Series E Shares.

III. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion
On June 16, 2017, the Corporation announced that, after taking into account all election notices received by the June 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017, to, but excluding, June 30, 2022, will be 4.027 per cent, which is equal to the five-year Government of Canada bond yield of 0.927 per cent, determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

IV. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion
On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation had 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2019.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on the 90-day Treasury Bill rate plus 2.03 per cent.

V. Preferred Share Series Information
The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2019, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.67725	March 31, 2021	2.03	B
B	Floating	0.93575	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29850	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.32500	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of preferred share dividends declared in 2019, 2018 and 2017:

	Total dividends declared		
Series	**2019**	2018	2017
A	**5**	9	5
B	**1**	1	1
C	**8**	14	9
E	**9**	15	8
G	**7**	11	7
Total for the year	**30**	50	30

28. Accumulated Other Comprehensive Income

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2019	2018
Currency translation adjustment		
Opening balance, Jan. 1	**17**	(26)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(59)**	84
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**21**	(41)
Balance, Dec. 31	**(21)**	17
Cash flow hedges		
Opening balance, Jan. 1	**508**	562
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[1]	**19**	(54)
Balance, Dec. 31	**527**	508
Employee future benefits		
Opening balance, Jan. 1	**(29)**	(44)
Net actuarial gains (losses) on defined benefit plans, net of tax[2]	**(26)**	15
Balance, Dec. 31	**(55)**	(29)
Other		
Opening balance, Jan. 1	**(15)**	(3)
Change in ownership of TransAlta Renewables	**1**	4
Intercompany investments at FVOCI	**17**	(16)
Balance, Dec. 31	**3**	(15)
Accumulated other comprehensive income	**454**	481

(1) Net of income tax of $ 6 million for the year ended Dec. 31, 2019 (2018 - $ 12 million).
(2) Net of income tax of $ 7 million for the year ended Dec. 31, 2019 (2018 - $ 5 million).

29. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares.

During 2019, as a result of the Corporation's change in its intended settlement policy, the accounting classification of the RSUs and PSUs changed from cash-settled to equity-settled. The RSUs and PSUs have been accounted for as equity-settled grants from the dates of the policy change, with fair values determined as at that date. On average, the fair value of outstanding grants used in accounting for the change was $8.29, measured using the black-scholes option pricing model. As a result of this change, the liability for the cash-settled grants ($25 million) has been derecognized and the equity-settled fair value ($24 million) has been recognized in contributed surplus, with the net difference of $1 million representing the cumulative change in compensation expense. No changes were made to the vesting or performance conditions associated with the awards. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expenses related to this plan are recognized during the period earned, with the corresponding amounts due under the plan recorded in contributed surplus (2018 - liabilities). Prior to this change, the liability was valued at the end of each reporting period using the closing price of the Corporation's common shares on the TSX.

The pre-tax compensation expense related to PSUs and RSUs in 2019 was $19 million (2018 - $8 million, 2017 - $15 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $2 million in 2019 (2018 - nil, 2017 - $1 million).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2019, the Corporation granted executive officers of the Corporation a total of 1.4 million stock options with a weighted average exercise price of $5.65 that vest after a three-year period and expire 7 years after issuance (2018 - 0.7 million stock options at $7.45; 2017 - 0.7 million stock options at $7.25). The expense recognized relating to these grants during 2019 was approximately $1 million (2018 - approximately $1 million, 2017 - approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2019, are outlined below:

	Options outstanding		
Range of exercise prices[1] *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 9.00	**3.3**	4.7	**6.34**
22.00 - 30.00	**0.5**	**0.1**	**23.44**
5.00 - 30.00	**3.8**	**4.2**	**8.41**

(1) Options currently exercisable as at Dec. 31, 2019 .

30. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the US covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2019. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2019.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the US. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation posted a letter of credit in March 2019 for the amount of $83 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2018, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2019.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**1**	**10**
Administration expenses	**2**	**—**	**—**	**2**
Interest cost on defined benefit obligation	**19**	**3**	**1**	**23**
Interest on plan assets	**(12)**	**(1)**	**—**	**(13)**
Curtailment and amendment gain	**(3)**	**—**	**—**	**(3)**
Defined benefit expense	**13**	**4**	**2**	**19**
Defined contribution expense	**9**	**—**	**—**	**9**
Net expense	**22**	**4**	**2**	**28**

Year ended Dec. 31, 2018	Registered	Supplemental	Other	Total
Current service cost	9	2	1	12
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	18	3	1	22
Interest on plan assets	(13)	—	—	(13)
Defined benefit expense	15	5	2	22
Defined contribution expense	10	—	—	10
Net expense	25	5	2	32

Year ended Dec. 31, 2017	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	20	3	1	24
Interest on plan assets	(15)	—	—	(15)
Defined benefit expense	14	5	2	21
Defined contribution expense	11	—	—	11
Net expense	25	5	2	32

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**373**	**13**	**—**	**386**
Present value of defined benefit obligation	**(543)**	**(99)**	**(22)**	**(664)**
Funded status – plan deficit	**(170)**	**(86)**	**(22)**	**(278)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(3)**	**(5)**	**(2)**	**(10)**
Other long-term liabilities	**(167)**	**(81)**	**(20)**	**(268)**
Total amount recognized	**(170)**	**(86)**	**(22)**	**(278)**

As at Dec. 31, 2018	Registered	Supplemental	Other	Total
Fair value of plan assets	368	13	—	381
Present value of defined benefit obligation	(514)	(80)	(25)	(619)
Funded status – plan deficit	(146)	(67)	(25)	(238)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(5)	(5)	(1)	(11)
Other long-term liabilities	(141)	(62)	(24)	(227)
Total amount recognized	(146)	(67)	(25)	(238)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
As at Dec. 31, 2017	416	12	—	428
Interest on plan assets	13	—	—	13
Net return on plan assets	(25)	—	—	(25)
Contributions	5	6	1	12
Benefits paid	(42)	(5)	(1)	(48)
Administration expenses	(1)	—	—	(1)
Effect of translation on US plans	2	—	—	2
As at Dec. 31, 2018	368	13	—	381
Interest on plan assets	**12**	**1**	**—**	**13**
Net return on plan assets	**40**	**—**	**—**	**40**
Contributions	**6**	**4**	**1**	**11**
Benefits paid	**(50)**	**(5)**	**(1)**	**(56)**
Administration expenses	**(2)**	**—**	**—**	**(2)**
Effect of translation on US plans	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2019	**373**	**13**	**—**	**386**

The fair value of the Corporation's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2019	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**66**	**—**	**66**
US	**—**	**28**	**—**	**28**
International	**—**	**102**	**—**	**102**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**40**	**—**	**40**
AA	**—**	**68**	**—**	**68**
A	**—**	**37**	**—**	**37**
BBB	**1**	**21**	**—**	**22**
Below BBB	**—**	**3**	**—**	**3**
Money market and cash and cash equivalents	**—**	**19**	**—**	**19**
Total	**1**	**384**	**1**	**386**

Year ended Dec. 31, 2018	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	65	—	65
US	—	26	—	26
International	—	101	—	101
Private	—	—	1	1
Bonds				
AAA	—	48	—	48
AA	—	64	—	64
A	—	39	—	39
BBB	1	21	—	22
Below BBB	—	3	—	3
Money market and cash and cash equivalents	(2)	14	—	12
Total	(1)	381	1	381

Plan assets do not include any common shares of the Corporation at Dec. 31, 2019, and Dec. 31, 2018. The Corporation charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2019 (2018 - $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2017	561	87	27	675
Current service cost	9	2	1	12
Interest cost	18	3	1	22
Benefits paid	(42)	(5)	(1)	(48)
Actuarial gain arising from demographic assumptions	—	—	—	—
Actuarial loss arising from financial assumptions	(35)	(7)	(2)	(44)
Actuarial gain (loss) arising from experience adjustments	—	—	(1)	(1)
Effect of translation on US plans	3	—	—	3
Present value of defined benefit obligation as at Dec. 31, 2018	514	80	25	619
Current service cost	**7**	**2**	**1**	**10**
Interest cost	**19**	**3**	**1**	**23**
Benefits paid	**(51)**	**(4)**	**(1)**	**(56)**
Curtailment	**(3)**	**—**	**—**	**(3)**
Actuarial loss arising from demographic assumptions	**—**	**—**	**(2)**	**(2)**
Actuarial (gain) loss arising from financial assumptions	**57**	**9**	**2**	**68**
Actuarial (gain) loss arising from experience adjustments	**2**	**9**	**(4)**	**7**
Effect of translation on US plans	**(2)**	**—**	**—**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2019	**543**	**99**	**22**	**664**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2019, is15.6 years.

F. Contributions

The expected employer contributions for 2020 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**4**	**5**	**1**	**10**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2019			As at Dec. 31, 2018		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.0**	**3.0**	**3.0**	3.9	3.8	3.9
Rate of compensation increase	**2.8**	**3.0**	**—**	2.5	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation[1][3]	**—**	**—**	**7.0**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.9**	**3.8**	**3.9**	3.3	3.3	3.4
Rate of compensation increase	**2.5**	**3.0**	**—**	2.6	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation[2][4]	**—**	**—**	**7.4**	—	—	7.6
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health-care premium escalation	**—**	**—**	**—**	—	—	—

(1) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2030 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(3) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(4) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			US plans	
Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**84**	**15**	**2**	**3**	**1**
1% increase in the salary scale	**14**	**—**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**22**	**3**	**—**	**1**	**—**

31. Joint Arrangements

Joint arrangements at Dec. 31, 2019, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Heartland Generation Ltd., an affiliate of Energy Capital Partners
Pioneer Pipeline	Coal	50	Natural gas pipeline in Alberta operated by Tidewater
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

32. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2019	2018	2017
(Use) source:			
Accounts receivable	**261**	58	(228)
Prepaid expenses	**—**	19	(75)
Income taxes receivable	**(6)**	—	8
Inventory	**(13)**	(21)	(7)
Accounts payable, accrued liabilities and provisions	**(130)**	(97)	186
Income taxes payable	**9**	(3)	2
Change in non-cash operating working capital	**121**	(44)	(114)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2018	Net cash flows	New leases	Tax shield on tax equity financing	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2019
Long-term debt and lease obligations	3,267	**(70)**	**133**	**(35)**	—	**(42)**	**(41)**	**3,212**
Exchangeable securities	—	**350**	—	—	—	—	(24)	**326**
Dividends payable (common and preferred)	58	**(85)**	—	—	**64**	—	—	**37**
Total liabilities from financing activities	3,325	**195**	**133**	**(35)**	**64**	**(42)**	**(65)**	**3,575**

	Balance Dec. 31, 2017	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2018
Long-term debt and finance lease obligations	3,707	(540)	10	—	95	(5)	3,267
Dividends payable (common and preferred)	34	(86)	—	107	—	3	58
Total liabilities from financing activities	3,741	(626)	10	107	95	(2)	3,325

33. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2019	2018	Increase/ (decrease)
Long-term debt[1]	**3,212**	3,267	**(55)**
Exchangeable securities	**326**	—	**326**
Equity			
Common shares	**2,978**	3,059	**(81)**
Preferred shares	**942**	942	**—**
Contributed surplus	**42**	11	**31**
Deficit	**(1,455)**	(1,496)	**41**
Accumulated other comprehensive income	**454**	481	**(27)**
Non-controlling interests	**1,101**	1,137	**(36)**
Less: available cash and cash equivalents[2]	**(411)**	(89)	**(322)**
Less: principal portion of restricted cash on TransAlta OCP Bonds[3]	**(10)**	(27)	**17**
Less: fair value asset of hedging instruments on long-term debt[4]	**(7)**	(10)	**3**
Total capital	**7,172**	7,275	**(103)**

(1) Includes lease obligations, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.
(2) The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available and used to facilitate repayment of debt.
(3) The Corporation includes the principal portion of restricted cash on TransAlta OCP bonds because this cash is restricted specifically to repay outstanding debt.
(4) The Corporation includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Corporation's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain a strong financial position that enables the Corporation to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles. The Corporation has an investment-grade credit rating from DBRS (stable outlook). In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised their rating outlook to stable from positive. During 2019, Fitch Ratings downgraded the Corporation below investment grade to BB+ with a stable outlook; DBRS reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's downgraded the Corporation's Unsecured Debt rating and Issuer Rating to BB+ with stable outlook. The Corporation remains focused on strengthening its financial position and cash flow coverage ratios. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing.

Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. These ratios are summarized in the table below:

As at Dec. 31	2019	2018	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.5**	4.8	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**19.0**	20.8	20 to 25
Adjusted net debt to adjusted comparable earnings before interest, taxes, depreciation and amortization (times)	**3.9**	3.6	3.0 to 3.5

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO less the termination payments for the Sundance B and C PPAs plus interest on debt, exchangeable securities and lease obligations (net of capitalized interest) divided by interest on debt, exchangeable securities and lease obligations (net of capitalized interest) plus 50 per cent of dividends paid on preferred shares. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less the termination payments for the Sundance B and C PPAs less 50 per cent of dividends paid on preferred shares divided by adjusted net debt (current and long-term debt plus exchangeable securities plus 50 per cent of outstanding preferred shares less available cash and cash equivalents less principal portion of TransAlta OCP restricted cash and including fair value assets of hedging instruments on debt). The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Adjusted Comparable Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is calculated as adjusted net debt divided by adjusted comparable EBITDA. Adjusted comparable EBITDA is calculated as earnings before interest, taxes, depreciation and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations as well as the termination payments for the Sundance B and C PPAs. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified ranges while the Corporation executes its coal-to-gas transition and growth strategy, but we remain focused on maintaining a strong balance sheet.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, Invest in PP&E and Make Acquisitions

For the years ended Dec. 31, 2019 and 2018, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	**2019**	2018	**Increase (decrease)**
Cash flow from operating activities	**849**	820	**29**
Change in non-cash working capital	**(121)**	44	**(165)**
Cash flow from operations before changes in working capital	**728**	864	**(136)**
Dividends paid on common shares	**(45)**	(46)	**1**
Dividends paid on preferred shares	**(40)**	(40)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(106)**	(165)	**59**
Property, plant and equipment expenditures	**(417)**	(277)	**(140)**
Inflow	**120**	336	**(216)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2019, $.3 billion (2018 - $0.9 billion) of the Corporation's available credit facilities were not drawn.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

34. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2019, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables	Canada	60.4	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2019	2018	2017
Total compensation	**30**	17	24
Comprised of:			
Short-term employee benefits	**13**	11	14
Post-employment benefits	**2**	2	2
Termination benefits	**2**	—	—
Share-based payments	**13**	4	8

35. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas, transportation and other contracts	125	125	120	128	131	1,493	**2,122**
Transmission	9	5	4	3	—	—	**21**
Coal supply and mining agreements	147	16	16	16	8	14	**217**
Long-term service agreements	50	22	32	17	15	14	**150**
Operating leases	4	2	2	2	3	64	**77**
Growth	535	254	196	270	13	—	**1,268**
TransAlta Energy Transition Bill	6	6	6	6	—	—	**24**
Total	**876**	**430**	**376**	**442**	**170**	**1,585**	**3,879**

A. Natural Gas, Transportation and Other Contracts

Includes fixed price or volume natural gas purchase and transportation contracts. Other contracts relate to commitments for goods and services.

B. Transmission

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2020.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness joint operation, and certain other mining royalty agreements. Some of these commitments have been reduced due to the cessation of coal-fired emissions from the Sheerness coal-fired plant on or before Dec. 31, 2030.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities and turbines at various wind facilities.

E. Operating Leases

Includes lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Prior to the adoption of IFRS 16 (refer to Note 3(A)(I) for further details), operating lease expenses were recognized as incurred in the statement of earnings. During the year ended Dec. 31, 2018, $8 million (2017 - $7 million) was recognized as an expense in respect of operating leases. Sublease payments received during 2019, 2018 and 2017 were less than $1 million. No contingent rental payments were made in respect of operating leases.

F. Growth

Commitments for growth relate to the following projects: coal-to-gas conversions and repowering Sudance Unit 5, Kaybob cogeneration, Windrise, Windcharger and Skookumchuck and any final costs associated with the Big Level and Antrim projects. Refer to Note 4 for further details on these projects.

G. TransAlta Energy Transition Bill Commitments

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement, we have committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required. As of Dec. 31, 2019, the Corporation has funded approximately US$37 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding
The Corporation has been participating in a line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016 and issue a single invoice charging or crediting market participants for the difference in losses charges. A more recent decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was to be issued in April 2021, with cash settlement expected in June 2021. The current total estimate of exposure based on known data is approximately $12 million. However, the AESO recently requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, resulting in invoices being issued as early as April 2020 for settlement in June 2020, a year earlier than anticipated. The Corporation is challenging this request.

II. FMG Disputes
The Corporation is currently engaged in two disputes with FMG. The first dispute arose as a result of FMG's attempted termination of the South Hedland PPA on the basis that the conditions to establishing commercial operation under the South Hedland PPA had not been met. TransAlta's view is that all conditions to establishing commercial operation under the terms of the South Hedland PPA had been satisfied in full. TransAlta initiated legal action against FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. This matter is scheduled to proceed to trial beginning June 15, 2020.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

III. Mangrove Claim
On April 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming the Corporation, the incumbent members of the Board on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is alleging, among other things, oppression by the Corporation and the named Directors and is seeking to set aside the 2019 Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020.

IV. Keephills 1 Superheater
Keephills Unit 1 was taken offline from Mar. 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool is attempting to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. TransAlta denied the Balancing Pool had the right to do so. The Alberta Court of Queen's Bench confirmed that the Balancing Pool has a right under the PPA to commence an arbitration, independent of the PPA buyer. On Sept. 4, 2019, the Alberta Court of Appeal upheld the lower court's decision. TransAlta sought permission to appeal the Alberta's Court of Appeal's decision to the Supreme Court of Canada. The application was denied and the matter will now proceed to arbitration, with a hearing potentially sometime in 2020.

V. Sundance A Decommissioning
TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the mine. The Balancing Pool filed a statement of intent to participate as an intervener because it disagrees that, amongst other things, the mine decommissioning costs should be included. TransAlta anticipates it will receive payment from the Balancing Pool in 2020 for its decommissioning costs; however, the amount is uncertain.

VI. Hydro PPA Renewable Energy Credits
The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $27 million, earned by the Hydro plants under the *Carbon Competitiveness Incentive Regulation* in 2018 and 2019. Refer to Note 2(A) and 2(F)(IV) for the accounting policies on these credits. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. The Corporation anticipates this dispute will be resolved by the end of 2021.

VII. Direct Assigned Capital Deferral Account Application
AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 direct assigned capital deferral account for the Edmonton region 240 kV line upgrades project (the "Proceeding"). TransAlta is a secondary applicant in the Proceeding. Altalink and TransAlta seek to have their costs approved by the AUC as reasonable and prudent. The Enoch Cree Nation ("ECN") and the Consumers' Coalition of Alberta are registered participants in the Proceeding. Currently Altalink, ECN and TransAlta's interests are closely aligned. TransAlta believes it has a reasonable chance of having its costs (estimated at about $21 million) approved.

36. Segment Disclosures

A. Description of Reportable Segments

The Corporation has eight reportable segments as described in Note 1.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	816	571	209	160	312	156	129	(6)	2,347
Fuel, carbon compliance and purchased power	570	416	74	9	16	7	—	(6)	1,086
Gross margin	246	155	135	151	296	149	129	—	1,261
Operations, maintenance and administration	138	67	44	37	50	36	30	73	475
Depreciation and amortization	233	83	41	48	124	32	2	27	590
Asset impairment charge (reversal)	15	(10)	—	—	—	2	—	18	25
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	(88)	—	—	—	—	—	—	—	(88)
Taxes, other than income taxes	13	3	1	—	8	3	—	1	29
Termination of Sundance B and C PPAs	(56)	—	—	—	—	—	—	—	(56)
Net other operating expense (income)	(40)	—	(1)	—	(10)	—	—	2	(49)
Operating income (loss)	31	12	50	66	124	76	97	(121)	335
Finance lease income	—	—	6	—	—	—	—	—	6
Net interest expense									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	442	232	165	282	156	67	(7)	2,249
Fuel, carbon compliance and purchased power	666	314	96	8	17	6	—	(7)	1,100
Gross margin	246	128	136	157	265	150	67	—	1,149
Operations, maintenance and administration	171	61	48	37	50	38	24	86	515
Depreciation and amortization	241	74	43	49	110	30	2	25	574
Asset impairment charge	38	—	—	—	12	—	—	23	73
Taxes, other than income taxes	13	5	1	—	8	3	—	1	31
Termination of Sundance B and C PPAs (Note 9)	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(41)	—	—	—	(6)	—	—	—	(47)
Operating income (loss)	(19)	(12)	44	71	91	79	41	(135)	160
Finance lease income	—	—	8	—	—	—	—	—	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets									1
Earnings before income taxes									(96)

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	999	435	261	135	287	121	69	—	2,307
Fuel, carbon compliance and purchased power	585	293	101	14	17	6	—	—	1,016
Gross margin	414	142	160	121	270	115	69	—	1,291
Operations, maintenance and administration	192	51	50	31	48	37	24	84	517
Depreciation and amortization	317	73	38	37	111	31	2	26	635
Asset impairment reversals	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	13	4	1	—	8	3	—	1	30
Net other operating income	(40)	—	(9)	—	—	—	—	—	(49)
Operating income (loss)	(88)	14	80	53	103	44	43	(111)	138
Finance lease income	—	—	11	43	—	—	—	—	54
Net interest expense									(247)
Foreign exchange loss									(1)
Gain on sale of assets									2
Earnings before income taxes									(54)

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
PP&E	**2,540**	**352**	**392**	**489**	**1,947**	**469**	**1**	**17**	**6,207**
Right of use assets	**68**	**—**	**—**	**4**	**56**	**6**	**—**	**12**	**146**
Intangible assets	**41**	**6**	**2**	**37**	**173**	**5**	**9**	**45**	**318**
Goodwill	—	—	—	—	**176**	**258**	**30**	**—**	**464**

As at Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
PP&E	2,587	332	391	554	1,799	481	1	19	6,164
Intangible assets	81	7	4	41	173	4	11	52	373
Goodwill	**—**	**—**	**—**	**—**	175	259	30	**—**	464

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	**114**	**8**	**36**	**6**	**229**	**23**	**—**	**1**	**417**
Intangible assets	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**12**	**14**

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	101	14	21	6	117	16	—	2	277
Intangible assets	3	—	—	—	—	—	—	17	20

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	116	35	31	114	20	16	—	6	338
Intangible assets	5	1	—	29	—	—	—	16	51

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

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

Year ended Dec. 31	2019	2018	2017
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**590**	574	635
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**119**	136	73
Depreciation and amortization on the Consolidated Statements of Cash Flows	**709**	710	708

C. Geographic Information

I. Revenues

Year ended Dec. 31	2019	2018	2017
Canada	**1,460**	1,573	1,663
US	**727**	511	509
Australia	**160**	165	135
Total revenue	**2,347**	2,249	2,307

II. Non-Current Assets

	Property, plant and equipment		Right of use assets		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Canada	**4,854**	4,953	**109**	—	**213**	273	**75**	101	**418**	417
US	**863**	657	**33**	—	**68**	59	**47**	50	**46**	47
Australia	**490**	554	**4**	—	**37**	41	**76**	83	**—**	—
Total	**6,207**	6,164	146	—	**318**	373	**198**	234	**464**	464

D. Significant Customer

During the year ended Dec. 31, 2019, sales to one customer represented11 per cent of the Corporation's total revenue (2018 - one customer represented19 per cent).

Exhibit 1

(Unaudited)

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2019:

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

1.48 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.

Exhibit 23.1

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the reference of our Firm under the caption “Experts”, and to the incorporation by reference in the following Registration Statements:

1. Form S-8 No. 333-72454 and No. 333-101470 pertaining to TransAlta Corporation’s Share Option Plan

2. Form F-10 No. 333-229991 pertaining to the registration of Debt and Equity Securities

of TransAlta Corporation and the use herein of our reports dated March 3, 2020, with respect to the consolidated statements of financial position as at December 31, 2019 and 2018 and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three year period ended December 31, 2019, and the effectiveness of internal control over financial reporting of TransAlta Corporation as of December 31, 2019, included in this Annual Report on Form 40-F.

/s/Ernst & Young LLP
Chartered Professional Accountants

Calgary, Alberta
March 3, 2020

A member firm of Ernst & Young Global Limited

Exhibit 31.1

Certifications

I, Dawn L. Farrell, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

March 3, 2020

/s/ Dawn L. Farrell

Dawn L. Farrell

President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Todd Stack, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

March 3, 2020

/s/ Todd Stack

Todd Stack

Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dawn L. Farrell, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Dawn L. Farrell

Dawn L. Farrell

President and Chief Executive Officer

Dated: March 3, 2020

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Todd Stack, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Todd Stack

Todd Stack

Chief Financial Officer

Dated: March 3, 2020

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.