TransAlta Corporation

Consolidated Financial Statements

December 31, 2017

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

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

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

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

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

March 1, 2018

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).*

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

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

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

TransAlta proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2017 consolidated financial statements of TransAlta included $624 million and $550 million of total and net assets, respectively, as of December 31, 2017, and $160 million and $9 million of revenues and net loss, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at December 31, 2017, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended December 31, 2017, 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	**Donald Tremblay**
President and Chief Executive Officer	Chief Financial Officer

March 1, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

Opinions on the Internal Control over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2017, 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, 2017, 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 as at December 31, 2017 and 2016, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three-year period ended December 31, 2017 of TransAlta Corporation and our report dated March 1, 2018 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 the TransAlta Corporation in accordance with the U.S. 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 standard of the PCAOB. The standards of the PCAOB 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 corporation'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 by the International Accounting Standards Boards. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the corporation's assets that could have a material effect on the financial statements.

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2017 consolidated financial statements of TransAlta Corporation and constituted $624 million and $550 million of total and net assets, respectively, as of December 31, 2017, and $160 million and $9 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 1, 2018

Independent Auditors’ Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of TransAlta Corporation , which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, and the consolidated statements of earnings (loss), consolidated statements of comprehensive income (loss), consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the “consolidated financial statements”).

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransAlta Corporation as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the three years ended December 31, 2017, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also 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, 2017, based on the 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 1, 2018 expressed an unqualified opinion on the effectiveness of TransAlta Corporation’s internal control over financial reporting.

Basis for Opinion

Management's responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors’ responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and 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 from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to TransAlta Corporation in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the TransAlta Corporation’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a reasonable basis for our audit opinion.

We have served as the Corporation’s auditor since 1947.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 1, 2018

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2017**	2016	2015
Revenues *(Note 33)*	**2,307**	2,397	2,267
Fuel and purchased power *(Note 5)*	**1,016**	963	1,008
Gross margin	**1,291**	1,434	1,259
Operations, maintenance, and administration *(Note 5)*	**517**	489	492
Depreciation and amortization	**635**	601	545
Asset impairment charges (reversals) *(Note 6)*	**20**	28	(2)
Restructuring provision *(Note 4)*	**—**	1	22
Taxes, other than income taxes	**30**	31	29
Net other operating (income) losses *(Note 8)*	**(49)**	(194)	25
Operating income	**138**	478	148
Finance lease income *(Note 7)*	**54**	66	58
Net interest expense *(Note 9)*	**(247)**	(229)	(251)
Foreign exchange gain (loss)	**(1)**	(5)	4
Gain on sale of assets and other *(Note 4)*	**2**	4	262
Earnings (loss) before income taxes	**(54)**	314	221
Income tax expense *(Note 10)*	**64**	38	105
Net earnings (loss)	**(118)**	276	116
Net earnings (loss) attributable to:			
TransAlta shareholders	**(160)**	169	22
Non-controlling interests *(Note 11)*	**42**	107	94
	(118)	276	116
Net earnings (loss) attributable to TransAlta shareholders	**(160)**	169	22
Preferred share dividends *(Note 24)*	**30**	52	46
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Weighted average number of common shares outstanding in the year *(millions)*	**288**	288	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 23)*	**(0.66)**	0.41	(0.09)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2017**	2016	2015
Net earnings (loss)	**(118)**	276	116
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**(6)**	8	4
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**(1)**	(1)	3
Total items that will not be reclassified subsequently to net earnings	**(7)**	7	7
Gains (losses) on translating net assets of foreign operations, net of tax[3]	**(80)**	(71)	247
Reclassification of translation gains on net assets of divested foreign operations[4] *(Note 4)*	**(9)**	—	(10)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[5]	**50**	18	(172)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[6] *(Note 4)*	**14**	—	6
Gains on derivatives designated as cash flow hedges, net of tax[7]	**214**	179	375
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[8]	**(107)**	(48)	(194)
Total items that will be reclassified subsequently to net earnings	**82**	78	252
Other comprehensive income	**75**	85	259
Total comprehensive income (loss)	**(43)**	361	375
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(74)**	215	272
Non-controlling interests *(Note 11)*	**31**	146	103
	(43)	361	375

(1) Net of income tax recovery of 4 for the year ended Dec. 31, 2017 (2016 - 4 expense, 2015 - nil).
(2) Net of income tax expense of nil for the year ended Dec. 31, 2017 (2016 - nil , 2015 - 1 expense).
(3) Net of income tax expense of nil for the year ended Dec. 31, 2017 (2016 - 11, 2015 - nil).
(4) Net of reclassification of income tax expense of 11 for the year ended Dec. 31, 2017 (2016 - nil, 2015 - nil).
(5) Net of income tax expense of 2 for the year ended Dec. 31, 2017 (2016 - 5 expense, 2015 - 7 expense).
(6) Net of reclassification of income tax recovery of 2 for the year ended Dec. 31, 2017 (2016 - nil recovery, 2015 - 1 recovery).
(7) Net of income tax recovery of 77 for the year ended Dec. 31, 2017 (2016 - 92 expense, 2015 - 138 expense).
(8) Net of reclassification of income tax expense of 31 for the year ended Dec. 31, 2017 (2016 - 41 expense, 2015 - 50 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2017**	2016
Cash and cash equivalents	**314**	305
Trade and other receivables *(Note 12)*	**933**	703
Prepaid expenses	**24**	23
Risk management assets *(Notes 13 and 14)*	**219**	249
Inventory *(Note 15)*	**219**	213
Assets held for sale *(Note 4)*	**—**	61
	1,709	1,554
Restricted cash *(Note 21)*	**30**	—
Long-term portion of finance lease receivables *(Note 7)*	**215**	719
Property, plant, and equipment *(Note 16)*		
Cost	**12,973**	12,773
Accumulated depreciation	**(6,395)**	(5,949)
	6,578	6,824
Goodwill *(Note 17)*	**463**	464
Intangible assets (Note 18)	**364**	355
Deferred income tax assets *(Note 10)*	**24**	53
Risk management assets *(Notes 13 and 14)*	**684**	785
Other assets *(Note 19)*	**237**	242
Total assets	**10,304**	10,996
Accounts payable and accrued liabilities	**595**	413
Current portion of decommissioning and other provisions *(Note 20)*	**67**	39
Risk management liabilities *(Notes 13 and 14)*	**101**	66
Income taxes payable	**64**	6
Dividends payable *(Note 23)*	**34**	54
Current portion of long-term debt and finance lease obligations *(Note 21)*	**747**	639
	1,608	1,217
Credit facilities, long-term debt, and finance lease obligations *(Note 21)*	**2,960**	3,722
Decommissioning and other provisions *(Note 20)*	**403**	304
Deferred income tax liabilities *(Note 10)*	**549**	712
Risk management liabilities *(Notes 13 and 14)*	**40**	48
Defined benefit obligation and other long-term liabilities *(Note 22)*	**359**	330
Equity		
Common shares *(Note 23)*	**3,094**	3,094
Preferred shares *(Note 24)*	**942**	942
Contributed surplus	**10**	9
Deficit	**(1,209)**	(933)
Accumulated other comprehensive income *(Note 25)*	**489**	399
Equity attributable to shareholders	**3,326**	3,511
Non-controlling interests *(Note 11)*	**1,059**	1,152
Total equity	**4,385**	4,663
Total liabilities and equity	**10,304**	10,996

Commitments and contingencies *(Note 32)*

Subsequent events *(Note 34)*

See accompanying notes.

Gordon D. Giffin   Alan J. Fohrer

On behalf of the Board: Gordon D. Giffin, Director   Alan J. Fohrer, Director

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, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings	–	–	–	169	–	169	107	276
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	(53)	(53)	–	(53)
Net gains on derivatives designated as cash flow hedges, net of tax	–	–	–	–	106	106	24	130
Net actuarial gains on defined benefits plans, net of tax	–	–	–	–	8	8	–	8
Intercompany available-for-sale investments	–	–	–	–	(15)	(15)	15	–
Total comprehensive income				169	46	215	146	361
Common share dividends	–	–	–	(58)	–	(58)	–	(58)
Preferred share dividends	–	–	–	(52)	–	(52)	–	(52)
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	–	–	–	26	–	26	138	164
Distributions paid, and payable, to non-controlling interests	–	–	–	–	–	–	(161)	(161)
Common shares issued	19	–	–	–	–	19	–	19
Balance, Dec 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings (loss)	**–**	**–**	**–**	(160)	**–**	**(160)**	42	**(118)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**–**	**–**	**–**	**–**	**(25)**	**(25)**	**–**	**(25)**
Net gains on derivatives designated as cash flow hedges, net of tax	**–**	**–**	**–**	**–**	**106**	**106**	**–**	**106**
Net actuarial gains on defined benefits plans, net of tax	**–**	**–**	**–**	**–**	(6)	**(6)**	**–**	**(6)**
Intercompany available-for-sale investments	**–**	**–**	**–**	**–**	**11**	**11**	**(11)**	**–**
Total comprehensive income				**(160)**	**86**	**(74)**	**31**	**(43)**
Common share dividends	**–**	**–**	**–**	**(34)**	**–**	**(34)**	**–**	**(34)**
Preferred share dividends	**–**	**–**	**–**	**(30)**	**–**	**(30)**	**–**	**(30)**
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	**–**	**–**	**–**	**(52)**	**4**	**(48)**	**48**	**–**
Effect of share-based payment plans	**–**	**–**	**1**	**–**	**–**	**1**	**–**	**1**
Distributions paid, and payable, to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(172)**	**(172)**
Balance, Dec 31, 2017	**3,094**	**942**	**10**	**(1,209)**	**489**	**3,326**	**1,059**	**4,385**

(1) Refer to Note 25 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)*	**2017**	2016	2015
Operating activities			
Net earnings (loss)	**(118)**	276	116
Depreciation and amortization *(Note 33)*	**708**	664	605
Gain on sale of assets *(Note 4)*	**(1)**	(1)	(262)
Accretion of provisions *(Note 20)*	**23**	20	21
Decommissioning and restoration costs settled *(Note 20)*	**(19)**	(23)	(24)
Deferred income tax expense (recovery) *(Note 10)*	**(15)**	15	86
Unrealized (gain) loss from risk management activities	**(48)**	58	61
Unrealized foreign exchange (gain) loss	**22**	(1)	13
Provisions	**(7)**	(123)	101
Asset impairment charges (reversals) *(Note 6)*	**20**	28	(2)
Other non-cash items	**175**	(242)	(41)
Cash flow from operations before changes in working capital	**740**	671	674
Change in non-cash operating working capital balances *(Note 29)*	**(114)**	73	(242)
Cash flow from operating activities	**626**	744	432
Investing activities			
Additions to property, plant, and equipment *(Notes 16 and 33)*	**(338)**	(358)	(476)
Additions to intangibles *(Notes 18 and 33)*	**(51)**	(21)	(26)
Restricted cash *(Notes 19 and 21)*	**(30)**	—	—
Loan receivable *(Note 19)*	**(38)**	—	—
Acquisition of renewable energy facilities, net of cash acquired *(Note 4)*	**—**	—	(101)
Proceeds on sale of property, plant, and equipment	**3**	6	7
Proceeds on sale of Wintering Hills facility and Solomon disposition *(Note 4)*	**478**	—	—
Income tax expense on Solomon disposition *(Notes 4 and 10)*	**(56)**	—	—
Realized gains (losses) on financial instruments	**6**	(6)	(12)
Decrease in finance lease receivable	**59**	56	23
Other	**(3)**	2	24
Change in non-cash investing working capital balances	**57**	(6)	(12)
Cash flow from (used in) investing activities	**87**	(327)	(573)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 21)*	**26**	(315)	218
Repayment of long-term debt *(Note 21)*	**(814)**	(88)	(758)
Issuance of long-term debt *(Note 21)*	**260**	361	487
Dividends paid on common shares *(Note 23)*	**(46)**	(69)	(124)
Dividends paid on preferred shares *(Note 24)*	**(40)**	(42)	(46)
Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)*	**—**	162	404
Realized gains (losses) on financial instruments	**106**	(2)	87
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(172)**	(151)	(99)
Decrease in finance lease obligations *(Note 21)*	**(17)**	(16)	(13)
Other	**(6)**	(3)	(7)
Cash flow from (used in) financing activities	**(703)**	(163)	149
Cash flow from operating, investing, and financing activities	**10**	254	8
Effect of translation on foreign currency cash	**(1)**	(3)	3
Increase in cash and cash equivalents	**9**	251	11
Cash and cash equivalents, beginning of year	**305**	54	43
Cash and cash equivalents, end of year	**314**	305	54
Cash income taxes paid	**14**	27	17
Cash interest paid	**230**	235	242

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

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

II. Energy Marketing Segment

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

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

III. Corporate

The Corporate segment includes the Corporation's central financial, legal, administrative, and investor relation functions. 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 March 1, 2018.

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

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. Revenues associated with leases are recognized as outlined in Note 2(R).

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

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. Available-for-sale 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. Available-for-sale 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. Derivatives used in commodity risk management activities are described in more detail in Note 2(A).

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.

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 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.

a. 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.

b. 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 transactions 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.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

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

D. Cash and Cash Equivalents

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

E. Collateral Paid and Received

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

F. Inventory

I. Fuel

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

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

II. Energy Marketing

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

III. Parts and Materials

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

G. Property, Plant, and Equipment

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

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

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized.

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value, or depreciation method is accounted for prospectively.

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

Coal generation	2-14 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	2-14 years
Capital spares and other	2-30 years

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

H. Intangible Assets

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

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

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

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

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

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

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

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

P. Emission Credits and Allowances

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

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

Q. Assets Held for Sale

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

R. Leases

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

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

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

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

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

S. Borrowing Costs

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

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

T. Non-Controlling Interests

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

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

U. Joint Arrangements

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

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

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

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

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

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

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

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

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

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

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

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

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations, and transmission capacity or constraints for the remaining life of the facilities. Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity, and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU, or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material. The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs, or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Corporation evaluates the market design, transmission constraints, and the contractual profile of each facility, as well as the Corporation's own commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization, 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 2015 to 2017 is found in Notes 6 and 17.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with 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 10 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 13. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

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

V. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 20. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VII. Useful Life of PP&E

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

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 27 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 20 with respect to other provisions.

3. Accounting Changes

A. Current Accounting Changes

Change in Estimates - Useful Lives
As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(H), the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 4(B) for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the life of Sundance Unit 2 to 2021 (see Note 4(B) for further details). As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017 decreased in total by approximately $4 million.

B. Future Accounting Changes

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

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property, and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Corporation on Jan. 1, 2018.

The Corporation has completed the review and accounting assessment of its revenue streams and underlying contracts with customers and the quantification of impacts. The majority of the Corporation's revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms, and from the sale of renewable energy certificates. IFRS 15 requires the application of a five-step model to determine when to recognize revenue, and at what amount. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Depending on whether certain criteria are met, revenue is recognized either over time, in a manner that depicts the entity's performance, or at a point in time, when control is transferred to the customer. The Corporation has not identified any significant differences in the timing or amount of recognition of revenue as a result of IFRS 15, with the exception of one difference, as discussed below.

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

The Corporation has chosen to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the consolidated financial statements as at and for the year ended Dec. 31, 2018, will not be restated. Instead, the Corporation will recognize the cumulative impact of the initial application of the standard in retained earnings as at Jan. 1, 2018. The cumulative impact of applying the significant financing component requirements to the identified contract results in a $12 million (net of tax impacts) charge to retained earnings.

II. IFRS 9 *Financial Instruments*

In July 2014, the IASB issued the final version of IFRS 9, which replaces IAS 39 *Financial Instruments: Recognition and* Measurement. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets, and a new hedge accounting model. IFRS 9 is required to be adopted retrospectively for annual periods beginning on or after Jan. 1, 2018 with early adoption permitted. IFRS 9 will be adopted by the Corporation on Jan. 1, 2018.

Under the new classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI. The classification and measurement depends on the contractual cash flow characteristics of the financial asset and the entity's business model for managing the financial asset. The classification requirements for financial liabilities are largely unchanged from IAS 39. Based on the assessment performed to date, the Corporation's classification and measurement of financial assets is not expected to be materially affected by the initial application of IFRS 9.

The new general hedge accounting model is intended to be simpler and more closely focused on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness. Based on its assessment to date, the Corporation is not expected to be materially affected by the new general hedge accounting model. However, where the Corporation uses foreign exchange forward contracts to hedge anticipated payments in foreign currency, and the hedged transaction results in a non-financial item, the reclassification of gains or losses on the hedges will be presented directly in the Statement of Changes in Equity as a reclassification from accumulated other comprehensive income.

The Corporation has completed its implementation plan, which included reviewing its various types of financial instruments to determine the impact of the new classification guidance, and assessing the historical credit loss data as well as considering reasonable and supportable forward-looking information that was available without undue cost or effort. There are no significant changes to classification and measurement identified. The Corporation is not expected to be materially impacted by the initial implementation of the expected credit loss impairment model. Ongoing disclosures are expected to be more extensive and will include information about the Corporation's risk management strategy, how the risk management activities may affect the amount, timing and uncertainty of future cash flows and the effect that hedge accounting has had on the statement of financial position, the statement of comprehensive income and the statement of changes in equity.

III. IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019, with early application permitted if IFRS 15 is also applied at the same time. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by the Corporation on Jan. 1, 2019.

We are in the process of completing an initial scoping assessment for IFRS 16 and have prepared a detailed project plan. We anticipate that most of the effort under the implementation plan will occur in mid-to-late 2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

C. Comparative Figures

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

4. Significant Events

A. Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C Power Purchase Arrangements ("Sundance PPAs") effective March 31, 2018.

The termination of the Sundance PPAs by the Balancing Pool was expected and the Corporation is working to ensure it receives the termination payment that it believes it is entitled to under the Sundance PPAs and applicable legislation. The expected impacts of the termination include approximately $215 million in compensation for the net book value of the assets as compared to the Balancing Pool's estimate of approximately $157 million. The Balancing Pool's estimate differs because it excludes certain mining assets that the Corporation believes should be included in the net book value calculation.

B. Transition to Clean Power in Alberta and Sundance Unit 1 Impairment Charge

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

On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. The strategy includes mothballing and retiring the following Sundance Units:

- retiring of Sundance Unit 1 effective Jan. 1, 2018;
- temporarily mothballing Sundance Unit 2 effective Jan. 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 3 effective April 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 4 effective April 1, 2019, for a period of up to two years; and
- temporarily mothballing Sundance Unit 5 effective April 1, 2018, for a period of up to one year.

As a result of the clarity provided by the draft coal-to-gas conversion rules proposed by the Government of Canada, the Corporation has determined to accelerate the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, a year earlier than originally planned. Although not yet finalized, the Government of Canada has proposed coal-to-gas conversion rules that would extend the life of the Corporation's gas conversion units by five to ten years past their federal end of coal life, depending on their CO_2 emissions profile. The proposed rules would see the life of TransAlta's entire coal-fired fleet extended by an aggregate of approximately 75 years. In addition to extending their operating lives, the benefits of converting units to gas generation include significantly lowering carbon intensities, emissions, and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility.

Temporarily mothballing the combination of Sundance Units throughout 2018 and 2019 ensures that two Sundance Units can operate at high-capacity utilizations with lower costs throughout the period to 2020 when additional power will be needed in the Alberta market. The mothballing of the units will also assist the Corporation in its preparations for converting Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, thereby extending the useful lives of these assets until the mid-2030s.

II. Gas Supply for Coal-to-Gas Conversions

On Dec. 6, 2017, the Corporation entered into a letter of intent with Tidewater Midstream and Infrastructure Ltd. ("Tidewater") to construct a 120-kilometre natural gas pipeline from Tidewater's Brazeau River complex to the Corporation's generating units at Sundance and Keephills facilities. The pipeline is expected to provide initial capacity of 130 million cubic feet of gas per day by 2020, and to have expansion capability to 340 million cubic feet of gas per day. The initial capacity will support fuel blending, using a fuel combination of coal and gas for generation, which will reduce the marginal cost as well as emissions. The Corporation will have the option to acquire up to a 50 per cent interest in the pipeline, which, if exercised, would reduce the costs associated with the tolling agreement.

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

III. Sundance Units 1 and 2
Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide the Corporation with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

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

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of $20 million due to the Corporation's decision to early retire Sundance Unit 1. See Note 6 for further details.

C. 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 subsidairy of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the power station has not reached commercial operation within a specified time period. FMG continues to be of the view that South Hedland Power Station has yet to achieve commercial operation.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies.

Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation will take all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA.

The South Hedland Power Station has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

D. Re-acquisition of Solomon Power Station

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action to recover all, or a significant portion of, this amount from FMG.

E. Kent Hills 3 Wind Project

During the second quarter of 2017, a subsidiary of TransAlta Renewables Inc. ("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 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 Kent Hills 2 and Kent Hills 3 wind projects.

This is an expansion of the Corporation's existing Kent Hills wind farm, increasing the total operating capacity of the Kent Hills wind farm to approximately 167 MW. As part of the regulatory process, the Corporation submitted an Environmental Impact Assessment to the Province of New Brunswick in the third quarter of 2017. The Corporation expects to begin the construction phase in the spring of 2018.

F. TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, KHWLP, closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds will be used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project (upon meeting certain completion tests and other specified conditions). The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers, Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP. Proceeds of $30 million were classified as restricted cash as at Dec. 31, 2017, and will be released from the construction reserve account upon commissioning.

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.

G. Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of Series E Preferred Shares into Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and the dividend rate remains fixed for the subsequent five-year period. See Note 24 for further details.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and the dividend remains fixed for the subsequent five-year period. See Note 13 for further details.

H. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an agreement with the Government of Alberta (the "Government") on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to certain terms and conditions. The Off-Coal Agreement's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include: maintaining prescribed spending on investment and investment-related activities in Alberta; maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels); and maintaining spending on programs and initiatives to support the communities surrounding the plants, the employees of the Corporation negatively impacted by the phase-out of coal generation, and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

The Corporation also entered into a Memorandum of Understanding ("MOU") with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas fired conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market to be developed for the Province of Alberta.

I. Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013 due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool are seeking to appeal or set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. TransAlta is opposing these steps and believes they are without merit. No provision has been recognized with respect to this.

J. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP, which holds the Corporation's interest in the Poplar Creek cogeneration facility, completed the private placement of a $202.5 million aggregate principal amount of senior secured floating rate bonds. The bonds, which mature on Dec. 31, 2030, are secured by a first ranking charge over the equity interests of the issuer of such bonds. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points.

K. 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 December 2018.

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in northeastern Ontario. Further details on the NUG Contract and its impact to these financial statements can be found in Note 8(B).

L. 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 proceeds of $61 million.

M. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables' indirect wholly owned subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

N. Investment in, and Acquisition by, TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility (the "Canadian Assets")

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Québec. The transaction was originally announced on Nov. 23, 2015.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. On Nov. 9, 2017, TransAlta Renewables repaid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. The convertible debenture was scheduled to mature on Dec. 31, 2020.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million through the issuance of a non-interest bearing loan payable to the Corporation.

The acquisition of the Canadian Assets was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the Canadian Assets' assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at Nov. 30, 2016, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $38 million in 2016.

O. Restructured Poplar Creek Contract and Acquisition of Wind Farms

On Sept. 1, 2015, the Corporation and Suncor Energy ("Suncor") restructured their arrangement for power generation services at Suncor's oil sands base site near Fort McMurray, Alberta.

The Corporation's Poplar Creek cogeneration facility, which has a maximum capacity of 376 MW, had been built and contracted to provide steam and electricity to Suncor until 2023 and is recorded in the gas segment. Under the terms of the new arrangement, Suncor acquired from TransAlta two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. The Corporation retained two gas turbines and heat recovery steam generators ("gas generators"), which are leased to Suncor. Suncor assumed full operational control of the cogeneration facility, including responsibility for all capital costs, and has the right to use the full 244 MW capacity of the Corporation's gas generators until Dec. 31, 2030. The Corporation provides Suncor with technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030. As the new contract was determined to constitute a finance lease, the full carrying amounts of the facility were derecognized.

As part of the transaction, the Corporation acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta. The Corporation's interest in the Wintering Hills facility was accounted for as a joint operation. At Dec. 31, 2016, the Wintering Hills facility was classified as assets held for sale (see Note 4(L)). The Corporation sold its interest in the Wintering Hills facility on March 1, 2017.

The following table outlines the impacts of the transaction on closing in 2015, including assets and liabilities disposed of and the fair value of assets acquired and liabilities assumed:

Assets	
Finance lease receivable[1]	372
Property, plant, and equipment	104
Intangibles	37
Net working capital	2
Total assets acquired	515
Liabilities	
Decomissioning and restoration provision	3
Net assets acquired	512
Consideration transferred	
Property, plant, and equipment	234
Net working capital	27
Decommissioning and restoration provision	(11)
Carrying amount of transferred net assets	250
Gain recognized	262

(1) Future payments under the finance lease include $57 million annually from 2016 to 2018, and $20 million annually from 2019 to 2030. Payments have been discounted at a rate of 2.68 per cent, based on comparative yield on borrowings of the counterparty with equivalent maturities at the time of closing.

The acquired wind farms' contribution to the Corporation's revenue and operating income from the date of acquisition until Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the wind farms would have contributed $8 million to revenues and reduced earnings before taxes by $2 million.

P. US Solar and Wind Acquisition

On Oct. 1, 2015, the Corporation acquired 100 per cent of the membership interests of Odin Wind Power LLC, owner of the 50 MW Lakeswind wind facility located in Minnesota, for cash consideration of $49 million and the assumption of certain tax equity obligations. The facility is contracted under long-term power purchase agreements until 2034.

On Sept. 1, 2015, the Corporation acquired 100 per cent of the membership interests of RC Solar LLC for cash consideration of $55 million. The assets acquired include 21 MW of fully contracted solar projects located in Massachusetts, which are contracted under long-term power purchase agreements ranging from 20 to 30 years, and are qualified under phase one of the Massachusetts Solar Renewable Energy Credit program.

At the 2015 acquisition dates, the fair values of the identifiable assets and liabilities of Odin Wind Power LLC and RC Solar LLC were as follows:

Assets	
Property, plant, and equipment	217
Inventory (SREC-I)	10
Net working capital	6
Total assets acquired	**233**
Liabilities	
Non-recourse debt	55
Tax equity liability	50
Deferred tax liabilities(1)	18
Decomissioning and restoration provision	4
Total liabilities assumed	**127**
Total consideration transferred	**106**

(1) The Corporation has recognized a corresponding deferred tax recovery in the Consolidated Statement of Earnings upon acquisition, representing deductible temporary differences now expected to be recovered.

The acquired assets' contribution to the Corporation's revenue and operating income from the date of acquisition until the end of Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the assets would have contributed $14 million to revenues and reduced earnings before taxes by $6 million.

Q. Sale of Economic Interest in Australian Assets to TransAlta Renewables

On May 7, 2015, the Corporation closed the acquisition by TransAlta Renewables of an economic interest based on the cash flows of the Corporation's Australian Assets. The Corporation's Australian Assets consisted of 575 MW of power generation from six operating assets and the South Hedland power project then under construction, as well as the 270-kilometre gas pipeline. TransAlta Renewables' investment consists of the acquisition of securities that, in aggregate, provide an economic interest based on cash flows of the Australian assets broadly equal to the underlying net distributable profits. The combined value of the transaction was $1.78 billion. The Corporation continues to own, manage, and operate the Australian assets.

With the closing of the transaction, the Corporation received net cash proceeds of $211 million as well as approximately $1,067 million through a combination of common shares and Class B shares of TransAlta Renewables. The Class B shares provided voting rights equivalent to the common shares, were non-dividend paying and converted into common shares on the commissioning of the South Hedland Power Station.

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to by TransAlta Renewables.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 common shares at a price of $12.65 per share. The offering closed in two parts on April 15 and 23, 2015. TransAlta Renewables received shareholder approval on May 7, 2015. TransAlta Renewables received approximately $226 million in gross proceeds, and in total, incurred $11 million in share issue costs, net of $3 million of income tax recovery. Proceeds to equity were further reduced by dividend-equivalent payments of $1 million.

R. Sale of TransAlta Renewables Shares to Alberta Investment Management Corporation

On Nov. 26, 2015, the Corporation completed the sale to Alberta Investment Management Corporation of 20,512,820 common shares of TransAlta Renewables for gross proceeds of $200 million (net proceeds of $193 million).

S. Restructuring Provision

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at its Canadian Coal power generation operations, resulting in the elimination of positions. On Sept. 29, 2015, the Corporation further reduced its overhead costs by eliminating positions primarily at its corporate head office in Calgary.

T. Changes in Internal Capitalization of US Entities

On Dec. 15, 2015, the Corporation partially redeemed its net investment in a wholly owned subsidiary. As a result, the Corporation reclassified from OCI pro rata cumulative translation gains of $10 million, offset by related pro rata cumulative after-tax losses of $6 million from the net investment hedge.

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2017		2016		2015	
	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	**775**	**—**	755	—	775	—
Coal inventory writedown (recovery)	**—**	**—**	(4)	—	22	—
Purchased power	**162**	**—**	143	—	147	—
Mine depreciation	**73**	**—**	63	—	59	—
Salaries and benefits	**6**	**248**	6	249	5	250
Other operating expenses	**—**	**269**	—	240	—	242
Total	**1,016**	**517**	963	489	1,008	492

6. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. Alberta Merchant CGU

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

I. 2017

Sundance Unit 1

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

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

II. 2016

On Nov. 24, 2016, the Corporation reached an Off-Coal Agreement with the Government to receive annual cash payments of approximately $37.4 million, net to the Corporation (see Note 4(H) for further details) in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, the Corporation entered into an MOU on Nov. 24, 2016, with the purpose of collaborating and co-operating to advance objectives of the Alberta CLP. Specifically, the parties undertook to collaborate on, among other things:

- a move toward a capacity market, commencing in 2021, compared to the current energy-only market. Under a capacity market, generators are compensated for their available capacity;
- development of a policy and to facilitate the economic conversion of some coal-fired generation to natural-gas-fired generation in Alberta, including securing regulatory co-operation from the federal government; and
- policy development to address the value of carbon reductions in the generation of electricity from existing wind and hydro production, the development of effective supporting mechanisms to ensure that existing renewable generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Government and the Corporation and does not impose any obligations on, or constrain the discretion and authority of, the Government. The announcement of the intention to move to a capacity market is expected to impact the Alberta market mechanisms. The introduction of a capacity market to replace Alberta's current market structure could impact the Corporation's determination of the Alberta Merchant CGU; however, there is not currently sufficient information from the Government or the Alberta Electric System Operator, which is overseeing the development of the capacity market, to determine if a change is required. The Corporation has not modified its previous conclusions on the determination of the Alberta Merchant CGU.

Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million (see Note 4(E)). In connection with this sale, the Wintering Hills assets were accounted for as held for sale at Dec. 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal in 2016.

III. 2015

In 2015, the Government announced its CLP, which broadly called for the phase-out of coal-generated electricity by 2030, and proposed the imposition of additional compliance obligations for GHG emissions in the province. In 2016, the Government refined its approach to GHG by announcing the adoption of a levy on carbon emissions in excess of defined limits, amounting to $20 per tonne in 2017 and $30 per tonne in 2018. At the federal level, the Canadian government announced its intention to implement a national price on GHG emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022.

B. US Coal

The Corporation considered possible indicators of impairment at US Coal in 2017, 2016, and 2015, as discussed in more detail below.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded in 2017, 2016 or 2015. Any adverse change in assumptions, in isolation, would have resulted in an impairment charge being recorded. The Corporation continues to manage risks associated with the CGU by optimizing of its operating activities and capital plan.

The valuations are 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 extended to the assumed decommissioning of the plant, after its projected cessation of operation in its current form in 2025.

I. 2017

During 2017, the Corporation renegotiated rail transportation and coal supply agreements. Accordingly, the Corporation completed an estimate of the impact for the coal cost changes combined with updated power prices to determine whether the US Coal CGU had an indicator of impairment. The Corporation concluded that there is no indicator of impairment. The Corporation utilized the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$21.50 to US$34.81 per MWh
On-highway diesel fuel on coal shipments	US$2.08 to US$2.29 per gallon
Discount rates	7.9 to 9.0 per cent

II. 2016

During 2016, the Corporation considered possible impairment at the US Coal CGU and found that the fair value less costs to sell approximated the then current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$22.00 to US$46.00 per MWh
On-highway diesel fuel on coal shipments	US$1.69 to US$2.09 per gallon
Discount rates	5.4 to 5.7 per cent

III. 2015

During 2015, the Corporation considered possible impairment at the US Coal CGU and found that the fair value less costs to sell approximated the then current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$24.00 to US$50.00 per MWh
On-highway diesel fuel on coal shipments	US$2.44 to US$2.90 per gallon
Discount rates	5.2 to 6.2 per cent

Impairment reversals of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

7. Finance Lease Receivables

A. Re-acquisition of Solomon Power Station

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe, a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017 and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not be held back and the Corporation is taking action to recover all, or a significant portion of, this amount from FMG.

B. Amounts Receivable

Amounts receivable under the Corporation's finance leases, associated with the Fort Saskatchewan cogeneration facility and the Poplar Creek cogeneration facility, and in 2016 the Solomon Power Station, are as follows:

As at Dec. 31	**2017**		2016	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**68**	**66**	124	119
Second to fifth years inclusive	**110**	**82**	376	291
More than five years	**140**	**126**	637	311
	318	**274**	1,137	721
Less: unearned finance lease income	**44**	**—**	592	—
Add: unguaranteed residual value	**—**	**—**	233	57
Total finance lease receivables	**274**	**274**	778	778

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables *(Note 12)*	**59**	59
Long-term portion of finance lease receivables	**215**	719
	274	778

8. Net Other Operating (Income) Losses

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

Year ended Dec. 31	2017	2016	2015
Alberta Off-Coal Agreement	(40)	–	–
Mississauga cogeneration facility NUG Contract	(9)	(191)	–
Market Surveillance Administrator Agreement settlement	–	–	56
Insurance recoveries	–	(3)	(31)
Net other operating (income) losses	**(49)**	(194)	25

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into the OCA with the Government on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2020.

B. Mississauga Cogeneration Facility Contract

2016

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the IESO for its Mississauga cogeneration facility. The contract is effective on Jan. 1, 2017. The Corporation has agreed to terminate the existing contract with the Ontario Electricity Financial Corporation early, which would have otherwise terminated in December 2018.

As a result of the NUG Contract, the Corporation recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling approximately $16 million. The Corporation also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. The Corporation released and recognized in earnings unrealized pre-tax net losses of $14 million from AOCI due to cash flow hedges de-designated for accounting purposes. The cash flow hedges were in respect of future gas purchases denominated in US dollars and expected to occur between 2017 and 2018. In the fourth quarter of 2016, the forecasted gas consumption was no longer expected to occur, which resulted in the cumulative loss on the hedging instrument being released from AOCI and recognized in earnings.

2017

During the fourth quarter of 2017, the Corporation renegotiated the facility's land lease agreement at a lower cost than previously estimated in 2016, and accordingly, recognized a gain of $9 million.

C. Settlement with the Market Surveillance Administrator

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the Alberta Utilities Commission (the "AUC") alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. The Corporation denied the MSA's allegations. An oral hearing took place before the AUC in December 2014. A written argument was filed in February 2015. In May 2015, further submissions were filed on a recent Supreme Court of Canada decision relevant to expert evidence. On July 27, 2015, the AUC issued a decision finding, among other things, that i) the Corporation's actions in relation to four outage events at its coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated PPA buyers and manipulated market prices away from a competitive market outcome and ii) the Corporation breached applicable legislation by allowing one of its employees to trade while in possession of non-public outage records. The AUC also found that the MSA did not prove, on the balance of probabilities, that the Corporation breached applicable legislation on the basis that its compliance policies, practices, and oversight thereof, were inadequate and deficient.

This AUC decision marked the end of the first phase of the proceedings. TransAlta filed for leave to appeal the AUC decision with the Alberta Court of Appeal in August 2015. The second phase of the AUC proceedings was to consider what penalty the AUC might impose against the Corporation. On Sept. 30, 2015, TransAlta and the MSA reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which is in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the consent order, the Corporation paid a total amount of $56 million that includes approximately $27 million as a repayment of economic benefit, $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million was paid in the fourth quarter of 2015, and the $25 million administrative penalty was paid in November 2016. As a result of the approval, the Corporation discontinued the appeal of the AUC's decision.

D. Insurance Recoveries

There were no insurance recoveries in 2017.

During 2016, the Corporation received $3 million in insurance recoveries (2015 - $31 million), of which $2 million (2015 - $6 million) related to business interruption insurance claims and $1 million related to claims for replacement and refurbishment of equipment for certain wind facilities (2015 - $7 million for Canadian Coal facilities).

In 2015 the Corporation received $18 million of insurance recoveries related to claims for the replacement and refurbishment of certain hydro facilities as a result of the flooding in Southern Alberta in 2013. Additionally, in 2015, $12 million of insurance proceeds were received related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in 2013 and were accounted for as a reduction to period operations, maintenance, and administration costs.

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2017**	2016	2015
Interest on debt	**218**	218	218
Interest income	**(7)**	(2)	(2)
Capitalized interest *(Note 16)*	**(9)**	(16)	(9)
Loss on redemption of bonds *(Note 4(F))*	**6**	1	—
Interest on finance lease obligations	**3**	3	4
Credit facility fees, bank charges, and other interest	**18**	19	10
Keephills 1 outage interest accruals (reversals) *(Note 4)*	**—**	(10)	9
Other	**(3)**	(4)	—
Accretion of provisions *(Note 20)*	**21**	20	21
Net interest expense	**247**	229	251

10. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2017	2016	2015
Earnings before income taxes	**(54)**	314	221
Net earnings attributable to non-controlling interests not subject to tax	**(35)**	(109)	(34)
Adjusted earnings before income taxes	**(89)**	205	187
Statutory Canadian federal and provincial income tax rate (%)	**26.8**	26.7	25.9
Expected income tax expense (recovery)	**(24)**	55	48
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(11)**	(16)	(16)
Deferred income tax expense related to temporary difference on investment in subsidiary	**—**	11	95
MSA settlement	**—**	—	14
Reversal of writedown of deferred income tax assets	**(15)**	(10)	(56)
Statutory and other rate differences	**110**	1	20
Other	**4**	(3)	—
Income tax expense	**64**	38	105
Effective tax rate (%)	**72**	19	56

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2017	2016	2015
Current income tax expense[1]	**79**	23	24
Adjustments in respect of current income tax of previous years	**—**	—	(5)
Adjustments in respect of deferred income tax of previous years	**—**	(3)	5
Deferred income tax expense related to the origination and reversal of temporary differences	**(110)**	16	22
Deferred income tax expense related to temporary difference on investment in subsidiary[2]	**—**	11	95
Deferred income tax expense resulting from changes in tax rates or laws[3]	**110**	1	20
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets[4]	**(15)**	(10)	(56)
Income tax expense	**64**	38	105

Year ended Dec. 31	2017	2016	2015
Current income tax expense	**79**	23	19
Deferred income tax expense (recovery)	**(15)**	15	86
Income tax expense	**64**	38	105

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon Power Station on Nov. 1, 2017.
(2) In 2016, reorganizations of certain TransAlta subsidiaries were completed in connection with the New Richmond project financing and the disposition of the Canadian Assets to TransAlta Renewables. The reorganizations resulted in the recognition of deferred tax liabilities of $3 million and $8 million, respectively. In 2015, in order to give effect to the sale of an economic interest in the Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a $95 million deferred tax liability on TransAlta's investment in a subsidiary. For both 2015 and 2016, the deferred tax liabilities had not been recognized previously, as prior to the reorganizations, the taxable temporary differences were not expected to reverse in the foreseeable future.
(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act*, which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income. 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016. 2015 relates to the impact of an increase in the Alberta corporate income tax rate from 10 per cent to 12 per cent, enacted June 18, 2015.*
(4) During the year ended Dec. 31, 2017, the Corporation reversed a previous writedown of deferred income tax assets of $15 million (2016 - $10 million writedown reversal, 2015 - $56 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2037. Recognized OCI during the years ended Dec. 31, 2017 and 2016, 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	2017	2016	2015
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(108)**	51	89
Net impact related to net investment hedges	**(7)**	16	8
Net actuarial gains (losses)	**(4)**	4	—
Share issuance costs	**—**	—	(4)
Loss on sale of investment in subsidiary	**—**	—	(8)
Income tax expense reported in equity	**(119)**	71	85

C. Consolidated Statements of Financial Position

Significant components of the Corporation's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2017	2016
Net operating loss carryforwards	**541**	768
Future decommissioning and restoration costs	**117**	103
Property, plant, and equipment	**(1,009)**	(1,114)
Risk management assets and liabilities, net	**(160)**	(282)
Employee future benefits and compensation plans	**74**	70
Interest deductible in future periods	**50**	90
Foreign exchange differences on US-denominated debt	**42**	69
Deferred coal revenues	**16**	17
Other deductible temporary differences	**22**	3
Net deferred income tax liability, before writedown of deferred income tax assets	**(307)**	(276)
Writedown of deferred income tax assets	**(218)**	(383)
Net deferred income tax liability, after writedown of deferred income tax assets	**(525)**	(659)

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2017	2016
Deferred income tax assets[1]	**24**	53
Deferred income tax liabilities	**(549)**	(712)
Net deferred income tax liability	**(525)**	(659)

(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, 2017, the Corporation had recognized a net liability of $4 million (2016 - $7 million) related to uncertain tax positions. The decrease was the result of settlements with taxation authorities.

11. 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, 2017
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	36% - 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 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 150 MW Kent Hills wind farm located in New Brunswick.

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables.

As a result of the conversion of Class B shares and the transactions described in Note 4, the Corporation's share of ownership and equity participation in TransAlta Renewables has fluctuated since its formation as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 and thereafter	64.0	64.0

Year ended Dec. 31	**2017**	2016	2015
Revenues	**459**	259	236
Net earnings	**13**	1	198
Total comprehensive income	**(24)**	40	204
Amounts attributable to the non-controlling interests:			
Net earnings	**11**	2	63
Total comprehensive income	**—**	18	65
Distributions paid to non-controlling interests	**85**	83	43

As at Dec. 31	2017	2016
Current assets	**145**	109
Long-term assets	**3,483**	3,732
Current liabilities	**(356)**	(537)
Long-term liabilities	**(1,075)**	(1,237)
Total equity	**(2,197)**	(2,067)
Equity attributable to non-controlling interests	**(812)**	(851)
Non-controlling interests' share (per cent)	**36.0**	40.2

B. TA Cogen

Year ended Dec. 31	2017	2016	2015
Results of operations			
Revenues	**175**	274	288
Net earnings	**61**	211	61
Total comprehensive income	**61**	258	77
Amounts attributable to the non-controlling interest:			
Net earnings	**31**	105	31
Total comprehensive income	**31**	128	38
Distributions paid to Canadian Power Holdings Inc.	**87**	68	56

As at Dec. 31	2017	2016
Current assets	**193**	171
Long-term assets	**404**	538
Current liabilities	**(73)**	(65)
Long-term liabilities	**(26)**	(35)
Total equity	**(498)**	(609)
Equity attributable to Canadian Power Holdings Inc.	**(247)**	(301)
Non-controlling interest share (per cent)	**49.99**	49.99

12. Trade and Other Receivables

As at Dec. 31	2017	2016
Trade accounts receivable	**693**	446
Mississauga recontracting receivable	**108**	112
Net trade receivables	**801**	558
Collateral paid *(Note 14)*	**67**	77
Current portion of finance lease receivables *(Note 7)*	**59**	59
Current portion of loan receivable *(Note 19)*	**5**	–
Income taxes receivables	**1**	9
Trade and other receivables	**933**	703

13. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost (see Note 2 (C)). The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2017	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents[1]	–	–	314	–	314
Restricted cash	–	–	30	–	30
Trade and other receivables	–	–	933	–	933
Long-term portion of finance lease receivables	–	–	215	–	215
Risk management assets					
Current	82	137	–	–	219
Long-term	638	46	–	–	684
Other assets	–	–	33	–	33
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	595	595
Dividends payable	–	–	–	34	34
Risk management liabilities					
Current	8	93	–	–	101
Long-term	2	38	–	–	40
Credit facilities, long-term debt and finance lease obligations[2]	–	–	–	3,707	3,707

(1) Includes cash equivalents of nil.
(2) Includes current portion.

Carrying value as at Dec. 31, 2016

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents[1]	—	—	305	—	305
Trade and other receivables	—	—	703	—	703
Long-term portion of finance lease receivables	—	—	719	—	719
Other assets	—	—	116	—	116
Risk management assets					
Current	192	57	—	—	249
Long-term	749	36	—	—	785
Financial liabilities					
Accounts payable and accrued liabilities	—	—	—	413	413
Dividends payable	—	—	—	54	54
Risk management liabilities					
Current	1	65	—	—	66
Long-term	4	44	—	—	48
Credit facilities, long-term debt and finance lease obligations[2]	—	—	—	4,361	4,361

(1) Includes cash equivalents of $103 million.
(2) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level I, II, and III Fair Value Measurements

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

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

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses.

Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at Dec. 31	2017		2016	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**853**	**+130 -130**	907	+76 -69
Long-term power sale - Alberta	**(1)**	**+2 -2**	(3)	+5 -5
Unit contingent power purchases	**44**	**+7 -9**	13	+2 -4
Structured products - Eastern US	**17**	**+8 -7**	24	+8 -8
Others	**5**	**+9 -9**	6	+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 2019, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by averaging external fundamental-based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2017 are US$25 - US$34 (Dec. 31, 2016 - US$27 - US$36). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2016 - US$5) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2016 to Dec. 31, 2017, the base fair value and the sensitivity values have decreased by approximately $50 million and $8 million, respectively.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as held for trading.

For periods beyond 2022, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high, and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2017, are $63 - $67 (Dec. 31, 2016 - $68 - $93). The sensitivity analysis has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. Unit Contingent Power Purchases

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as held for trading.

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, 2017, are nil (Dec. 31, 2016 - nil) and 2.20 per cent to 2.76 per cent (Dec. 31, 2016 – 2.15 per cent to 3.62 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.1 per cent to 1.94 per cent (Dec. 31, 2016 - 0.75 per cent) and a change in volumetric discount rates of approximately 7.77 per cent to 10.46 per cent (Dec. 31, 2016 - 15.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations, or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2017, are 75 per cent to 159 per cent and 71 per cent to 88 per cent (Dec. 31, 2016 – 66 per cent to 128 per cent and 65 per cent to 88 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 7 per cent (Dec. 31, 2016 - 5 per cent) and a change in non-standard shape factors of approximately 6 per cent (Dec. 31, 2016 - 9 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2017, are 18 per cent to 54 per cent and 70 per cent (Dec. 31, 2016 – 20 per cent to 54 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 27 per cent to 32 per cent and 10 per cent, respectively (2016 - 10 per cent).

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, 2017, are as follows: Level I - $1 million net liability (Dec. 31, 2016 - nil), Level II - $42 million net liability (Dec. 31, 2016 - $14 million net liability), Level III - $771 million net asset (Dec. 31, 2016 - $758 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2017 are primarily attributable to the changes in value of the long-term power sale contract (Level III hedge) as discussed in the preceding section (B)(I)(c)(i) of this note.

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, 2017 and 2016, respectively:

	Year ended Dec. 31, 2017			Year ended Dec. 31, 2016		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**726**	**32**	**758**	640	(98)	542
Changes attributable to:						
Market price changes on existing contracts	**100**	**(2)**	**98**	163	13	176
Market price changes on new contracts	**—**	**33**	**33**	—	29	29
Contracts settled	**(57)**	**(10)**	**(67)**	(50)	88	38
Change in foreign exchange rates	**(50)**	**(2)**	**(52)**	(27)	—	(27)
Transfers into Level III	**—**	**1**	**1**	—	—	—
Net risk management assets at end of period	**719**	**52**	**771**	726	32	758
Additional Level III information:						
Gains recognized in other comprehensive income	**50**	**—**	**50**	136	—	136
Total gains included in earnings before income taxes	**57**	**29**	**86**	50	42	92
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**19**	**19**	—	130	130

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 $34 million as at Dec. 31, 2017 (Dec. 31, 2016 - $176 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2017, are primarily attributable to the settlement of contracts.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value**
Long-term debt[(1)] - Dec. 31, 2017	**—**	**3,708**	**—**	**3,708**	**3,638**
Long-term debt[(1)] - Dec. 31, 2016	—	4,271	—	4,271	4,221

(1) Includes current portion. 2016 excludes $67 million of debt measured and carried at fair value.

The fair values of the Corporation's debentures and senior notes are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 19) and the finance lease receivables (see Note 7) approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	**2017**	2016	2015
Unamortized net gain at beginning of year	**148**	202	188
New inception gains	**12**	10	28
Change in foreign exchange rates	**(7)**	(4)	28
Amortization recorded in net earnings during the year	**(48)**	(60)	(42)
Unamortized net gain at end of year	**105**	148	202

14. Risk Management Activities

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2017

	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	**74**	**–**	**7**	**81**
Long-term	**636**	**–**	**11**	**647**
Net commodity risk management assets	**710**	**–**	**18**	**728**
Other				
Current	**–**	**–**	**37**	**37**
Long-term	**–**	**–**	**(3)**	**(3)**
Net other risk management assets (liabilities)	**–**	**–**	**34**	**34**
Total net risk management assets (liabilities)	**710**	**–**	**52**	**762**

As at Dec. 31, 2016

	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	86	–	(16)	70
Long-term	683	–	(9)	674
Net commodity risk management assets	769	–	(25)	744
Other				
Current	105	–	8	113
Long-term	59	3	1	63
Net other risk management assets (liabilities)	164	3	9	176
Total net risk management assets (liabilities)	933	3	(16)	920

Additional information on derivative instruments has been presented on a net basis below.

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	2017				2016			
	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	**281**	**637**	**(159)**	**(38)**	315	744	(113)	(53)
Gross amounts set-off	**(43)**	**—**	**43**	**—**	(24)	(3)	24	3
Net amounts as presented in the Consolidated Statements of Financial Position	**238**	**637**	**(116)**	**(38)**	291	741	(89)	(50)

II. Hedges

a. Net Investment Hedges

The Corporation's hedges of its net investment in foreign operations in 2017 were comprised of US-dollar-denominated long-term debt with a face value of US$480 million (2016 - US$630 million). During 2016, the Corporation de-designated its foreign currency forward contracts from its net investment hedges. The cumulative unrealized losses on these contracts will be deferred in AOCI until the disposal of the related foreign operation.

b. Cash Flow Hedges

i. Commodity Risk Management

The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	2017		2016	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**1,997**	**44**	4,916	—

During 2017, additional unrealized pre-tax gains of $2 million (2016 - nil, 2015 - $3 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. The cash flow hedges were in respect of future power production expected to occur between 2012 and 2017. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using then current forward prices that changed between then and the time the contracts settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts would not change.

As at Dec. 31, 2017, cumulative gains of $1 million (2016 - $4 million) related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

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.

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. As at March 31, 2017, cumulative gains on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

As at Dec. 31		**2017**		2016			
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							
CAD9	**USD7**	**—**	**2018**	—	—	—	—
CAD14	**EUR9**	**—**	**2018**	—	—	—	—
AUD1	**JPY119**	**—**	**2018**	AUD8	JPY710	1	2017
Foreign Exchange Forward Contracts - foreign-denominated debt							
—	**—**	**—**	**—**	CAD26	USD20	—	2018
Cross-Currency Swaps - foreign-denominated debt							
—	**—**	**—**	**—**	CAD434	USD400	104	2017
—	**—**	**—**	**—**	CAD306	USD270	59	2018

iii. Effect of Cash Flow Hedges

The following tables summarize the pre-tax amounts recognized in and reclassified out of OCI related to cash flow hedges:

		Year ended Dec. 31, 2017			
		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**163**	Revenue	**(172)**	Revenue	**—**
		Fuel and purchased power	**—**	Fuel and purchased power	**—**
Foreign exchange forwards on commodity contracts	**—**	Revenue	**—**	Revenue	**—**
Foreign exchange forwards on project hedges	**(1)**	Property, plant, and equipment	**—**	Foreign exchange (gain) loss	**—**
Foreign exchange forwards on US debt	**—**	Foreign exchange (gain) loss	**3**	Foreign exchange (gain) loss	**—**
Cross-currency swaps	**(26)**	Foreign exchange (gain) loss	**24**	Foreign exchange (gain) loss	**—**
Forward starting interest rate swaps	**—**	Interest expense	**7**	Interest expense	**—**
OCI impact	**136**	**OCI impact**	**(138)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $85 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, 2016					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	304	Revenue	(169)	Revenue	—
		Fuel and purchased power	44	Fuel and purchased power	31
Foreign exchange forwards on commodity contracts	(5)	Revenue	(16)	Revenue	(15)
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	(2)	Foreign exchange (gain) loss	53	Foreign exchange (gain) loss	—
Cross-currency swaps	(25)	Foreign exchange (gain) loss	(23)	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	271	OCI impact	(105)	Net earnings impact	16

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminates the generation effective Jan. 1, 2017. Accordingly, 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 8(B) for further details.

Year ended Dec. 31, 2015					
		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		Revenue	(110)	Revenue	5
	308	Fuel and purchased power	41	Fuel and purchased power	—
Foreign exchange forwards on commodity contracts	32	Revenue	(12)	Revenue	—
Foreign exchange forwards on project hedges	4	Property, plant, and equipment	(1)	Foreign exchange (gain) loss	—
Foreign exchange forwards on U.S. debt	10	Foreign exchange (gain) loss	(12)	Foreign exchange (gain) loss	—
Cross-currency swaps	163	Foreign exchange (gain) loss	(163)	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	517	OCI impact	(250)	Net earnings impact	5

During 2015, total unrealized pre-tax gains of $6 million were released from AOCI and recognized in earnings due to hedge de-designations for accounting purposes.

c. Fair Value Hedges

i. Interest Rate Risk Management

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain fair value hedges on US$50 million of debt. As at March 31, 2017, cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt's maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively. See section II(b)(ii) of this note for information on these non-hedge derivatives.

During 2016, the Corporation had converted a portion of its fixed interest rate debt with a rate of 6.65 per cent to a floating interest rate based on the US LIBOR rate using interest rate swaps as outlined below:

As at Dec. 31	2017			2016	
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
—	—	—	**USD50**	3	2018

Including interest rate swaps outlined in section II(b)(ii) of this note, and the above swap in 2016, 6 per cent of the Corporation's debt as at Dec. 31, 2017 is subject to floating interest rates (2016 - 6 per cent).

III. Non-Hedges

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 held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Commodity Risk Management

As at Dec. 31	2017		2016	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**14,688**	**7,348**	19,362	19,060
Natural gas *(GJ)*	**74,195**	**103,805**	146,113	173,187
Transmission *(MWh)*	**1**	**3,455**	—	3,429
Emissions *(tonnes)*	**516**	**717**	1,370	1,370
Heating oil *(gallons)*	**—**	**—**	—	294

b. Other Non-Hedge Derivatives

i. Foreign Currency

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

As at Dec. 31		**2017**				2016	
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							
AUD170	**CAD157**	**(9)**	**2018-2021**	**USD152**	**CAD216**	12	2017-2020
USD73	**CAD104**	**11**	**2018-2021**	**AUD232**	**CAD219**	(3)	2017-2020
Foreign Exchange Forward Contracts - foreign-denominated debt							
CAD294	**USD230**	**(4)**	**2018**	—	—	—	—
Cross Currency Swaps - foreign-denominated debt							
CAD306	**USD270**	**35**	**2018**	—	—	—	—

ii. Interest Rate

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (2016 - 6.65 per cent) to a floating interest rate based on the US LIBOR rate using interest rate. The Corporation has converted a portion of its floating rate debt to a fixed rate of 4.7 per cent.

As at Dec. 31		**2017**			2016	
	Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
Fixed rate debt	**USD50**	**1**	**2018**	—	—	—
Floating rate debt	**USD22**	**—**	**2018-24**	—	—	—

c. 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. Effect of Non-Hedges

For the year ended Dec. 31, 2017, the Corporation recognized a net unrealized gain of $45 million (2016 - loss of $63 million, 2015 - loss of $51 million) related to commodity derivatives.

For the year ended Dec. 31, 2017, a gain of $28 million (2016 - gain of $9 million, 2015 - loss of $1 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized losses of $2 million (2016 - gains of $4 million, 2015 - loss of $11 million) and net realized gains of $30 million (2016 - gains of $5 million, 2015 - gains of $10 million).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

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

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2017, associated with the Corporation's proprietary trading activities was $5 million (2016 - $2 million, 2015 - $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, 2017, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $16 million (2016 - $19 million, 2015 - $24 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. 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, 2017, associated with these transactions was $5 million (2016 - $7 million, 2015 - $1 million).

b. Interest Rate Risk
Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 15 basis point (2016 - 15 basis point, 2015 - 15 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2017**		2016		2015	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
Basis point change	**—**	**—**	—	—	**1**	—

(1)This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.

c. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar, the Japanese yen, the euro and the Australian dollar ("AUD"), as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

As part of the Australian Assets transaction described in Note 4(Q), 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 2016, a $5 million loss was recognized. 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. In 2017, a $6 million foreign exchange loss was recognized.

The Corporation also uses foreign currency contracts to hedge its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2016 and 2015 - 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	2017		2016		2015	
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	**(5)**	**—**	(5)	—	2	5
AUD	**(7)**	**—**	(7)	—	(3)	—
Total	**(12)**	**—**	(12)	—	(1)	5

(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, 2017:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1)	87	13	**100**	**933**
Long-term finance lease receivables	96	4	**100**	**215**
Risk management assets(1)	99	1	**100**	**903**
Loan receivable(2)	—	100	**100**	**33**
Total				**2,084**

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

The Corporation's maximum exposure to credit risk at Dec. 31, 2017, 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, 2017, was $40 million (2016 - $14 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. As at Dec. 31, 2017, TransAlta maintains investment grade ratings from three credit rating agencies. TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

Counterparties enter into certain commodity agreements, such as electricity and natural gas purchase and sale contracts, for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these agreements may contain credit-contingent features (such as downgrades in creditworthiness), which if triggered may result in the Corporation having to post collateral to its counterparties.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; and reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management, and the Board.

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

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Accounts payable and accrued liabilities	595	—	—	—	—	—	595
Long-term debt(1)	730	469	472	100	581	1,312	3,664
Commodity risk management assets	(81)	(94)	(88)	(102)	(103)	(260)	(728)
Other risk management (assets) liabilities	(37)	1	1	1	—	—	(34)
Finance lease obligations	18	15	12	6	4	14	69
Interest on long-term debt and finance lease obligations(2)	177	153	125	102	95	692	1,344
Dividends payable	34	—	—	—	—	—	34
Total	**1,436**	**544**	**522**	**107**	**577**	**1,758**	**4,944**

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

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2017, the Corporation provided $67 million (2016 - $77 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 statement of financial position.

II. Financial Assets Held as Collateral

At Dec. 31, 2017, the Corporation held $21 million (2016 - $21 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2017, the Corporation had posted collateral of $131 million (Dec. 31, 2016 - $116 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 $96 million (Dec. 31, 2016 - $49 million) of collateral to its counterparties.

15. 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 Energy Marketing, 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	**2017**	2016
Parts and materials	**118**	110
Coal	**58**	65
Deferred stripping costs	**11**	12
Natural gas	**9**	17
Purchased emission credits	**23**	9
Total	**219**	213

The change in inventory is as follows:

Balance, Dec 31, 2015	219
Net use	(12)
Writedowns	(9)
Reversal of writedowns	13
Change in foreign exchange rates	2
Balance, Dec 31, 2016	213
Net addition	**11**
Change in foreign exchange rates	**(5)**
Balance, Dec 31, 2017	**219**

No inventory is pledged as security for liabilities.

16. 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, 2015	95	6,091	1,484	3,265	1,208	351	360	12,854
Additions	2	—	—	1	—	353	2	358
Additions - finance lease	—	—	—	—	7	—	—	7
Disposals	(1)	—	(3)	(1)	(1)	—	(3)	(9)
Impairment charge - Wintering Hills *(Note 4)*	—	—	—	(28)	—	—	—	(28)
Reclassification to held for sale *(Note 4)*	—	—	—	(67)	—	—	—	(67)
Other *(Note 6)*	—	—	—	—	—	—	(1)	(1)
Revisions and additions to decommissioning and restoration costs	—	14	12	4	36	—	5	71
Retirement of assets	—	(96)	(3)	(14)	(6)	—	(3)	(122)
Change in foreign exchange rates	(1)	(38)	(16)	(10)	(3)	(13)	(4)	(85)
Transfers[2]	—	(95)	51	62	24	(284)	37	(205)
As at Dec 31, 2016	95	5,876	1,525	3,212	1,265	407	393	12,773
Additions	**—**	**—**	**—**	**—**	**—**	**334**	**4**	**338**
Additions - finance lease	**—**	**—**	**—**	**—**	**14**	**—**	**—**	**14**
Disposals	**—**	**—**	**(16)**	**(1)**	**(1)**	**—**	**(1)**	**(19)**
Impairment charge - Sundance Unit 1 *(Note 6)*	**—**	**(20)**	**—**	**—**	**—**	**—**	**—**	**(20)**
Revisions and additions to decommissioning and restoration costs	**—**	**82**	**12**	**15**	**42**	**—**	**—**	**151**
Retirement of assets	**—**	**(84)**	**(3)**	**(4)**	**(22)**	**—**	**(6)**	**(119)**
Change in foreign exchange rates	**(1)**	**(87)**	**3**	**(23)**	**(7)**	**(2)**	**(2)**	**(119)**
Transfers[3]	**1**	**121**	**461**	**29**	**24**	**(644)**	**(18)**	**(26)**
As at Dec 31, 2017	**95**	**5,888**	**1,982**	**3,228**	**1,315**	**95**	**370**	**12,973**
Accumulated depreciation								
As at Dec 31, 2015	—	3,280	873	810	604	—	114	5,681
Depreciation	—	284	118	127	59	—	19	607
Retirement of assets	—	(85)	(4)	(7)	(2)	—	(3)	(101)
Disposals	—	—	(1)	—	(1)	—	—	(2)
Reclassification to held for sale *(Note 4)*	—	—	—	(6)	—	—	—	(6)
Change in foreign exchange rates	—	(28)	(10)	—	(1)	—	—	(39)
Transfers	—	(239)	51	(2)	—	—	(1)	(191)
As at Dec 31, 2016	—	3,212	1,027	922	659	—	129	5,949
Depreciation	—	351	67	123	76	—	18	635
Retirement of assets	—	(62)	(2)	(3)	(18)	—	(5)	(90)
Disposals	—	—	(11)	(1)	—	—	—	(12)
Change in foreign exchange rates	—	(67)	(1)	(4)	(4)	—	—	(76)
Transfers[2]	—	(3)	(8)	—	—	—	—	(11)
As at Dec 31, 2017	**—**	**3,431**	**1,072**	**1,037**	**713**	**—**	**142**	**6,395**
Carrying amount								
As at Dec 31, 2015	95	2,811	611	2,455	604	351	246	7,173
As at Dec 31, 2016	95	2,664	498	2,290	606	407	264	6,824
As at Dec 31, 2017	**95**	**2,457**	**910**	**2,191**	**602**	**95**	**228**	**6,578**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive, or planned maintenance.
(2) Net transfers of $14 million relate to the transfer of gas equipment to finance lease receivables.
(3) During the second quarter of 2017, the Corporation reclassified approximately $13 million of capital spares and other assets to inventory.

The Corporation capitalized $9 million of interest to PP&E in 2017 (2016 - $16 million) at a weighted average rate of 5.87 per cent (2016 – 5.93 per cent).

Finance lease additions in 2017 and 2016 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2017 was $65 million (2016 - $76 million).

17. 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	2017	2016
Hydro	**259**	259
Wind and Solar	**174**	175
Energy Marketing	**30**	30
Total goodwill	**463**	464

For the purposes of the 2017 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. In 2017, the Corporation relied on the recoverable amounts determined in 2016 for the Hydro and Energy Marketing segments in performing the 2017 annual goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2017 models ranged between $22 to $218 per MWh during the forecast period (2016 - $32 to $301 per MWh). Discount rates used for the goodwill impairment calculation in 2017 ranged from 5.5 per cent to 6.0 per cent (2016 – 5.5 per cent to 6.0 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

18. 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, 2015	178	256	223	15	672
Additions	—	—	—	21	21
Additions - capital lease	—	3	—	—	3
Retirements	—	(3)	—	—	(3)
Change in foreign exchange rates	—	(1)	—	(1)	(2)
Transfers	—	13	—	(11)	2
As at Dec. 31, 2016	178	268	223	24	693
Additions	**—**	**31**	**—**	**20**	**51**
Change in foreign exchange rates	**—**	**(3)**	**—**	**—**	**(3)**
Transfers	**—**	**18**	**—**	**(15)**	**3**
As at Dec. 31, 2017	**178**	**314**	**223**	**29**	**744**
Accumulated amortization					
As at Dec. 31, 2015	109	142	52	—	303
Amortization	6	24	8	—	38
Retirements	—	(3)	—	—	(3)
As at Dec. 31, 2016	115	163	60	—	338
Amortization	**8**	**24**	**9**	**—**	**41**
Change in foreign exchange rates	**—**	**1**	**—**	**—**	**1**
Transfers	**2**	**—**	**(2)**	**—**	**—**
As at Dec. 31, 2017	**125**	**188**	**67**	**—**	**380**
Carrying amount					
As at Dec. 31, 2015	69	114	171	15	369
As at Dec. 31, 2016	63	105	163	24	355
As at Dec. 31, 2017	**53**	**126**	**156**	**29**	**364**

19. Other Assets

The components of other assets are as follows:

As at Dec. 31	2017	2016
South Hedland prepaid transmission access and distribution	**75**	–
Deferred licence fees	**13**	15
Project development costs	**53**	46
Deferred service costs	**15**	16
Mississauga long-term receivable *(Note 4)*	**—**	116
Long-term prepaids and other assets	**44**	44
Loan receivable	**33**	–
Keephills Unit 3 transmission deposit	**4**	5
Total other assets	**237**	242

South Hedland prepaid costs relate to certain prepaid electricity transmission and distribution costs that are amortized on a straigh-line basis over the South Hedland PPA contract life.

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Project development costs are primarily comprised of the Corporation's Sundance 7 and Dunvegan projects in Alberta. In December 2015, the Corporation repurchased its partner's 50 per cent share in TAMA Power, the jointly controlled entity developing the Sundance 7 project, for consideration of $10 million, payable in four years and an option for its partner to re-enter the development projects of TAMA Power at accumulated cost during this period.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

Mississauga long-term receivable relates to amounts recognized as a result of entering into the new contract. Fixed monthly payments are to be received until Dec. 31, 2018. See Notes 4 and 12 for further details.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 32.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $38 million (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022. The Corporation may, at any time, demand repayment of any advances outstanding for the purpose of funding any capital required. The current portion of $5 million is included in accounts receivable and the long-term portion of the $33 million is included in other assets.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next four years to 2021, as long as certain performance criteria are met.

20. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
Balance, Dec 31, 2015	233	165	398
Liabilities incurred	11	12	23
Liabilities settled	(23)	(36)	(59)
Accretion	19	1	20
Revisions in estimated cash flows	12	5	17
Revisions in discount rates	44	—	44
Reversals	—	(96)	(96)
Change in foreign exchange rates	(3)	(1)	(4)
Balance, Dec 31, 2016	293	50	343
Liabilities incurred	**3**	**19**	**22**
Liabilities settled	**(19)**	**(31)**	**(50)**
Liabilities disposed(1)	**(8)**	**—**	**(8)**
Accretion	**23**	**—**	**23**
Revisions in estimated cash flows(2)	**41**	**1**	**42**
Revisions in discount rates(2)	**110**	**—**	**110**
Reversals	**—**	**(4)**	**(4)**
Change in foreign exchange rates	**(6)**	**(2)**	**(8)**
Balance, Dec 31, 2017	**437**	**33**	**470**

(1) Relates to the disposition of the Solomon power station and the sale of the Wintering Hills wind facility.
(2) During 2017, mainly as a result of the OCA (see Note 4(H)), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to the use of 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec 31, 2016	293	50	343
Current portion	27	12	39
Non-current portion	266	38	304
Balance, Dec 31, 2017	**437**	**33**	**470**
Current portion	**40**	**27**	**67**
Non-current portion	**397**	**6**	**403**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1 billion, which will be incurred between 2018 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2017, the Corporation had provided a surety bond in the amount of US$139 million (2016 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2017, the Corporation had provided letters of credit in the amount of $120 million (2016 - $117 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Other Provisions

Other provisions include amounts related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used and for vacant leased premises. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2023.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

During 2015, the Corporation recorded a significant adjustment to other provisions, relating to the force majeure claim at Keephills 1. However, on Nov. 18, 2016, force majeure relief was granted to the Corporation and accordingly approximately $94 million was reversed during the last quarter of 2016 as disclosed in Note 4(I).

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

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at Dec. 31	**2017**			2016		
	Carrying value	**Face value**	**Interest**[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**27**	**27**	**2.8%**	—	—	—%
Debentures	**1,046**	**1,051**	**6.0%**	1,045	1,051	6.0%
Senior notes[3]	**1,499**	**1,510**	**6.0%**	2,151	2,158	5.0%
Non-recourse[4]	**1,022**	**1,032**	**4.3%**	1,038	1,048	4.5%
Other[5]	**44**	**44**	**9.2%**	54	54	9.2%
	3,638	**3,664**		4,288	4,311	
Finance lease obligations	**69**			73		
	3,707			4,361		
Less: current portion of long-term debt	**(729)**			(623)		
Less: current portion of finance lease obligations	**(18)**			(16)		
Total current long-term debt and finance lease obligations	**(747)**			(639)		
Total credit facilities, long-term debt, and finance lease obligations	**2,960**			3,722		

(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, 2017 - US$1.2 billion (Dec. 31, 2016 - US$1.6 billion).
(4) Includes US$27 million at Dec. 31, 2017 (Dec. 31, 2016 - US$53 million).
(5) Includes US$24 million at Dec. 31, 2017 (Dec. 31, 2016 - US$29 million) of tax equity financing.

Credit facilities are comprised of the Corporation's $1.0 billion committed syndicated bank credit facility, TransAlta Renewables $0.5 billion committed syndicated bank credit facility, and the Corporation's US$200 million and $240 million committed bilateral facilities. These facilities expire in 2021, 2021, 2020, and 2019 respectively. The $1.5 billion (Dec. 31, 2016 - $1.5 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate -in accordance with a pricing grid that is standard for such facilities.

During 2017:

- TransAlta Renewables entered into a syndicated credit agreement giving it access to a $0.5 billion committed credit facility. The agreement is fully committed for four years, expiring in 2021. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate -in accordance with a pricing grid that is standard for such facilities. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the new credit agreement, the $350 million credit facility provided by TransAlta was cancelled. The Corporation's consolidated liquidity remains unchanged, as the Corporation's credit facility decreased by $0.5 billion to $1.0 billion in total, while TransAlta Renewables' facility increased to a total of $0.5 billion; and
- the Corporation extended its four-year revolving $1.0 billion committed syndicated credit facility and three bilateral credit facilities by one year to 2021 and 2019, respectively, with key terms and covenants unchanged.

During 2016, the Corporation:

- paid out the credit facilities' balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian Assets that closed Jan. 6, 2016 (see Note 4);
- extended the four-year revolving $1.5 billion committed syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018, respectively, with key terms and covenants unchanged; and
- extended the four-year US$200 million bilateral credit facility to 2020. The amount available was reduced from US $300 million to US$200 million. The remaining key terms and covenants were unchanged.

The Corporation has a total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $500 million. In total, $1.4 billion (Dec. 31, 2016 - $1.4 billion) is not drawn. At Dec. 31, 2017, the $0.6 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, the Corporation also has $314 million of available cash and cash equivalents.

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2019 to 2030.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.9 per cent and have maturity dates ranging from 2018 to 2040.

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$480 million (2016 - US$630 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 5.36 per cent.

TransAlta Renewables closed a $260 million non-recourse bond offering on Oct. 2, 2017, by way of a private placement. At the same time, the Corporation early redeemed the $191 million face value CHD non-recourse debentures on Oct. 12, 2017. See Note 4(F) for further details.

During 2016:

- the Corporation's $27 million 5.69 per cent non-recourse debenture matured and was paid out using existing liquidity;
- the Corporation's subsidiary New Richmond Wind L.P. issued a non-recourse bond in the amount of $159 million, bearing interest at 3.963 per cent, with principal and interest payable semi-annually, and maturing on June 30, 2032 (see Note 4(M));
- the Corporation made a scheduled semi-annual $4 million principal payment on the New Richmond Wind L.P. bond;
- the Corporation made scheduled semi-annual principal payments of approximately $35 million on the Melancthon Wolfe Wind L.P. bond;
- the Corporation's subsidiary TAPC Holdings LP issued a non-recourse bond in the amount of $202.5 million, bearing a variable interest rate at the Canadian Dollar Offered Rate plus 395 basis points, with principal and interest payable quarterly, maturing on Dec. 31, 2030 (see Note 4(J)), and;
- early redeemed $10 million of non-recourse bonds, which resulted in a $1 million loss recognized in interest expense.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financing assumed in the Lakeswind wind acquisition (see Note 4(P)).

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2017, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP, and Mass Solar non-recourse bonds of $1,022 million (Dec. 31, 2016 - $845 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2018. At Dec. 31, 2017, $35 million (Dec. 31, 2016 -$24 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, 2017. However, as at Dec. 31, 2017, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letter of credits and was not available for general use.

C. Security

Non-recourse debts of $848 million in total (Dec. 31, 2016 - $644 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of $1,107 million at Dec. 31, 2017 (Dec. 31, 2016 - $956 million). At Dec. 31, 2017, a non-recourse bond of approximately $174 million (Dec. 31, 2016 - $201 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

D. Principal Repayments

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Principal repayments(1)	730	469	472	100	581	1,312	3,664

(1) Excludes impact of derivatives.

E. Restricted Cash

The Corporation has $30 million of proceeds from the KHWLP project financing which is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, including commissioning of the Kent Hills 3 wind project.

F. Finance Lease Obligations

Amounts payable for mining assets and other finance leases are as follows:

As at Dec. 31	2017		2016	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**20**	**20**	19	19
Second to fifth years inclusive	**43**	**38**	44	39
More than five years	**15**	**11**	21	15
	78	**69**	84	73
Less: interest costs	**9**	**—**	11	—
Total finance lease obligations	**69**	**69**	73	73

Included in the Consolidated Statements of Financial Position as:	2017	2016
Current portion of finance lease obligations	**18**	16
Long-term portion of finance lease obligations	**51**	57
	69	73

G. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities, and its uncommitted $100 million demand letter of credit facility. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $100 million demand letter of credit facility.

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2017, was $677 million (2016 - $566 million) with no (2016 - nil) amounts exercised by third parties under these arrangements.

22. 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	2017	2016
Defined benefit obligation *(Note 27)*	**235**	208
Deferred coal revenues	**60**	62
Long-term incentive accruals *(Note 26)*	**16**	14
Other	**48**	46
Total	**359**	330

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint operation partner for future coal deliveries. These amounts are being amortized into revenue over the life of the coal supply agreement, since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

Other includes $9 million (2016 - $10 million) relating to a reimbursement received for costs of the New Richmond terminal station, which is being amortized to revenue over the term of the related PPA.

23. 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	2017		2016	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**287.9**	**3,095**	284.0	3,077
Issued under the dividend reinvestment and share purchase plan	**—**	**—**	3.9	18
	287.9	**3,095**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**(1)**	—	(1)
Issued and outstanding, end of year	**287.9**	**3,094**	287.9	3,094

B. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 22, 2016. The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a "permitted bid" (as defined in the Shareholder Rights Plan), where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

C. Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan (the "Plan")

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan provided eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component).

The Corporation suspended the Premium Dividend™ Component of the Plan following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remained effective in accordance with their current terms. On Jan. 14, 2016, the Corporation announced the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan, in order to stop shareholder dilution.

On Jan. 1, 2016, 3.9 million common shares were issued for dividends reinvested.

D. Earnings per Share

Year ended Dec. 31	**2017**	2016	2015
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Basic and diluted weighted average number of common shares outstanding (millions)	**288**	288	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.66)**	0.41	(0.09)

E. Dividends

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually, as part of a plan to maximize the Company's long-term financial flexibility.

On Oct. 30, 2017, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2018.

On Feb. 2, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Apr. 1, 2018.

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

24. 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	2017		2016	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Sept. 17, 2017, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017 to, but excluding, Sept. 30, 2022, will be 5.194 per cent, which is equal to the five-year Government of Canada bond yield of 1.544 per cent, determined as of Aug. 31, 2017, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

II. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 16, 2017, the Corporation announced that after, taking into account all election notices received by the June 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017 to, but excluding, June 30, 2022, will be 4.027 per cent, which is equal to the five-year Government of Canada bond yield of 0.927 per cent, determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

III. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2017.

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 an annualized fixed dividend rate of 2.539 per cent, and will reset every quarter.

IV. Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, they are also:

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2017, 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	0.7255	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.2985	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.325	Sept. 30, 2019	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the preferred share dividends declared in 2017, 2016, and 2015:

	Total dividends declared ($)		
Series	**2017**	2016	2015
A	**5**	10	14
B	**1**	1	—
C	**9**	16	13
E	**8**	14	11
G	**7**	11	8
Total for the year	**30**	52	46

On Feb. 2, 2018, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.17889 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2018.

25. Accumulated Other Comprehensive Income

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2017	2016
Currency translation adjustment		
Opening balance, Jan. 1	**(1)**	52
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(89)**	(71)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[2]	**64**	18
Balance, Dec. 31	**(26)**	(1)
Cash flow hedges		
Opening balance, Jan. 1	**456**	350
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[3]	**106**	106
Balance, Dec. 31	**562**	456
Employee future benefits		
Opening balance, Jan. 1	**(38)**	(46)
Net actuarial gains (losses) on defined benefit plans, net of tax[4]	**(6)**	8
Balance, Dec. 31	**(44)**	(38)
Other		
Opening balance, Jan. 1	**(18)**	(3)
Change in ownership of TransAlta Renewables	**4**	—
Intercompany available-for-sale investments	**11**	(15)
Balance, Dec. 31	**(3)**	(18)
Accumulated other comprehensive income	**489**	399

(1) Net of income tax of 11 million for the year ended Dec. 31, 2017 (2016 - 11 million).
(2) Net of income tax of 4 million for the year ended Dec. 31, 2017 (2016 - 5 million).
(3) Net of income tax of 108 million for the year ended Dec. 31, 2017 (2016 - 51 million).
(4) Net of income tax of 4 million for the year ended Dec. 31, 2017 (2016 - 4 million).

26. 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 three performance measures: growth in funds from operation per share, growth in free cash flow per share, and growth in the Corporation's total shareholder return relative to the S&P/TSX Composite Index. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued at the end of each reporting period using the closing price of the Corporation's common shares on the Toronto Stock Exchange.

The pre-tax compensation expense related to PSUs and RSUs in 2017 was $15 million (2016 - $17 million , 2015 - $3 million reversal), 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 $1 million in 2017 (2016 - $3 million, 2015 - $2 million reversal).

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 March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance. In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance. The expense recognized relating to these grants during 2017 was approximately $1 million (2016 - less than $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2017, are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	Number of options at Dec. 31, 2017	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 8.00	1.9	5.6	6.46
22.00 - 30.00(1)	0.5	2.1	23.60
31.00 - 48.00(1)	0.5	0.1	34.35
5.00 - 48.00	**2.9**	**4.0**	**14.26**

(1) Options currently exercisable.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation extended interest-free loans (up to 30 per cent of an employee's base salary) to employees below executive level and allowed for payroll deductions over a three-year period to repay the loan. Executives were not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchased these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares were handled in the same manner. At Dec. 31, 2017, amounts receivable from employees under the plan totalled less than $1 million (2016 - $1 million).

On Jan. 14, 2016, the Corporation suspended its employee share purchase plan.

27. 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, 2017. 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, 2017.

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 2017 for the amount of $77 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2017, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2017.

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, 2017	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**1**	**10**
Administration expenses	**2**	**—**	**—**	**2**
Interest cost on defined benefit obligation	**20**	**3**	**1**	**24**
Interest on plan assets	**(15)**	**—**	**—**	**(15)**
Defined benefit expense	**14**	**5**	**2**	**21**
Defined contribution expense	**11**	**—**	**—**	**11**
Net expense	**25**	**5**	**2**	**32**

Year ended Dec. 31, 2016	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	—	—	(16)
Defined benefit expense	14	5	3	22
Defined contribution expense	15	—	—	15
Net expense	29	5	3	37

Year ended Dec. 31, 2015	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	—	—	(16)
Curtailment and amendment gain(1)	—	(5)	(3)	(8)
Defined benefit expense	14	—	—	14
Defined contribution expense	21	—	—	21
Net expense	35	—	—	35

(1) Relates to the reduction in the number of employees associated with the restructuring initiative described in Note 4(S).

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2017	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**416**	**12**	**–**	**428**
Present value of defined benefit obligation	**(561)**	**(87)**	**(27)**	**(675)**
Funded status - plan deficit	**(145)**	**(75)**	**(27)**	**(247)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(4)**	**(6)**	**(2)**	**(12)**
Other long-term liabilities	**(141)**	**(69)**	**(25)**	**(235)**
Total amount recognized	**(145)**	**(75)**	**(27)**	**(247)**

As at Dec. 31, 2016	Registered	Supplemental	Other	Total
Fair value of plan assets	423	10	–	433
Present value of defined benefit obligation	(554)	(82)	(27)	(663)
Funded status - plan deficit	(131)	(72)	(27)	(230)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(15)	(6)	(1)	(22)
Other long-term liabilities	(116)	(66)	(26)	(208)
Total amount recognized	(131)	(72)	(27)	(230)

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, 2015	429	9	–	438
Interest on plan assets	16	–	–	16
Net return on plan assets	10	–	–	10
Contributions	11	6	1	18
Benefits paid	(40)	(5)	(1)	(46)
Administration expenses	(2)	–	–	(2)
Effect of translation on US plans	(1)	–	–	(1)
As at Dec. 31, 2016	423	10	–	433
Interest on plan assets	**15**	**–**	**–**	**15**
Net return on plan assets	**26**	**–**	**–**	**26**
Contributions	**6**	**6**	**–**	**12**
Benefits paid	**(51)**	**(4)**	**–**	**(55)**
Administration expenses	**(2)**	**–**	**–**	**(2)**
Effect of translation on US plans	**(1)**	**–**	**–**	**(1)**
As at Dec. 31, 2017	**416**	**12**	**–**	**428**

The fair value of the Corporation's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2017	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**76**	**—**	**76**
US	**—**	**31**	**—**	**31**
International	**—**	**118**	**—**	**118**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**43**	**—**	**43**
AA	**—**	**71**	**—**	**71**
A	**—**	**44**	**—**	**44**
BBB	**1**	**25**	**—**	**26**
Below BBB	**—**	**5**	**—**	**5**
Money market and cash and cash equivalents	**(1)**	**14**	**—**	**13**
Total	**—**	**427**	**1**	**428**

Year ended Dec. 31, 2016	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	76	—	76
US	—	30	—	30
International	—	120	—	120
Private	—	—	2	2
Bonds				
AAA	—	47	—	47
AA	—	58	—	58
A	—	55	—	55
BBB	1	22	—	23
Below BBB	—	5	—	5
Money market and cash and cash equivalents	3	14	—	17
Total	4	427	2	433

Plan assets do not include any common shares of the Corporation at Dec. 31, 2017, and Dec. 31, 2016. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2017 (2016 - $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, 2015	566	80	32	678
Current service cost	7	2	2	11
Interest cost	21	3	1	25
Benefits paid	(40)	(5)	(1)	(46)
Actuarial gain arising from demographic assumptions	(1)	–	(4)	(5)
Actuarial loss arising from financial assumptions	2	–	–	2
Actuarial gain (loss) arising from experience adjustments	–	2	(2)	–
Effect of translation on US plans	(1)	–	(1)	(2)
Present value of defined benefit obligation as at Dec. 31, 2016	**554**	**82**	**27**	**663**
Current service cost	**7**	**2**	**1**	**10**
Interest cost	**20**	**3**	**1**	**24**
Benefits paid	**(51)**	**(4)**	**–**	**(55)**
Actuarial loss arising from demographic assumptions	**4**	**1**	**–**	**5**
Actuarial loss arising from financial assumptions	**26**	**3**	**–**	**29**
Actuarial (gain) loss arising from experience adjustments	**3**	**–**	**(1)**	**2**
Effect of translation on US plans	**(2)**	**–**	**(1)**	**(3)**
Present value of defined benefit obligations as at Dec. 31, 2017	**561**	**87**	**27**	**675**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2017 is 14.6.

F. Contributions

The expected employer contributions for 2018 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**4**	**6**	**2**	**12**

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, 2017			As at Dec. 31, 2016		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.3**	**3.3**	**3.4**	3.7	3.6	3.7
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health care cost trend rate						
Health care cost escalation	**—**	**—**	**7.8**(1)	—	—	7.9(3)
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.7**	**3.6**	**3.7**	3.8	3.8	3.8
Rate of compensation increase	**2.6**	**3.0**	**—**	3.0	3.0	—
Assumed health care cost trend rate						
Health care cost escalation	**—**	**—**	**7.9**(2)	—	—	7.8(4)
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health care premium escalation	**—**	**—**	**—**	—	—	5.0

(1) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.30% per year to 5% in 2024 for Canada.
(3) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.30% per year to 5% in 2024 for Canada.
(4) Post- and Pre 65 rates: decreasing gradually to 5% by 2024 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			**US plans**	
Year ended Dec. 31, 2017	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**79**	**12**	**3**	**3**	**1**
1% increase in the salary scale	**10**	**1**	**—**	**—**	**—**
1% increase in the health care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**2**	**—**	**1**	**—**

28. Joint Arrangements

Joint arrangements at Dec. 31, 2017, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

29. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2017**	2016	2015
(Use) source:			
Accounts receivable	**(228)**	(23)	(77)
Prepaid expenses	**(75)**	5	(3)
Income taxes receivable	**8**	(4)	1
Inventory	**(7)**	11	(9)
Accounts payable, accrued liabilities, and provisions	**186**	81	(152)
Income taxes payable	**2**	3	(2)
Change in non-cash operating working capital	**(114)**	73	(242)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2016	**Cash flows**	**New leases**	**Dividends declared**	**Foreign exchange impact**	**Other**	**Balance Dec. 31, 2017**
Long-term debt and finance lease obligations	4,361	(545)	14	—	(115)	(8)	3,707
Dividends payable (common and preferred)	54	(86)	—	64	—	2	34
Total liabilities from financing activities	**4,415**	**(631)**	**14**	**64**	**(115)**	**(6)**	**3,741**

30. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2017	2016	Increase/ (decrease)
Long-term debt[1]	**3,707**	4,361	**(654)**
Equity			
Common shares	**3,094**	3,094	**—**
Preferred shares	**942**	942	**—**
Contributed surplus	**10**	9	**1**
Deficit	**(1,209)**	(933)	**(276)**
Accumulated other comprehensive income	**489**	399	**90**
Non-controlling interests	**1,059**	1,152	**(93)**
Less: available cash and cash equivalents[2]	**(314)**	(305)	**(9)**
Less: fair value asset of hedging instruments on long-term debt[3]	**(30)**	(163)	**133**
Total capital	**7,748**	8,556	**(808)**

(1) Includes finance lease obligations, amounts outstanding under credit facilities, tax equity liability, and current portion of long-term debt.
(2) The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available, and used to facilitate repayment of debt.
(3) The Corporation includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

In 2016 and 2017, the Corporation focused on raising non-recourse debt to fund upcoming corporate debt maturities. The Corporation's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2016, and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios, and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

The Corporation has an investment grade credit rating from Standard & Poor's (negative outlook), DBRS (stable outlook) and Fitch Ratings (stable outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook. During 2017, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable, DBRS changed the Corporation's Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating from BBB to BBB (low) (with outlook changed to stable from negative), and Standard & Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB-, but changed the outlook from stable to negative. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Strengthening the Corporation's financial position allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles.

As at Dec. 31	2017	2016	Target
Comparable funds from operations to adjusted interest coverage (times)	4.3	3.9	4 to 5
Adjusted comparable funds from operations to adjusted net debt (%)	20.4	16.3	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization (times)	3.6	3.8	3.0 to 3.5

Comparable Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as comparable FFO plus interest on debt (net of capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares. Comparable 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. Comparable FFO to adjusted interest coverage in 2017 improved compared with 2016. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted Comparable FFO to Adjusted Net Debt is calculated as comparable FFO less 50 per cent of dividends paid on preferred shares divided by net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents and including fair value assets of hedging instruments on debt). Adjusted comparable FFO to adjusted net debt increased in 2017 compared to 2016 due to the increase in comparable FFO, and lower debt due to repayments. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA") is calculated as net debt divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation, and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. Adjusted net debt to comparable EBITDA in 2017 improved compared to 2016 due to the lower debt balance due to repayments. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2017, the Corporation continued to strengthen its financial position and reduce debt; using proceeds from the dropdown of the Canadian Assets to pay out the credit facility balance. In 2016, the Corporation reduced its dividend to $0.16 per common share on an annualized basis from $0.72 per common share.

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 Property, Plant, and Equipment, and Make Acquisitions

For the years ended Dec. 31, 2017 and 2016, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	**2017**	2016	**Increase (decrease)**
Cash flow from operating activities	**626**	744	(118)
Change in non-cash working capital	**114**	(73)	187
Cash flow from operations before changes in working capital	**740**	671	69
Dividends paid on common shares	**(46)**	(69)	23
Dividends paid on preferred shares	**(40)**	(42)	2
Distributions paid to subsidiaries' non-controlling interests	**(172)**	(151)	(21)
Property, plant, and equipment expenditures[1]	**(338)**	(358)	20
Inflow	**144**	51	223

(1) Includes growth capital associated with the South Hedland Power Station.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2017, $1.4 billion (2016 - $1.4 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges. TransAlta is focused on replacing additional maturing recourse debt with debt secured by contracted cash flows.

31. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2017 are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	64.0	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	2017	2016	2015
Total compensation	**24**	20	9
Comprised of:			
Short-term employee benefits	**14**	8	8
Post-employment benefits	**2**	2	2
Termination benefits	**—**	—	1
Share-based payments	**8**	10	(2)

32. 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:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Natural gas, transportation, and other purchase contracts	48	7	5	5	4	29	**98**
Transmission	9	6	6	3	—	—	**24**
Coal supply and mining agreements	155	159	161	23	14	96	**608**
Long-term service agreements	108	50	41	31	15	35	**280**
Non-cancellable operating leases[1]	9	9	9	9	9	111	**156**
Growth	27	—	—	—	—	—	**27**
TransAlta Energy Transition Bill	6	6	6	6	6	6	**36**
Total	**362**	**237**	**228**	**77**	**48**	**277**	**1,229**

(1) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.

A. Natural Gas, Transportation, and Other Purchase Contracts
Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other purchase contracts relate to commitments for goods and services.

B. Transmission
The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements
Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2020.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements. Some of these commitments have been reduced, due to the cessation of coal-fired emissions from the Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

D. Long-Term Service Agreements
TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities, and turbines at various wind facilities.

E. Non-Cancellable Operating Leases
TransAlta has operating leases in place for buildings, vehicles, and various types of equipment and commitments for water rights and transmission tower right of ways.

During the year ended Dec. 31, 2017, $7 million (2016 - $9 million, 2015 - $9 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2017 and 2016 were less than $1 million (2015 - less than $1 million). No contingent rental payments were made in respect of these operating leases.

F. Growth

Commitments for growth relate to the construction of the Kent Hills 3 wind project.

G. TransAlta Energy Transition Bill Commitments

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining 9 year life of the Centralia coal plant to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Dec. 31, 2017, the Corporation has funded approximately US$28 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 (the "LLRP") before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the Alberta Electric System Operator to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if the Corporation and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil. The Corporation has therefore recorded a provision of $7.5 million.

II. FMG Disputes

The Corporation is currently engaged in litigation with FMG as a result of their purported termination of the South Hedland PPA. In addition, FMG withheld approximately AUD$58.2 million, including AUD$43 million in tax applicable to the repurchase of the Solomon Power Station. TransAlta is seeking payment of all withheld amounts, and has currently commenced proceedings to recover approximately AUD$54.1 million by filing and serving FMG with a Writ and Statement of Claim on Nov. 17, 2017, and also applied for summary judgment for this amount. The hearing is scheduled for March 23, 2018.

33. 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, 2017	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	999	435	261	135	287	121	69	—	2,307
Fuel and purchased power	585	293	101	14	17	6	—	—	1,016
Gross margin	414	142	160	121	270	115	69	—	1,291
Operations, maintenance, and administration	192	51	50	31	48	37	24	84	517
Depreciation and amortization	317	73	38	37	111	31	2	26	635
Asset impairment charge	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	13	4	1	—	8	3	—	1	30
Net other operating 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 and other									2
Losses before income taxes									(54)

Year ended Dec 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	1,048	354	402	119	272	126	76	—	2,397
Fuel and purchased power	451	281	185	20	18	8	—	—	963
Gross margin	597	73	217	99	254	118	76	—	1,434
Operations, maintenance, and administration	178	54	54	25	52	33	24	69	489
Depreciation and amortization	242	61	100	17	119	33	3	26	601
Asset impairment charge	—	—	—	—	28	—	—	—	28
Restructuring provision	—	—	—	—	—	—	—	1	1
Taxes, other than income taxes	13	4	1	1	8	3	—	1	31
Net other operating (income) loss	(2)	—	(191)	—	(1)	—	—	—	(194)
Operating income (loss)	166	(46)	253	56	48	49	49	(97)	478
Finance lease income	—	—	14	52	—	—	—	—	66
Net interest expense									(229)
Foreign exchange loss									(5)
Gain on sale of assets									4
Earnings before income taxes									314

Year ended Dec 31, 2015	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	912	372	454	114	250	116	49	—	2,267
Fuel and purchased power	441	316	204	20	19	8	—	—	1,008
Gross margin	471	56	250	94	231	108	49	—	1,259
Operations, maintenance, and administration	194	50	67	21	48	29	12	71	492
Depreciation and amortization	237	63	75	20	99	25	1	25	545
Asset impairment reversals	—	(2)	—	—	—	—	—	—	(2)
Restructuring provision	11	1	1	—	—	—	3	6	22
Taxes, other than income taxes	12	3	3	—	7	3	—	1	29
Net other operating (income) losses	(7)	—	—	—	—	(24)	56	—	25
Operating income (loss)	24	(59)	104	53	77	75	(23)	(103)	148
Finance lease income	—	—	9	49	—	—	—	—	58
Gain on sale of assets	—	—	262	—	—	—	—	—	262
Net interest expense									(251)
Foreign exchange gain									4
Earnings before income taxes									221

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2017 is $18 million (2016 -$19 million, 2015 - $20 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases, is included in revenues, and was $247 million for the year ended Dec. 31, 2017 (2016 - $221 million, 2015 - $230 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec 31, 2017	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	—	—	—	—	**174**	**259**	**30**	—	**463**
PP&E	**2,902**	**370**	**416**	**606**	**1,764**	**497**	**1**	**22**	**6,578**
Intangible assets	**91**	**7**	**3**	**42**	**149**	**3**	**13**	**56**	**364**

As at Dec 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	—	—	—	—	175	259	30	—	464
PP&E	3,069	428	414	527	1,856	503	2	25	6,824
Intangibles	93	7	4	12	163	3	15	58	355

III. Selected Consolidated Statements of Cash Flows Information
Additions to non-current assets are as follows:

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**

Year ended Dec 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	159	15	11	107	16	43	—	7	358
Intangibles	3	1	1	—	—	—	—	16	21

Year ended Dec 31, 2015	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	179	13	19	204	13	43	1	4	476
Intangibles	6	—	—	—	—	—	3	17	26

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	**2017**	2016	2015
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**635**	601	545
Depreciation included in fuel and purchased power *(Note 5)*	**73**	63	59
Loss on disposal of property, plant, and equipment	**—**	—	1
Depreciation and amortization on the Consolidated Statements of Cash Flows	**708**	664	605

C. Geographic Information
I. Revenues

Year ended Dec. 31	**2017**	2016	2015
Canada	**1,663**	1,828	1,705
US	**509**	450	448
Australia	**135**	119	114
Total revenue	**2,307**	2,397	2,267

II. Non-Current Assets

	Property, plant, and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Canada	**5,353**	5,583	**297**	315	**105**	184	**417**	417
US	**619**	714	**25**	28	**43**	42	**46**	47
Australia	**606**	527	**42**	12	**89**	16	**—**	—
Total	**6,578**	6,824	**364**	355	**237**	242	**463**	464

D. Significant Customer

During the year ended Dec. 31, 2017, sales to one customer represented 28 per cent, of the Corporation's total revenue (2016 - two customers representing 25 per cent and 16 per cent, respectively).

34. Subsequent Events

A. Normal Course Issuer Bid

On March 1, 2018, the Corporation announced that it intends to seek Toronto Stock Exchange ("TSX") acceptance of a normal course issuer bid ("NCIB"). The Board has authorized the repurchases of up to 14,000,000 of its 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.

B. Early Redemption of Senior Notes Due 2018

On Feb. 2, 2018, the Corporation announced it called for the redemption of its outstanding US$500 million 6.65 per cent senior notes maturing May 15, 2018 (the "Senior Notes"). The Senior Notes will be redeemed on March 15, 2018, at a price equal to the greater of: i) 100 per cent of the principal amount of the Senior Notes and ii) the sum of the present values of the remaining scheduled payments of principal and interest thereon discounted to the redemption date on a semi-annual basis at the treasury rate plus 45 basis points, plus in each case, accrued interest thereon to the date of redemption.

C. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it entered into an arrangement to acquire two construction-ready projects in the Northeastern United States.

The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA and ii) a 29 MW project located in New Hampshire with two 20-year PPAs. All three counterparties have Standard & Poor's credit ratings of A+ or better.

The total cost of the two projects is estimated to be US$240 million, of which approximately 70% will be funded in 2018 and the remainder in 2019. The commercial operation date for both projects is expected during the second half of 2019.

TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.

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, 2017:

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

0.57 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.