TransAlta Corporation

Consolidated Financial Statements

December 31, 2019

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

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

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

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

Dawn L. Farrell
President and Chief Executive Officer
Mar. 3, 2020

Todd Stack
Chief Financial Officer

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

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

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

TransAlta proportionately consolidates the accounts of the Sheerness, Pioneer Pipeline and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2019 Consolidated Financial Statements of TransAlta included $359 million and $326 million of total and net assets, respectively, as of Dec. 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2019, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2019, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell
President and Chief Executive Officer

Todd Stack
Chief Financial Officer

Mar. 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting
We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2019 and 2018, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated March 3, 2020 expressed an unqualified opinion thereon.

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

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

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

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations, which are included in the 2019 consolidated financial statements of TransAlta Corporation and constituted $359 million and $326 million of total and net assets, respectively, as of December 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada
March 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements
We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Corporation") as of December 31, 2019 and 2018, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows, for each of the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Adoption of IFRS 16
As discussed in Note 3 to the consolidated financial statements, the Corporation changed its method of accounting for leases in 2019 due to the adoption of *IFRS 16 - Leases*.

Report on Internal Control Over Financial Reporting
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 3, 2020 expressed an unqualified opinion thereon.

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

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

Critical Audit Matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Long-lived Assets within the US Coal segment & Goodwill related to the Wind and Solar segment

Description of the Matter

As disclosed in notes 2(I), (J), 7, 17, and 20 of the consolidated financial statements, the Corporation owns significant power generation assets which are required to be reviewed for indicators of impairment or impairment reversal at the cash generating unit ("CGU") level and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually. Long lived assets for the US Coal segment amount to $352 million. Goodwill related to the Wind and Solar segment amounts to $176 million.

We identified the assessment of indicators of impairment or impairment reversal for the CGUs within the US Coal segment as a critical audit matter because it involves auditing the judgment applied by management to assess various external and internal sources of information, more specifically if significant changes with an adverse effect on the Corporation have taken place during the year, or will take place in the near future, in the market or economic environment. Determining the recoverable amount for those CGUs for which indicators of impairment or impairment reversal are present within the US Coal segment, as well as determining the recoverable amount for the Wind and Solar segment for the purposes of the annual goodwill impairment test was also identified as a critical audit matter because it involves significant estimation with a high degree of subjectivity including forecasting future cash flows, generation profiles, and commodity prices, and determining the appropriate discount rate.

How We Addressed the Matter in Our Audit

We obtained an understanding of management's process for performing their assessment of indicators of impairment or impairment reversal and the estimation of the recoverable amount. We evaluated the design and tested the operating effectiveness of controls over the Corporation's processes to identify indicators and determine the recoverable amount. Our audit procedures to test the indicators assessment included, among others, evaluating the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. Our audit procedures to test the Corporation's recoverable amount of various CGUs included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical power generation data to evaluate future generation forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking against available market views.

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(Y)(IV) and 14 of the consolidated financial statements, the Corporation enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as Level III are determined using assumptions that are not readily observable. As at December 31, 2019 the Corporation's derivative financial instruments classified as level III were $686 million.

How We Addressed the Matter in Our Audit

Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future commodity prices, volatility, unit availability, demand profiles, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.

We obtained an understanding of the Corporation's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also utilized third-party data to test management's future pricing assumptions, credit valuation adjustments, and liquidity assumptions as well as comparing terms such as volumes and timing to executed commodity contracts. We performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of level III fair value. For a sample of new level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates.

Ernst & Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947
Calgary, Canada
March 3, 2020

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2019**	2018	2017
Revenues (Note 5)	**2,347**	2,249	2,307
Fuel, carbon compliance and purchased power (Note 6)	**1,086**	1,100	1,016
Gross margin	**1,261**	1,149	1,291
Operations, maintenance and administration (Note 6)	**475**	515	517
Depreciation and amortization	**590**	574	635
Asset impairment charge (Note 7)	**25**	73	20
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	**(88)**	—	—
Taxes, other than income taxes	**29**	31	30
Termination of Sundance B and C PPAs (Note 4(E))	**(56)**	(157)	—
Net other operating income (Note 9)	**(49)**	(47)	(49)
Operating income	**335**	160	138
Finance lease income	**6**	8	54
Net interest expense (Note 10)	**(179)**	(250)	(247)
Foreign exchange loss	**(15)**	(15)	(1)
Gain on sale of assets and other (Note 4(D) and 17)	**46**	1	2
Earnings (loss) before income taxes	**193**	(96)	(54)
Income tax expense (recovery) (Note 11)	**17**	(6)	64
Net earnings (loss)	**176**	(90)	(118)

Net earnings (loss) attributable to:			
TransAlta shareholders	**82**	(198)	(160)
Non-controlling interests (Note 12)	**94**	108	42
	176	(90)	(118)

Net earnings (loss) attributable to TransAlta shareholders	**82**	(198)	(160)
Preferred share dividends (Note 27)	**30**	50	30
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Weighted average number of common shares outstanding in the year *(millions)*	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 26)	**0.18**	(0.86)	(0.66)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Net earnings (loss)	**176**	(90)	(118)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**(26)**	15	(6)
Losses on derivatives designated as cash flow hedges, net of tax	**—**	—	(1)
Total items that will not be reclassified subsequently to net earnings	**(26)**	15	(7)
Gains (losses) on translating net assets of foreign operations, net of tax	**(59)**	84	(80)
Reclassification of translation gains on net assets of divested foreign operations[(2)]	**—**	—	(9)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(3)]	**21**	(41)	50
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[(4)]	**—**	—	14
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(5)]	**61**	(8)	214
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(6)]	**(42)**	(46)	(107)
Total items that will be reclassified subsequently to net earnings	**(19)**	(11)	82
Other comprehensive income (loss)	**(45)**	4	75
Total comprehensive income (loss)	**131**	(86)	(43)

Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**54**	(210)	(74)
Non-controlling interests (Note 12)	**77**	124	31
	131	(86)	(43)

(1) Net of income tax recovery of $7 million for the year ended Dec. 31, 2019 (2018 - $5 million expense, 2017 - $(4) million recovery).
(2) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $11 million expense).
(3) Net of income tax expense of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $2 million expense).
(4) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $2 million recovery).
(5) Net of income tax expense of $16 million for the year ended Dec. 31, 2019 (2018 - $1 million recovery, 2017 - $77 million recovery).
(6) Net of reclassification of income tax expense of $10 million for the year ended Dec. 31, 2019 (2018 - $11 million expense, 2017 - $31 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018
Cash and cash equivalents	**411**	89
Restricted cash (Note 23)	**32**	66
Trade and other receivables (Note 13)	**462**	756
Prepaid expenses	**19**	13
Risk management assets (Note 14 and 15)	**166**	146
Inventory (Note 16)	**251**	242
	1,341	1,312
Long-term portion of finance lease receivables (Note 8)	**176**	191
Risk management assets (Note 14 and 15)	**640**	662
Property, plant and equipment (Note 17)		
Cost	**13,395**	13,202
Accumulated depreciation	**(7,188)**	(7,038)
	6,207	6,164
Right of use assets (Note 18)	**146**	—
Intangible assets (Note 19)	**318**	373
Goodwill (Note 20)	**464**	464
Deferred income tax assets (Note 11)	**18**	28
Other assets (Note 21)	**198**	234
Total assets	**9,508**	9,428
Accounts payable and accrued liabilities	**413**	496
Current portion of decommissioning and other provisions (Note 22)	**58**	70
Risk management liabilities (Note 14 and 15)	**81**	90
Current portion of contract liabilities (Note 5)	**1**	8
Income taxes payable	**14**	10
Dividends payable (Note 26 and 27)	**37**	58
Current portion of long-term debt and lease obligations (Note 23)	**513**	148
	1,117	880
Credit facilities, long-term debt and lease obligations (Note 23)	**2,699**	3,119
Exchangeable securities (Note 14 and 24)	**326**	—
Decommissioning and other provisions (Note 22)	**488**	386
Deferred income tax liabilities (Note 11)	**472**	501
Risk management liabilities (Note 14 and 15)	**29**	41
Contract liabilities (Note 5)	**14**	80
Defined benefit obligation and other long-term liabilities (Note 25)	**301**	287
Equity		
Common shares (Note 26)	**2,978**	3,059
Preferred shares (Note 27)	**942**	942
Contributed surplus	**42**	11
Deficit	**(1,455)**	(1,496)
Accumulated other comprehensive income (Note 28)	**454**	481
Equity attributable to shareholders	**2,961**	2,997
Non-controlling interests (Note 12)	**1,101**	1,137
Total equity	**4,062**	4,134
Total liabilities and equity	**9,508**	9,428

Significant and subsequent events (Note 4)
Commitments and contingencies (Note 35)

Gordon D. Giffin

On behalf of the Board: Gordon D. Giffin, Director; Beverlee F. Park, Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[(1)]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2017	$3,094	$942	$10	$ (1,209)	$489	$3,326	$1,059	$4,385
Impact of change in accounting policy	—	—	—	(14)	—	(14)	1	(13)
Adjusted balance as at Jan. 1, 2018	3,094	942	10	(1,223)	489	3,312	1,060	4,372
Net earnings (loss)	—	—	—	(198)	—	(198)	108	(90)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	43	43	—	43
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(54)	(54)	—	(54)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	15	15	—	15
Intercompany FVOCI investments	—	—	—	—	(16)	(16)	16	—
Total comprehensive income (loss)				(198)	(12)	(210)	124	(86)
Common share dividends	—	—	—	(57)	—	(57)	—	(57)
Preferred share dividends	—	—	—	(50)	—	(50)	—	(50)
Shares purchased under NCIB	(35)	—	—	12	—	(23)	—	(23)
Changes in non-controlling interests in TransAlta Renewables (Note 4(N) and 12)	—	—	—	20	4	24	133	157
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(180)	(180)
Balance, Dec. 31, 2018	3,059	942	11	(1,496)	481	2,997	1,137	4,134
Impact of change in accounting policy (Note 3)	**—**	**—**	**—**	**3**	**—**	**3**	**—**	**3**
Adjusted balance as at Jan. 1, 2019	**3,059**	**942**	**11**	**(1,493)**	**481**	**3,000**	**1,137**	**4,137**
Net earnings	**—**	**—**	**—**	**82**	**—**	**82**	**94**	**176**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(38)**	**(38)**	**—**	**(38)**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**19**	**19**	**—**	**19**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(26)**	**(26)**	**—**	**(26)**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**17**	**17**	**(17)**	**—**
Total comprehensive income (loss)				**82**	**(28)**	**54**	**77**	**131**
Common share dividends	**—**	**—**	**—**	**(34)**	**—**	**(34)**	**—**	**(34)**
Preferred share dividends	**—**	**—**	**—**	**(30)**	**—**	**(30)**	**—**	**(30)**
Shares purchased under NCIB	**(83)**	**—**	**—**	**15**	**—**	**(68)**	**—**	**(68)**
Changes in non-controlling interests in TransAlta Renewables	**—**	**—**	**—**	**5**	**1**	**6**	**22**	**28**
Effect of share-based payment plans (Note 29)	**2**	**—**	**31**	**—**	**—**	**33**	**—**	**33**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(135)**	**(135)**
Balance, Dec.31, 2019	**2,978**	**942**	**42**	**(1,455)**	**454**	**2,961**	**1,101**	**4,062**

(1) Refer to Note 28 for details on components of, and changes in, accumulated other comprehensive income (loss).
See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Operating activities			
Net earnings (loss)	**176**	(90)	(118)
Depreciation and amortization (Note 36)	**709**	710	708
Net gain (loss) on sale of assets (Note 4(D) and 17)	**(45)**	—	(1)
Accretion of provisions (Note 22)	**23**	24	23
Decommissioning and restoration costs settled (Note 22)	**(34)**	(31)	(19)
Deferred income tax recovery (Note 11)	**(18)**	(34)	(15)
Unrealized (gain) loss from risk management activities	**(32)**	30	(48)
Unrealized foreign exchange loss	**13**	28	22
Provisions	**13**	7	(7)
Asset impairment charge (Note 7)	**25**	73	20
Other non-cash items	**(102)**	147	175
Cash flow from operations before changes in working capital	**728**	864	740
Change in non-cash operating working capital balances (Note 32)	**121**	(44)	(114)
Cash flow from operating activities	**849**	820	626
Investing activities			
Additions to property, plant and equipment (Note 17 and 36)	**(417)**	(277)	(338)
Additions to intangibles (Note 19 and 36)	**(14)**	(20)	(51)
Restricted cash (Note 23)	**34**	(35)	(30)
Loan receivable (Note 21)	**(10)**	1	(38)
Acquisitions, net of cash acquired (Note 4)	**(117)**	(30)	—
Investment in the Pioneer Pipeline (Note 4(H))	**(83)**	(15)	—
Proceeds on sale of property, plant and equipment	**13**	2	3
Proceeds on sale of Wintering Hills facility and Solomon disposition (Note 4(T) and 4(X))	**—**	2	478
Income tax expense on Solomon disposition (Note 4(T) and 11)	**—**	—	(56)
Realized gains on financial instruments	**3**	2	6
Decrease in finance lease receivable	**24**	59	59
Other	**23**	13	(3)
Change in non-cash investing working capital balances	**32**	(96)	57
Cash flow from (used in) investing activities	**(512)**	(394)	87
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 23)	**(119)**	312	26
Repayment of long-term debt (Note 23)	**(96)**	(1,179)	(814)
Issuance of long-term debt (Note 23)	**166**	345	260
Issuance of exchangeable securities (Note 24)	**350**	—	—
Dividends paid on common shares (Note 26)	**(45)**	(46)	(46)
Dividends paid on preferred shares (Note 27)	**(40)**	(40)	(40)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4(O))	**—**	144	—
Repurchase of common shares under NCIB (Note 26)	**(68)**	(23)	—
Realized gains on financial instruments	**—**	48	106
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(106)**	(165)	(172)
Decrease in lease obligations (Note 23)	**(21)**	(18)	(17)
Financing fees and other	**(35)**	(31)	(6)
Change in non-cash financing working capital balances	**—**	2	—
Cash flow used in financing activities	**(14)**	(651)	(703)
Cash flow from (used in) operating, investing, and financing activities	**323**	(225)	10
Effect of translation on foreign currency cash	**(1)**	—	(1)
Increase (decrease) in cash and cash equivalents	**322**	(225)	9
Cash and cash equivalents, beginning of year	**89**	314	305
Cash and cash equivalents, end of year	**411**	89	314
Cash income taxes paid	**35**	87	14
Cash interest paid	**185**	188	230

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

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

II. Energy Marketing Segment

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

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

III. Corporate

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

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on Mar. 3, 2020.

C. Basis of Consolidation

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

2. Significant Accounting Policies

A. Revenue Recognition

I. Revenue from Contracts with Customers - 2019 and 2018 Policy

The Corporation adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018.

The Corporation elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and elected to apply IFRS 15 only to contracts that are active at the date of initial adoption. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to section III below for the accounting policy for years prior to 2018.

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

Performance Obligations

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

Transaction Price

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

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

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

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

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

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

II. Revenue from Other Sources
Lease Revenue
In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Corporation retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

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

III. Revenue Recognition Policy Prior to 2018

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

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

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

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

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

Classification and Measurement

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

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

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

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the US where project investors acquire an equity investment in the project entity and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Corporation then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity financings will be classified as a non-controlling interest. In applying the effective interest method to tax equity financings, the Corporation has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

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

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

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

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

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

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

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

Impairment of Financial Assets

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

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

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

II. Hedges

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

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

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

Fair Value Hedges

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

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

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

Cash Flow Hedges

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

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

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

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

III. Financial Instruments and Hedges Accounting Policy Prior to 2018

Financial Instruments

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

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

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

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

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

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

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

Hedges

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

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

Fair Value Hedges

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. Emission Credits and Allowances
Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Corporation records the credits using the specific identification method. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

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

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

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

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

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

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

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

Coal generation	2-10 years
Pipeline	50 years
Gas generation	2-30 years
Hydro generation	2-60 years
Wind generation	2-30 years
Mining property and equipment	2-10 years
Capital spares and other	2-60 years

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

H. Intangible Assets

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

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

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

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

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

Software	2-7 years
Power sale contracts	1-20 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

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

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

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

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

P. Assets Held for Sale

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

Q. Leases

I. 2019 Lease Policy

The Corporation adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. As a result, in 2019, the Corporation changed its accounting policy for leases, which is outlined below. Refer to (II) below for information on the prior accounting policy.

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

Lessee

The Corporation enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Corporation is the lessee, and which are not exempt as short-term or low-value leases, the Corporation:

- Recognizes right of use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right of use assets and interest expense on lease obligations in the Consolidated Statements of Earnings (loss); and
- Recognizes the principal repayments on lease obligations as financing activities and interest payments on lease obligations as operating activities in the Consolidated Statements of Cash Flow.

For short-term and low-value leases, the Corporation recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right of use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right of use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation’s estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the carrying amount of the right of use asset, or is recorded in profit or loss if the carrying amount of the right of use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Corporation is reasonably certain to exercise that option and periods covered by an option to terminate if the Corporation is reasonably certain not to exercise that option.

Right of use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right of use asset reflects that the Corporation expects to exercise the purchase option, the related right of use asset is depreciated over the useful life of the underlying asset.

The Corporation has elected to apply the practical expedient that permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement.

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

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

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

When the Corporation has subleased all or a portion of an asset it is leasing and for which it remains the primary obligor under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right of use asset arising from the head lease.

II. Lease Policy Prior to 2019
A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

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

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

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

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

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

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

S. Non-Controlling Interests

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

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

T. Joint Arrangements

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

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

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

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

U. Government Incentives

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

V. Earnings per Share

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

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

W. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

In 2019, the Corporation early-adopted amendments to IFRS 3 *Business Combinations* in advance of the mandatory effective date of Jan. 1, 2020. The amendments, among other things, introduced an optional fair value concentration test that can be applied on a transaction-by-transaction basis, to permit a simplified assessment of whether an acquired set of activities and assets are not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Corporation may elect to treat the acquisition as an asset acquisition and not as a business combination.

X. Stripping Costs

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

Y. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

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

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2017 to 2019 is found in Notes 7, 17 and 20.

II. Leases

In determining whether the Corporation's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Corporation is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes

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

IV. Financial Instruments and Derivatives

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

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

When the Corporation enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Corporation must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Corporation's expected purchase, sale or usage requirements (i.e. normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Corporation considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate, and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion.

V. Project Development Costs

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

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 22. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2019 in respect of decommissioning and restoration provisions can be found in Note 3(A)(IV) and Notes 7 and 22.

VII. Useful Life of PP&E

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

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 30 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, the Corporation recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 22 with respect to other provisions.

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

In determining the transaction price and estimates of variable consideration, management considers past history of customer usage in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets. The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements
Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, which classification affects the accounting for the joint arrangement. In making this classification, the Corporation exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

3. Accounting Changes

A. Current Accounting Changes

I. IFRS 16 *Leases*

The Corporation adopted IFRS 16 with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* ("IAS 17") or International Financial Reporting Interpretations Committee Interpretation 4 *Determining Whether an Arrangement Contains a Lease*.

The Corporation elected to adopt IFRS 16 using the modified retrospective approach on transition. The Corporation applied the definition of a lease and related guidance set out in IFRS 16 to all lease contracts in existence at Dec. 31, 2018. All relevant contractual arrangements outstanding at that date were reviewed to assess if the contract meets the new definition of a lease.Comparative information has not been restated and is reported under IAS 17. Refer to Note 2(Q)(II) for details on the accounting policy in prior years.

The Corporation recognized the cumulative impact of the initial application of the standard of $3 million in deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019, and for low value leases;
- Excluded initial direct costs from the measurement of the right of use asset at the date of initial application;
- Used hindsight to determine the lease term where the contract contained options to extend or terminate the lease;
- Adjusted the right of use assets by the amount relating to onerous contract provisions as defined under IAS 37 *Provisions, contingent liabilities and contingent assets* ("IAS 37") immediately before the date of initial application; and
- Measured the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments related to that lease that was recognized in the statement of financial position immediately before the date of initial application.

Impact on the Financial Statements

Lessee

The Corporation recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on Jan. 1, 2019, was 5.71 per cent.

The following table reconciles the Corporation's operating lease commitments at Dec. 31, 2018, as previously disclosed in the Corporation’s 2018 annual consolidated financial statements, to the lease obligations recognized on initial application of IFRS 16 and included in credit facilities, long-term debt and lease obligations on the Consolidated Statements of Financial Position as at Jan. 1, 2019:

Non-cancellable operating lease commitments disclosed at Dec. 31, 2018	80
Less: Exemption for low-value leases	(1)
Add: Extension and termination options reasonably certain to be exercised	4
Undiscounted lease liability	83
Discounted using the incremental borrowing rate at Jan. 1, 2019	(31)
New lease liabilities recognized as at Jan. 1, 2019	52
Add: 2018 finance lease obligations	63
Less: 2018 finance lease obligations that do not meet the IFRS 16 definition of a lease	(32)
Lease liabilities as at Jan. 1, 2019	**83**

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of $85 million, including $38 million that was previously included in PP&E, intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16 resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in deficit.

Lessor
Several of the Corporation's long-term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these contracts are now accounted for applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

For further details on the lease policy under IFRS 16, refer to Note 2(Q)(I) and to Note 18 for a summary of the Corporation's leases.

II. IFRS 3 Business Combinations
Effective Oct. 1, 2019, the Corporation early-adopted amendments to IFRS 3 *Business Combinations* ("IFRS 3 amendments"), in advance of its mandatory effective date of Jan. 1, 2020. The Corporation adopted the IFRS 3 amendments prospectively and therefore the comparative information presented for 2018 has not been restated. The IFRS 3 amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. Specifically, these amendments:

- Clarify the minimum requirements for a business, whereby at minimum, an input and a substantive process that together significantly contribute to the ability to create output must be present;
- Remove the assessment of whether market participants are capable of replacing any missing elements so that the assessment is based on what has been acquired in its current state and condition, rather than on whether market participants are capable of replacing any missing elements, for example, by integrating the acquired activities and assets;
- Add guidance to help entities assess whether an acquired process is substantive, which requires more persuasive evidence when there are no outputs, because the existence of outputs provides some evidence that the acquired set of activities and assets is a business;
- Narrow the definition of outputs to focus on goods or services provided to customers, investment income or other income from ordinary activities; and
- Introduce an optional fair value concentration test that can be applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets are not a business. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The Corporation elected to apply the optional fair value concentration test to its acquisition of the remaining 50 per cent interest in Keephills 3 (refer to Note 4(D) for further details). There are no other impacts to the asset acquisitions that were completed during the year ended Dec. 31, 2019.

III. IFRIC 23 - Uncertainty over Income Tax Treatments
The Corporation adopted IFRIC *23 Uncertainty over Income Tax Treatments* on its effective date of Jan. 1, 2019 and applied it retrospectively. No cumulative effect of initially applying the guidance arose. The Interpretation clarifies the application of recognition and measurement requirements in IAS 12 *Income Taxes* when there is uncertainty over income tax treatments and provides guidance on: considering uncertain tax treatments separately or together; examination by tax authorities; the appropriate method to reflect uncertainty; and accounting for changes in facts and circumstances.

IV. Change in Estimates
Canadian Coal
During the third quarter of 2019, the Corporation adjusted the useful lives of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see Note 4(A) for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019 increased by approximately $16 million.

In 2018, as a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 9(A), the Corporation adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. In addition, on Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2018, increased by approximately $38 million (2017 - $58 million). The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (refer to Note 7 for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2019. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 was shut down two years early, the Canadian Minister of Environment & Climate Change agreed to extend the useful life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the useful life of Sundance Unit 2 to 2021. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017 decreased in total by approximately $4 million. However, in the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment charge for the remaining net book value of the asset (refer to Note 7 for further details).

Wind and Solar

During the third quarter of 2019, the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. Accordingly, depreciation expense for the year ended Dec. 31, 2019 increased by approximately $11 million.

Sheerness

During the second quarter of 2019, the Corporation adjusted the useful life of its Sheerness coal-fired plant assets to align with the dual-fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the year ended Dec. 31, 2019 decreased by approximately $8 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia

During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

TransAlta estimates that the undiscounted amount of cash flow required to settle this additional obligation is approximately $222 million, which will be incurred between 2021 and 2035. The provision may be revised in compliance with the Corporation's accounting policies, dependent upon future operating decisions and as more information becomes available.

B. Comparative Figures

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

4. Significant and Subsequent Events

A. Clean Energy Investment Plan

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017.

TransAlta's plan includes converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. As discussed further below in this section, the Corporation is also advancing permitting to convert one, or possibly two, of its units to highly efficient combined-cycle natural gas units. The highlights of these gas conversion investments include:

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

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

The Corporation's Clean Energy Investment Plan also consists of three wind projects in the United States, one wind project in Alberta and a cogeneration facility. The Big Level and Antrim wind projects began commercial operations on Dec. 19, 2019 and Dec, 24, 2019, respectively. The Skookumchuck and Windrise wind projects are currently under construction. These projects are underpinned by long-term PPAs with highly creditworthy counterparties. In addition, TransAlta is currently constructing a cogeneration facility which will be jointly owned, operated and maintained with SemCAMS.

B. Acquisition of Wind Development Projects

During 2019, TransAlta acquired a portfolio of wind development projects in the US. If the Corporation decides to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025.

C. Agreement to Construct and Own a Cogeneration Plant in Alberta

On Oct. 1, 2019, TransAlta and SemCAMS Midstream ULC ("SemCAMS") announced that they had entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights.

D. TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the 466 MW Genesee 3 facility for Capital Power's 50 per cent ownership interest in the 463 MW Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The transaction price for each non-operating interest largely offset each other, resulting in a net payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

As discussed in Note 3(A)(II), the Corporation early-adopted 2020 amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test. The Corporation elected to apply the optional fair value concentration test to its acquisition of the non-operating interest in Keephills 3, through which it was determined that greater than 90 per cent of the fair value was concentrated in the PP&E acquired. As a result, the acquisition was determined to not be a business and IFRS 3 requirements were not applied and the existing carrying amount of the owned 50 per cent of Keephills 3 was not required to be assessed at fair value. Consequently, the acquisition has been accounted for as an asset acquisition, with the following carrying amounts assigned based on relative fair values:

Working capital	11
Property, plant and equipment	308
Other assets	3
Other liabilities	(2)
Decommissioning and other provisions	(19)
Total acquisition cost	**301**

The sale of Genesee 3 resulted in a gain of $77 million, which was recognized in gains on sale of assets and other on the statement of earnings during the fourth quarter of 2019.

On the closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. The Sunhills mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. On Oct. 1, 2019, upon termination of this agreement, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings in the fourth quarter of 2019.

E. Termination of the Alberta Sundance Power Purchase Arrangements

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective Mar. 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective Mar. 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on Mar. 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation, which the Corporation pursued from the Balancing Pool through an arbitration initiated under the PPAs. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full amount it was seeking to recover of $56 million, plus GST and interest.

F. Strategic Investment by Brookfield

On Mar. 25, 2019, the Corporation announced that it had entered into an agreement (the "Investment Agreement") whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million (the "Investment") in the Corporation. Under the terms of the Investment Agreement, Brookfield agreed to invest $750 million in the Corporation through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA").

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures. See Note 24 for further details.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation, and maximizing the value, of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the operations, maintenance and administration expense on the statements of earnings (loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment (which occurred on May 1, 2019).

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sep. 14, 2020. Refer to Note 35 for further details.

G. Skookumchuck Wind Project

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

H. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater Midstream and Infrastructure Ltd ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. During the fourth quarter of 2019, TransAlta recognized a right-of-use asset and lease liability for the portion of the Pioneer Pipeline that is not directly owned.

During the year ended Dec. 31, 2019, TransAlta invested $83 million in the Pioneer Pipeline and has invested $100 million life-to-date. The Pioneer Pipeline is held in a separate entity that is a joint operation with Tidewater. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation. The Pioneer Pipeline is classified as a joint operation, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations. If these facts and circumstances change, the classification of the joint arrangement may change.

I. Mothballing of Sundance Units

On Mar. 8, 2019, the Corporation announced that the Alberta Electric System Operator ("AESO") granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020. The extensions were requested by TransAlta based on its assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

J. US Wind Projects

On Feb. 20, 2018, TransAlta Renewables Inc. ("TransAlta Renewables") announced it entered into an arrangement to acquire interests in two construction-ready wind projects in the Northeastern United States (collectively, the "US Wind Projects"). The Big Level wind project ("Big Level") consists of a 90 MW wind project located in Pennsylvania that has a 15-year PPA with Microsoft Corp., and the Antrim wind project ("Antrim") consists of a 29 MW wind project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. The Counterparties in the PPAs all have a Standard & Poor's credit ratings of A+ or better.

A subsidiary of TransAlta acquired Big Level on Mar. 1, 2018 and Antrim on Mar. 28, 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in Big Level from a subsidiary of TransAlta Power Ltd. ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns Big Level directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of Big Level. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, the Corporation recognized $50 million for assets under construction in PP&E and $15 million in intangibles. The TransAlta subsidiary also paid the final holdback for the Big Level development project of $7 million (US$5 million) on the closing of Antrim.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs. TransAlta Renewables funded these costs either by acquiring additional tracking preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes were used exclusively in connection with the acquisition and construction of the US Wind Projects.

During 2019, TransAlta Renewables funded the acquisition of Antrim and the construction costs of the US Wind Projects by subscribing for $142 million (US$105 million) of interest-bearing promissory notes and $78 million (US $59 million) of tracking preferred shares.

Big Level and Antrim each began commercial operations in December 2019. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US $85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the Consolidated Statements of Financial Position.

From the tax equity proceeds, a subsidiary of TransAlta repaid $52 million (US$40 million) of the interest-bearing promissory notes from TransAlta Renewables. The remaining amount of the tax equity proceeds is held as reserves within the project entity and will be released upon certain conditions being met. Once these conditions are met, the reserves will be released and the subsidiary of TransAlta will repay the remaining outstanding interest-bearing promissory notes from TransAlta Renewables.

K. Normal Course Issuer Bid

2019

On May 27, 2019, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may purchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million. See Note 26 for further details.

2018

On March 9, 2018, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to such NCIB, the Corporation was permitted to repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.86 per cent of issued and outstanding common shares as at March 2, 2018.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled a total of 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million.

L. Windrise

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the three successful projects in the third round of the Renewable Electricity Program. The Windrise wind project, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately $270 million to $285 million and is targeted to reach commercial operation during the first half of 2021.

M. Kent Hills 3 Wind Project

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

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

N. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

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

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge, of which $11 million was recorded against PP&E and $1 million against intangibles. See Note 7 for further details.

O. TransAlta Renewables Closes $150 Million Offering of Common Shares

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

The net proceeds of the Offering were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility was used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(J) above.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 12 for further details of TransAlta's ownership of TransAlta Renewables.

P. $345 Million Financing Related to the Off-Coal Agreement

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

The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

Q. Early Redemption of $400 Million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest. See Note 23 for further details.

R. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its then outstanding 6.650 per cent US$500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense. See Note 23 for further details.

S. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited

On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidiary of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the facility has not reached commercial operation within a specified time period. FMG is asserting that the South Hedland facility did not achieve commercial operation in accordance with the terms of the South Hedland PPA within the specified time period.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation is taking all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized. The South Hedland facility has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA. This matter is scheduled to proceed to trial beginning June 15, 2020. See also Note 35.

T. Reacquisition of Solomon Facility

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon facility from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon facility on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action in the Supreme Court of Western Australia to recover all, or a significant portion of, this amount from FMG. A trial date for this matter has not yet been scheduled. See also Note 35.

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

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

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million, which included the principal of $191 million, an early redemption premium of $6 million and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

V. Force Majeure Relief – Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool sought to set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. The Court of Queen's Bench dismissed this application. ENMAX and the Balancing Pool are now attempting to appeal that decision in the Court of Appeal, which requires leave (permission) of the Court. The leave application was heard on Nov. 13, 2019. On Feb. 13, 2019, the Alberta Court of Appeal granted the Balancing Pool and ENMAX permission to appeal. The next step is for TransAlta to continue to defend the arbitration award in the appeal application, which will likely be heard in 2020.

W. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was effective on Jan. 1, 2017, and, in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate, effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. In December 2018, TransAlta exercised its option to terminate its land lease agreement, where the Mississauga facility is located, with Boeing Canada Inc. effective Dec. 31, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

The NUG Contract provided the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations. Further details on the NUG Contract and its impact on these financial statements can be found in Note 9(B).

X. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for net proceeds to the Corporation of $61 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and environmental attributes, leasing of power facilities, and from energy marketing and trading activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	395	10	205	87	244	142	—	—	1,083
Revenue from leases[(1)]	65	—	—	65	—	—	—	—	130
Revenue from derivatives	(17)	160	2	—	18	—	129	4	296
Government incentives	—	—	—	—	8	—	—	—	8
Revenue from other[(2)]	373	401	2	8	42	14	—	(10)	830
Total revenue	816	571	209	160	312	156	129	(6)	2,347
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	41	10	—	—	27	—	—	—	78
Over time	354	—	205	87	217	142	—	—	1,005
Total revenue from contracts with customers	395	10	205	87	244	142	—	—	1,083

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(2) Includes merchant revenue and other miscellaneous.

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	517	9	224	91	206	132	—	—	1,179
Revenue from leases[(1)]	68	—	—	68	27	7	—	—	170
Revenue from derivatives	(1)	115	4	—	(20)	—	67	—	165
Government incentives	—	—	—	—	16	—	—	—	16
Revenue from other[(2)]	328	318	4	6	53	17	—	(7)	719
Total revenue	912	442	232	165	282	156	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	38	9	—	—	18	—	—	—	65
Over time	479	—	224	91	188	132	—	—	1,114
Total revenue from contracts with customers	517	9	224	91	206	132	—	—	1,179

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases (2017 - $247 million).
(2) Includes merchant revenue and other miscellaneous.

B. Contract Liabilities

The Corporation has recognized the following revenue-related contract liabilities:

Contract liabilities	**2019**	2018
Balance, beginning of the year	**88**	62
IFRS 16 and 15 transition adjustments[(1)]	**15**	17
Amounts transferred to revenue included in opening balance	**(10)**	(10)
Consideration received	**5**	13
Increases due to interest accrued and expensed during the period	**5**	6
Contract termination associated with the purchase of Keephills 3 (Note 4(D))	**(88)**	—
Balance, end of year	**15**	88
Current portion	**1**	8
Long-term portion	**14**	80

(1) In 2019, on transition to IFRS 16 some contracts that were previously considered leases under IAS 17 did not meet the definition of a lease under IFRS 16 and therefore were assessed under IFRS 15 and balances were transferred from deferred revenue to contract liabilities. In 2018, this adjustment related to the significant financing component added on adoption of IFRS 15.

Contract liabilities in 2018 were primarily comprised of consideration received from the Corporation's Keephills 3 joint operation partner, Capital Power, for which the Corporation had a future obligation to transfer goods and services to Capital Power under the contract. On closing of the Keephills 3 and Genesee 3 swap, wherein the Corporation acquired Capital Power's 50 per cent ownership interest in Keephills 3 and sold its 50 per cent ownership interest in Genesee 3, the agreement with Capital Power was terminated and the Corporation no longer had any further performance obligations and the related contract liability balance was recognized in net earnings.

The remaining contract liabilities outstanding at Dec. 31, 2019, primarily relate to prepayments relating to the Corporation's New Richmond and Bone Creek facilities where the Corporation still has to fulfil its performance obligations.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

Additionally, in many of the Corporation's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Corporation's influence. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved. Further, adjustments to revenue to recognize a significant financing component in a contract are not included in the amounts disclosed for remaining performance obligations.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Corporation from its contractual portfolio.

Canadian Coal

At Dec. 31, 2019, the Corporation has PPAs with the Balancing Pool for capacity and electricity from two of its coal plants, as dispatched, with contract end dates of Dec. 31, 2020. All generation produced is delivered for the benefit of the customer. Certain sources of revenue under one PPA contract are accounted for as a lease and are excluded from these disclosures. Pricing is comprised of multiple components, of both fixed and variable nature, consisting of a capacity payment based on a return of capital, availability payments (from or to the customer) based on the 30-day rolling average pool price and actual availability of the plant as compared to targeted availability specified in the PPAs, recovery of regulatory pass-through costs, and payments for delivery of energy based on the variable cost of producing the energy. Energy-related payments are variable depending on output from the plant, which is dependent upon market demand and the operational ability of the plant. Revenues are generally recognized over time, on a monthly basis. Future revenues that are based upon variable consideration are considered to be fully constrained and are excluded from these disclosures.

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal plants. The contracts range in duration from one to three years. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

The Corporation has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer, under which the Corporation will receive a fixed capacity payment and variable energy payments based on production.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $452 million, of which the Corporation expects to recognize approximately $116 million over the next fiscal year and on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

US Coal

The Corporation's long-term contract for the sale of electricity produced at its US Coal plant is considered a derivative and is designated as an all-in-one hedge. Accordingly, while revenues for electricity delivered to the customer are recognized pursuant to the contractual terms, the revenues are not accounted for under IFRS 15 and the contract has been excluded from any required IFRS 15 disclosures.

The Corporation also has a contract for the sale of byproducts of coal combustion from its US Coal plant. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

Canadian Gas

At Dec. 31, 2019, the Corporation has contracts with customers to deliver energy services from one of its gas plants in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. A summary of the key terms of these contracts is set out below.

The energy supply agreements require specified amounts of steam to be delivered to each customer, and have pricing terms that include fixed and variable charges for electricity, capacity and steam, as well as a true-up based on contractual minimum volumes of steam. The steam reconciliation is based on an estimate of the customer's steam volume taken and the contractual minimum volume, and various factors including the annual average market price of electricity and the average locally posted and index prices of natural gas, as well as transportation. For steam volumes not taken by the customer, a revenue-sharing mechanism provides for sharing of revenues earned by the Corporation using that steam to generate and sell electricity. Capacity and electricity pricing vary from contract to contract and are subject to annual indexation at varying rates. Electricity and steam delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

At the same gas plant, the Corporation has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Corporation's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2019, the Corporation had contracts with customers to deliver steam, hot water and chilled water from one of its other gas plants in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $18 million in total, of which the Corporation expects to recognize between approximately $4 million to $6 million annually for the duration of the contracts.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to some of the Corporation's other gas facilities' contracts in Ontario; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas

At Dec. 31, 2019, the Corporation has PPAs with customers to deliver electricity from its gas plants located in Australia. One contract is considered to be a lease and is excluded from these disclosures. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2021 to 2042.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $2,095 million, of which the Corporation expects to recognize approximately $223 million in total over the next three fiscal years and on average, between approximately $80 million to $110 million annually thereafter for the duration of the contracts.

Wind and Solar

At Dec. 31, 2019, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind farms located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Corporation expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchaser over the remaining terms of the contracts, from 2020 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $8 million, of which the Corporation expects to recognize between approximately $1 million to $2 million annually through to contract expiry.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to wind energy contracts in Ontario, New Brunswick, Quebec and Wyoming, and for all solar contracts; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Hydro

At Dec. 31, 2019, the Corporation has a PPA with the Balancing Pool to provide the capacity of 12 hydro plants throughout the province of Alberta. The capacity payment is fixed on an annual basis. As part of the PPA, the Corporation also has a financial obligation to the Balancing Pool determined on the basis of notional quantities of electricity delivered and the pool price for the period. The Corporation expects to recognize revenue as it makes capacity available to the customer until completion of the contract term at Dec. 31, 2020. The Corporation also has contracts for blackstart services at specific hydro plants, which conclude in 2020, and a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which concludes in 2021.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $72 million, which the Corporation expects to recognize in the next two fiscal years.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to all hydro energy contracts in Ontario, British Columbia and Washington; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2019**		2018		2017	
	Fuel and purchased power	**Operations, maintenance and administration**	Fuel and purchased power	Operations, maintenance and administration	Fuel and purchased power	Operations, maintenance and administration
Fuel[(1)]	**669**	**—**	656	—	685	—
Purchased power	**246**	**—**	210	—	162	—
Mine depreciation	**119**	**—**	136	—	73	—
Salaries and benefits[(1)]	**52**	**228**	98	245	96	248
Other operating expenses	**—**	**247**	—	270	—	269
Total	**1,086**	**475**	1,100	515	1,016	517

(1) $90 million in 2017 was reclassified from fuel to salaries and benefits to be consistent with the 2018 and 2019 classifications.

7. Asset Impairment Charges and Reversals

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

A. 2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia Plant CGU exceeded the carrying value, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test, an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	2016
Mid-Columbia annual average power prices	**US$30 to US$42 per MWh**	US$22 to US$46 per MWh
On-highway diesel fuel on coal shipments	**US$2.35 to US$2.40 per gallon**	US$1.69 to US$2.09 per gallon
Discount rates	**5.2 to 6.4 per cent**	5.4 to 5.7 per cent

During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

Refer to Note 3(A)(IV) and 22 for further details on the Centralia mine decommissioning and restoration provision.

Assets Held for Sale

In the fourth quarter of 2019, the Corporation identified several trucks and associated inventory to be sold within the Canadian Coal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

B. 2018

Sundance Unit 2

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

Lakeswind and Kent Breeze

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 4(N)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately seven per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (refer to Note 17 and 19).

C. 2017

Sundance Unit 1

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

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

D. Project Development Costs

During 2019, the Corporation wrote off $18 million (2018 - $23 million) in project development costs related to projects that are no longer proceeding.

8. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases associated with the Poplar Creek cogeneration facility and in 2018, the Fort Saskatchewan cogeneration facility are as follows:

As at Dec. 31	2019		2018	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**20**	**20**	30	29
Second to fifth years inclusive	**80**	**74**	80	74
More than five years	**120**	**97**	140	112
	220	**191**	250	215
Less: unearned finance lease income	**29**	**—**	35	—
Total finance lease receivables	**191**	**191**	215	215

Included in the Consolidated Statements of Financial Position as:	2019	2018
Current portion of finance lease receivables (Note 13)	**15**	24
Long-term portion of finance lease receivables	**176**	191
	191	215

9. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2019	2018	2017
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Mississauga cogeneration facility NUG Contract	**(1)**	—	(9)
Insurance recoveries	**(10)**	(7)	—
Other expenses	**2**	—	—
Net other operating income	**(49)**	(47)	(49)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The swap of ownership interests in Keephills 3 and Genesee 3 will not impact the payments received. Refer to Note 4(D) for further details.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030. In July 2018, the Corporation obtained financing against the OCA payments. Refer to Note 4(P) and 23 for further details.

B. Mississauga Cogeneration Facility Contract

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

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

In December 2018, TransAlta exercised its option to terminate its land lease agreement for the site with Boeing Canada Inc. effective Jan. 1, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

C. Insurance Recoveries

During 2019, the Corporation received $10 million in insurance recoveries, which related to insurance proceeds for tower fires at Wyoming Wind and Summerview.

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related to insurance proceeds for the tower fire at Wyoming Wind and a $1 million claim related to equipment repairs within Canadian Coal. There were no insurance recoveries in 2017.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2019	2018	2017
Interest on debt	**161**	184	218
Interest on exchangeable securities (Note 24)	**20**	—	—
Interest income	**(13)**	(11)	(7)
Capitalized interest (Note 17)	**(6)**	(2)	(9)
Loss on redemption of bonds (Note 23)	**—**	24	6
Interest on finance lease obligations	**4**	3	3
Credit facility fees, bank charges and other interest	**15**	13	18
Tax shield on tax equity financing (Note 23)(1)	**(35)**	—	—
Other(2)	**10**	15	(3)
Accretion of provisions (Note 22)	**23**	24	21
Net interest expense	**179**	250	247

(1) Relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim wind projects that was assigned to the tax equity investor. The tax equity investment is treated as debt under IFRS and the monetization of the tax depreciation is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.
(2) In 2019, other interest expense included approximately $5 million (2018 - $7 million, 2017 - nil) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable.

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2019	2018	2017
Earnings before income taxes	**193**	(96)	(54)
Net earnings attributable to non-controlling interests not subject to tax	**(26)**	(19)	(35)
Adjusted earnings before income taxes	**167**	(115)	(89)
Statutory Canadian federal and provincial income tax rate (%)	**26.5%**	26.8%	26.8%
Expected income tax expense (recovery)	**44**	(31)	(24)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**5**	(3)	(11)
Writedown (reversal of writedown) of deferred income tax assets	**(9)**	27	(15)
Statutory and other rate differences	**(31)**	—	110
Other	**8**	1	4
Income tax expense (recovery)	**17**	(6)	64
Effective tax rate (%)	**10%**	5%	72%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2019	2018	2017
Current income tax expense[1]	**35**	28	79
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**22**	(61)	(110)
Deferred income tax expense resulting from changes in tax rates or laws[2,3]	**(31)**	—	110
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[4]	**(9)**	27	(15)
Income tax expense (recovery)	**17**	(6)	64

Year ended Dec. 31	2019	2018	2017
Current income tax expense	**35**	28	79
Deferred income tax recovery	**(18)**	(34)	(15)
Income tax expense (recovery)	**17**	(6)	64

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon facility Nov. 1, 2017.

(2) In 2019, the Corporation recognized a deferred income tax recovery of $31 million related to a decrease in the Alberta corporate tax rate from 12 per cent to 8 per cent. The tax decrease is phased in as follows: 11 per cent effective July 1, 2019, 10 per cent effective January 1, 2020, 9 per cent effective January 1, 2021, and 8 per cent effective January 1, 2022.

(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act, which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income.

(4) During the year ended Dec. 31, 2019, the Corporation recorded a reversal of a previous writedown of deferred income tax assets of $9 million (2018 - $27 million writedown, 2017 - $15 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period-end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. The Corporation previously wrote these assets off when it was not considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. Recognized ordinary income and other comprehensive income has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2019	2018	2017
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**6**	(12)	(108)
Net impact related to net investment hedges	**—**	—	(7)
Net actuarial gains (losses)	**(7)**	5	(4)
Income tax expense reported in equity	**(1)**	(7)	(119)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2019	2018
Net operating loss carryforwards	**494**	547
Future decommissioning and restoration costs	**122**	113
Property, plant and equipment	**(828)**	(896)
Risk management assets and liabilities, net	**(141)**	(145)
Employee future benefits and compensation plans	**56**	68
Interest deductible in future periods	**42**	48
Foreign exchange differences on US-denominated debt	**40**	35
Deferred coal revenues	**—**	23
Other deductible temporary differences	**4**	—
Net deferred income tax liability, before writedown of deferred income tax assets	**(211)**	(207)
Writedown of deferred income tax assets	**(243)**	(266)
Net deferred income tax liability, after writedown of deferred income tax assets	**(454)**	(473)

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

As at Dec. 31	2019	2018
Deferred income tax assets(1)	**18**	28
Deferred income tax liabilities	**(472)**	(501)
Net deferred income tax liability	**(454)**	(473)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2019, the Corporation had recognized a net liability of $1 million (2018 - nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2019
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.6% - Public shareholders
Kent Hills Wind LP(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind farm located in New Brunswick.

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

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders may elect to automatically reinvest monthly dividends into additional common shares of the Corporation.

As a result of the conversion of the Class B shares, the DRIP and the Offering described in Note 4(O), the Corporation's share of ownership and equity participation in TransAlta Renewables has changed as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9
Jan. 1, 2019 to Mar. 31, 2019	60.8	60.8
Apr. 1, 2019 to June 30, 2019	60.6	60.6
July 1, 2019 to Sept. 30, 2019	60.5	60.5
Oct. 1, 2019 to Dec. 31, 2019	60.4	60.4

Year ended Dec. 31	2019	2018	2017
Revenues	**446**	462	459
Net earnings	**183**	241	13
Total comprehensive income	**138**	281	(24)
Amounts attributable to the non-controlling interests:			
Net earnings	**73**	94	11
Total comprehensive income	**56**	110	—
Distributions paid to non-controlling interests	**69**	79	85

As at Dec. 31	2019	2018
Current assets	**293**	250
Long-term assets	**3,409**	3,497
Current liabilities	**(152)**	(159)
Long-term liabilities	**(1,237)**	(1,192)
Total equity	**(2,313)**	(2,396)
Equity attributable to non-controlling interests	**(941)**	(961)
Non-controlling interests' share (per cent)	**39.6**	39.1

B. TA Cogen

Year ended Dec. 31	2019	2018	2017
Results of operations			
Revenues	**181**	185	175
Net earnings	**43**	29	61
Total comprehensive income	**43**	29	61
Amounts attributable to the non-controlling interest:			
Net earnings	**21**	14	31
Total comprehensive income	**21**	14	31
Distributions paid to Canadian Power Holdings Inc.	**37**	86	87

As at Dec. 31	2019	2018
Current assets	**41**	82
Long-term assets	**328**	354
Current liabilities	**(27)**	(54)
Long-term liabilities	**(19)**	(28)
Total equity	**(323)**	(354)
Equity attributable to Canadian Power Holdings Inc.	**(160)**	(176)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables

As at Dec. 31	2019	2018
Trade accounts receivable	**399**	597
Promissory note receivable(1)	**—**	25
Collateral paid (Note 15)	**42**	105
Current portion of finance lease receivables (Note 8)	**15**	24
Income taxes receivables	**6**	5
Trade and other receivables	**462**	756

(1) The promissory note receivable relates to funding provided for the Antrim wind project in 2018. Refer to Note 4(J) for further details.

14. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

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

Carrying value as at Dec. 31, 2019

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	–	–	411	411
Restricted cash	–	–	32	32
Trade and other receivables	–	–	462	462
Long-term portion of finance lease receivable	–	–	176	176
Risk management assets				
Current	71	95	–	166
Long-term	607	33	–	640
Other assets (Note 21)	–	–	47	47
Financial liabilities				
Accounts payable and accrued liabilities	–	–	413	413
Dividends payable	–	–	37	37
Risk management liabilities				
Current	1	80	–	81
Long-term	1	28	–	29
Credit facilities, long-term debt and finance lease obligations[2]	–	–	3,212	3,212
Exchangeable securities	–	–	326	326

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

Carrying value as at Dec. 31, 2018

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Total
Financial assets					
Cash and cash equivalents[1]	–	–	89	–	89
Restricted cash	–	–	66	–	66
Trade and other receivables	–	–	731	25	756
Long-term portion of finance lease receivables	–	–	191	–	191
Risk management assets					
Current	60	86	–	–	146
Long-term	629	33	–	–	662
Other assets	–	–	37	15	52
Financial liabilities					
Accounts payable and accrued liabilities	–	–	496	–	496
Dividends payable	–	–	58	–	58
Risk management liabilities					
Current	1	89	–	–	90
Long-term	1	40	–	–	41
Credit facilities, long-term debt and finance lease obligations[2]	–	–	3,267	–	3,267

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

B. Fair Value of Financial Instruments

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

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

I. Level I, II and III Fair Value Measurements

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

a. Level I

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

b. Level II

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

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

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

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

c. Level III

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

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical price relationships.

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

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

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes and shapes.

As at Dec. 31	**2019**		2018	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale – US	**737**	+46 -139	801	+116 -116
Unit contingent power purchases	**(6)**	+1 -1	18	+4 -4
Structured products – Eastern US	**7**	+2 -2	6	+5 -5
Full requirements – Eastern US	**10**	+3 -3	—	—
Long-term wind energy sale – Eastern US	**(28)**	+20 -20	(39)	+21 -21
Others	**—**	+7 -7	9	+3 -3

i. Long-Term Power Sale – US

The Corporation has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2021, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$20 to US$28 (Dec. 31, 2018 - US$20 to US$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US$3 to US$9 (Dec. 31, 2018 - US$6) price decrease or increase in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2018 to Dec. 31, 2019, the base fair value and the sensitivity values have decreased by approximately $11 million and $2 million, respectively.

ii. Unit Contingent Power Purchases

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

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2019, are nil (Dec. 31, 2018 – nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2018 – 2.2 per cent to 16.9 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.0 per cent to 2.0 per cent (Dec. 31, 2018 – 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 10.5 per cent (Dec. 31, 2018 – 8.6 per cent and 27.3 per cent), which approximate one standard deviation for each input.

iii. Structured Products – Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate. As at Dec. 31, 2019, the Corporation did not have any open positions on heat rate contracts.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2019, are 91 per cent to 112 per cent and 63 per cent to 116 per cent (Dec. 31, 2018 – 75 per cent to 109 per cent and 63 per cent to 104 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 4.0 per cent to 6.0 per cent (Dec. 31, 2018 – 4.2 per cent to 6.9 per cent) and a change in non-standard shape factors of approximately 4.0 per cent to 10.0 per cent (Dec. 31, 2018 – 4.0 per cent to 9.3 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. As there are no open positions on Level III heat rate option contracts, the implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2019, are nil and nil (Dec. 31, 2018 – 25 per cent to 84 per cent and 70 per cent), respectively. The sensitivity analysis was prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately nil and nil, respectively (2018 – 37 per cent to 49 per cent and 30 per cent, respectively).

iv. Full Requirements – Eastern US

The Corporation has a portfolio of full requirement service contracts, whereby the Corporation agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits and Independent System Operator costs.

The key unobservable inputs used in the portfolio valuation include delivered volume and supply cost. Hourly shaping of consumption will result in a realized cost that may be at a premium (or discount) relative to the average settled price. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement. The sensitivity analysis has been prepared using the Corporation's assessment that a reasonably possible change in the expected portfolio delivery volumes and portfolio's realized cost of supply of (+/-) 5 per cent and (+/-) US$1 per MWh, respectively.

v. Long-Term Wind Energy Sale – Eastern US

In relation to the acquisition of Big Level (See Note 4(J)), the Corporation has a long-term contract for differences whereby the Corporation receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2024 and 2022, respectively. Forward power and REC prices per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$38 to US$60 and US$9 (Dec. 31, 2018 – US$42 to US $68 and US$7 to US$8), respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent (2018 – 10 per cent), a change in energy prices of US $6 (2018 – US$6) and a change in REC prices of US$1 (2018 – US$1) as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2019, are as follows: Level I - $3 million net liability (Dec. 31, 2018 – $3 million net asset), Level II – $9 million net asset (Dec. 31, 2018 – $19 million net liability) and Level III – $686 million net asset (Dec. 31, 2018 – $695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2019, are primarily attributable to the settlement of contracts and unfavourable foreign exchange rates, partially offset by favourable market prices.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2019 and 2018, respectively:

	Year ended Dec. 31, 2019			Year ended Dec. 31, 2018		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**689**	**6**	**695**	719	52	771
Changes attributable to:						
Market price changes on existing contracts	**77**	**8**	**85**	(7)	(9)	(16)
Market price changes on new contracts	**—**	**14**	**14**	—	4	4
Contracts settled	**(57)**	**(19)**	**(76)**	(90)	(42)	(132)
Change in foreign exchange rates	**(31)**	**(1)**	**(32)**	67	5	72
Transfers into (out of) Level III	**—**	**—**	**—**	—	(4)	(4)
Net risk management assets at end of period	**678**	**8**	**686**	689	6	695
Additional Level III information:						
Gains recognized in other comprehensive income	**46**	**—**	**46**	60	—	60
Total gains included in earnings before income taxes	**57**	**21**	**78**	90	—	90
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**2**	**2**	—	(42)	(42)

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net asset fair value of $4 million as at Dec. 31, 2019 (Dec. 31, 2018 – $2 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2019, are primarily attributable to favourable market prices on existing contracts.

IV. Other Financial Assets and Liabilities

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

	Fair value[1]				Total carrying
	Level I	Level II	Level III	Total	value[1]
Exchangeable securities - Dec. 31, 2019	**—**	**342**	**—**	**342**	**326**
Long-term debt - Dec. 31, 2019	**—**	**3,157**	**—**	**3,157**	**3,070**
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

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

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 21) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	**2019**	2018	2017
Unamortized net gain at beginning of year	**49**	105	148
New inception gains (losses)	**3**	(14)	12
Change in foreign exchange rates	**—**	5	(7)
Amortization recorded in net earnings during the year	**(43)**	(47)	(48)
Unamortized net gain at end of year	**9**	49	105

15. Risk Management Activities

A. Risk Management Strategy

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: i) financial exposure management and ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges, and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

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

As at Dec. 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	70	15	85
Long-term	606	1	607
Net commodity risk management assets	676	16	692
Other			
Current	—	—	—
Long-term	—	4	4
Net other risk management assets	—	4	4
Total net risk management assets	676	20	696

As at Dec. 31, 2018	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	59	–	59
Long-term	628	(8)	620
Net commodity risk management assets (liabilities)	687	(8)	679
Other			
Current	–	(3)	(3)
Long-term	–	1	1
Net other risk management liabilities	–	(2)	(2)
Total net risk management assets (liabilities)	687	(10)	677

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	2019				2018			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**316**	**631**	**(191)**	**(100)**	224	657	(116)	(42)
Gross amounts set-off	**(140)**	**(42)**	**140**	**42**	(53)	(6)	53	6
Net amounts as included in the Consolidated Statements of Financial Position	**176**	**589**	**(51)**	**(58)**	171	651	(63)	(36)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

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

To mitigate the risk of adverse commodity price changes, the Corporation uses three tools:

- A framework of risk controls;
- A pre-defined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Corporation has executed commodity price hedges for its Centralia coal plant and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Corporation's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Corporation's exposure to market risks or the manner in which these risks are managed or measured.

i. Commodity Price Risk Management – Proprietary Trading

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

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2019, associated with the Corporation's proprietary trading activities was $1 million (2018 - $2 million, 2017 - $5 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $25 million (2018 - $18 million, 2017 - $16 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2019, associated with these transactions was $8 million (2018 - $13 million, 2017 - $5 million).

iii. Commodity Price Risk Management – Hedges

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

As at Dec. 31	**2019**		2018	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**222**	**—**	2,128	—

During 2019, unrealized pre-tax gains of $1 million (2018 - $4 million, 2017 - $2 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management – Non-Hedges

The Corporation's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2019		2018	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**16,097**	**7,204**	58,885	37,023
Natural gas *(GJ)*	**38,062**	**55,023**	80,413	110,488
Transmission *(MWh)*	**—**	**1,818**	29	11,163
Emissions *(MWh)*	**184**	**138**	—	—
Emissions *(tonnes)*	**2,436**	**2,446**	3,134	2,948

b. Interest Rate Risk Management

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

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represents 11 per cent of the Corporation's debt as at Dec. 31, 2019 (2018 – 14 per cent).

Interest rate risk is managed with the use of derivatives. No derivatives related to interest rate risk were outstanding as at Dec. 31, 2019, 2018 or 2017.

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Corporation may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Corporation's net investment in foreign subsidiaries, the Corporation has determined that the hedge is effective as the foreign currency of the net investment is the same as the currency of the hedge, and therefore an economic relationship is present.

The Corporation's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$370 million (2018 - US$400 million).

ii. Cash Flow Hedges

The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31	2019			2018			
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
CAD124	**USD95**	**—**	**2020-2021**	—	—	—	—

iii. Non-Hedges

As part of the sale of the Corporation's economic interest in the Australian Assets to TransAlta Renewables, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in the USD and AUD in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program.

The Corporation also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	2019			2018			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures							
AUD286	**CAD266**	**—**	**2020 - 2023**	AUD218	CAD205	(5)	2019-2022
USD108	**CAD139**	**(4)**	**2020 - 2023**	USD164	CAD214	(7)	2019-2022
Foreign exchange forward contracts – foreign-denominated debt							
CAD191	**USD150**	**6**	**2022**	CAD124	USD100	10	2022

iv. Impacts of currency rate risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cent (2018 and 2017 - four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2019		2018		2017	
Currency	**Net earnings increase (decrease)**[1]	**OCI gain**[1],[2]	Net earnings increase[1]	OCI gain[1],[2]	Net earnings decrease[1]	OCI gain[1],[2]
USD	**(18)**	**2**	(13)	—	(5)	—
AUD	**(6)**	**—**	(7)	—	(7)	—
Total	**(24)**	**2**	(20)	—	(12)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2019:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	85	15	**100**	**462**
Long-term finance lease receivable	100	—	**100**	**176**
Risk management assets[1]	99	1	**100**	**806**
Loan receivable[2]	—	100	**100**	**47**
Total				**1,491**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparty has no external credit rating. Refer to Note 21 for further details.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on historical rates of default by segment of trade receivables as well as forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2019.

The Corporation's maximum exposure to credit risk at Dec. 31, 2019, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2019, was $5 million (2018 - $13 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. As at Dec. 31, 2019, TransAlta maintains investment grade ratings from one credit rating agency and below investment grade ratings from three credit rating agencies. Between 2020 and 2022, the Corporation has approximately $1,217 million of debt maturing, comprised of approximately $920 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022. Refer to Note 4(F) and 24 for further details.

Collateral is posted based on negotiated terms with counterparties, which can include the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Board; and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Corporation does not use derivatives or hedge accounting to manage liquidity risk.

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

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Accounts payable and accrued liabilities	413	—	—	—	—	—	413
Long-term debt[1]	494	98	625	372	105	1,410	3,104
Exchangeable securities[2]	—	—	—	—	—	350	350
Commodity risk management assets	(89)	(89)	(143)	(139)	(135)	(97)	(692)
Other risk management (assets) liabilities	1	—	(6)	2	—	(1)	(4)
Lease obligations	19	14	9	6	4	90	142
Interest on long-term debt and lease obligations[3]	161	138	128	98	87	671	1,283
Interest on exchangeable securities[2, 3]	25	25	25	24	24	—	123
Dividends payable	37	—	—	—	—	—	37
Total	**1,061**	**186**	**638**	**363**	**85**	**2,423**	**4,756**

(1) Excludes impact of hedge accounting.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Refer to Note 24 for further details.
(3) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. Total Return Swaps

The Corporation has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2020	2021	2022	2023	2024	2025 and thereafter
Cash flow hedges						
Foreign Currency Forward Contracts						
Notional amount ($ millions)						
CAD/USD	116	8	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7672	0.7686	—	—	—	—
Commodity Derivative Instruments						
Electricity						
Notional amount (thousands MWh)	3,465	3,424	3,329	3,329	3,338	2,628
Average Price ($ per MWh)	67.82	71.06	73.55	75.39	77.28	79.20

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2019	**Notional amount**	**Carrying amount**	**Line item in the statement of financial position**	**Change in fair value used for measuring ineffectiveness**
Commodity price risk				
Cash flow hedges				
Physical power sales	**19 MMWh**	**678**	**Risk management assets**	**47**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD483**	**Credit facilities, long-term debt and finance lease obligations**	**21**

As at Dec. 31, 2018	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	23 MMWh	687	Risk management assets	60
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD400	CAD546	Credit facilities, long-term debt and finance lease obligations	(41)

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31, 2019	**2019**		2018	
	Change in fair value used for measuring ineffectiveness	**Cash flow hedge reserve(1)**	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve(1)
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**47**	**527**	60	508

	Change in fair value used for measuring ineffectiveness	**Foreign currency translation reserve(1)**	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve(1)
Net investment hedges				
Net investment in foreign subsidiaries	**21**	**(21)**	(41)	17

(1) Included in AOCI

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness. There is no ineffectiveness recognized in profit or loss.

The impact of hedged items designated in hedging relationships on OCI and net earnings is:

	Year ended Dec. 31, 2019				
		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	77	Revenue	(59)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	**77**	**OCI impact**	**(53)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $68 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

	Year ended Dec. 31, 2018				
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(9)	Revenue	(67)	Revenue	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	(9)	OCI impact	(57)	Net earnings impact	—

	Year ended Dec. 31, 2017 (as reported under IAS 39)				
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	163	Revenue	(172)	Revenue	—
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Cross-currency swaps	(26)	Foreign exchange (gain) loss	24	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	136	OCI impact	(138)	Net earnings impact	—

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminated the contract effective Jan. 1, 2017. Accordingly, in 2017 the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 9(B) for further details.

II. Effect of Non-Hedges

For the year ended Dec. 31, 2019, the Corporation recognized a net unrealized gain of $33 million (2018 - loss of $29 million, 2017 - gain of $45 million) related to commodity derivatives.

For the year ended Dec. 31, 2019, a gain of $24 million (2018 - gain of $3 million, 2017 - gain of $28 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized gains of $6 million (2018 - gains of $4 million, 2017 - losses of $2 million) and net realized gains of $18 million (2018 - losses of $1 million, 2017 - gains of $30 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2019, the Corporation provided $42 million (2018 – $105 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2019, the Corporation held $3 million (2018 – $17 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation’s senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation’s derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

As at Dec. 31, 2019, the Corporation had posted collateral of $112 million (Dec. 31, 2018 – $120 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $51 million (Dec. 31, 2018 – $120 million) of collateral to its counterparties.

16. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2019	2018
Parts and materials	**108**	113
Coal	**130**	108
Deferred stripping costs	**6**	7
Natural gas	**3**	4
Purchased emission credits	**4**	10
Total	**251**	242

The change in inventory is as follows:

Balance, Dec. 31, 2017	219
Net addition	20
Change in foreign exchange rates	3
Balance, Dec. 31, 2018	242
Net addition	**12**
Change in foreign exchange rates	**(3)**
Balance, Dec. 31, 2019	**251**

No inventory is pledged as security for liabilities.

17. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2017	95	5,888	1,982	3,228	1,315	95	370	12,973
Additions[2]	—	—	—	1	—	275	8	284
Additions - finance lease	—	—	—	—	10	—	—	10
Disposals	(3)	—	—	—	(1)	—	(3)	(7)
Impairment charge (Note 7)	—	(38)	—	(11)	—	—	—	(49)
Revisions and additions to decommissioning and restoration costs	—	(12)	(1)	(3)	(16)	—	—	(32)
Retirement of assets	—	(47)	(17)	(6)	(16)	—	(4)	(90)
Change in foreign exchange rates	2	105	(13)	26	7	4	—	131
Transfers	—	41	13	51	39	(174)	12	(18)
As at Dec. 31, 2018	94	5,937	1,964	3,286	1,338	200	383	13,202
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(7)**	**(101)**	**—**	**—**	**(108)**
Additions[4]	**—**	**—**	**—**	**—**	**—**	**407**	**115**	**522**
Acquisitions (Note 4(D) and 4(J))[5]	**—**	**300**	**—**	**—**	**—**	**139**	**—**	**439**
Disposals[6]	**(2)**	**(389)**	**(260)**	**—**	**(34)**	**—**	**(19)**	**(704)**
Impairment (charges) reversals (Note 7)	**—**	**448**	**—**	**(2)**	**(15)**	**—**	**—**	**431**
Revisions and additions to decommissioning and restoration costs	**—**	**(62)**	**11**	**2**	**26**	**—**	**—**	**(23)**
Retirement of assets	**—**	**(158)**	**(26)**	**(7)**	**(10)**	**—**	**—**	**(201)**
Change in foreign exchange rates	**(1)**	**(63)**	**(40)**	**(17)**	**(3)**	**(4)**	**(6)**	**(134)**
Transfers[7]	**—**	**103**	**22**	**319**	**25**	**(514)**	**16**	**(29)**
As at Dec. 31, 2019	**91**	**6,116**	**1,671**	**3,574**	**1,226**	**228**	**489**	**13,395**
Accumulated depreciation								
As at Dec. 31, 2017	—	3,431	1,072	1,037	713	—	142	6,395
Depreciation	—	306	79	123	125	—	16	649
Retirement of assets	—	(56)	(13)	(2)	(12)	—	—	(83)
Disposals	—	—	—	—	(1)	—	(4)	(5)
Change in foreign exchange rates	—	84	(3)	6	5	—	—	92
Transfers	—	—	(7)	(3)	—	—	—	(10)
As at Dec. 31, 2018	—	3,765	1,128	1,161	830	—	154	7,038
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(3)**	**(43)**	**—**	**—**	**(46)**
Depreciation	**—**	**304**	**77**	**136**	**97**	**—**	**16**	**630**
Retirement of assets	**—**	**(158)**	**(23)**	**(3)**	**(6)**	**—**	**—**	**(190)**
Disposals[5]	**—**	**(170)**	**(255)**	**—**	**(14)**	**—**	**—**	**(439)**
Impairment reversal (Note 7)	**—**	**297**	**—**	**—**	**—**	**—**	**—**	**297**
Change in foreign exchange rates	**—**	**(52)**	**(16)**	**(4)**	**(2)**	**—**	**(2)**	**(76)**
Transfers	**—**	**10**	**(11)**	**(3)**	**(22)**	**—**	**—**	**(26)**
As at Dec. 31, 2019	**—**	**3,996**	**900**	**1,284**	**840**	**—**	**168**	**7,188**
Carrying amount								
As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
As at Dec. 31, 2019	**91**	**2,120**	**771**	**2,290**	**386**	**228**	**321**	**6,207**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance, and the Australian gas pipeline.
(2) Includes $7 million related to the acquisition of Big Level.
(3) Includes net $33 million transferred to right of use assets and $29 million of finance lease assets that were derecognized on implementation of IFRS 16. Refer to Note 3 for further details.
(4) Includes cash additions of $417 million (including $169 million related to the construction of the US Wind Projects), $100 million related to the Pioneer Pipeline (including $15 million transferred from other assets) and $5 million related to the Keephills 3 and Genesee 3 asset swap. Refer to Note 4 for further details of these transactions.
(5) Includes $308 million related to the acquisition of the Keephills 3 facility with $300 million included in coal generation and the remainder in assets under construction.
(6) In 2019, we sold the Genesee 3 facility and sold the major components of the Mississauga facility. In addition, Centralia sold boiler parts included in capital spares and other for a net loss of $17 million. The Sunhills mine also sold trucks included in mining property and equipment for a net loss of $18 million. Both were recognized in other gains on the statement of earnings (loss).
(7) Mainly relates to transferring the Pioneer Pipeline and US Wind Projects from assets under construction to coal generation and renewable generation, respectively.

The Corporation capitalized $6 million of interest to PP&E in 2019 (2018 - $2 million) at a weighted average rate of 5.9 per cent (2018 – 4.5 per cent). Finance lease additions in 2018 were for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2019, was nil as these were transferred to right of use assets on implementation of IFRS 16 (2018 - $65 million).

18. Right of Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right of use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Pipeline	Total
New leases recognized Jan. 1, 2019	29	22	1	—	—	52
Adjustments on recognition[(1)]	(1)	(4)	—	—	—	(5)
Transfers from PP&E, intangibles and other assets	—	—	3	35	—	38
As at Jan. 1, 2019	28	18	4	35	—	85
Additions	32	2	—	2	45	81
Depreciation	(1)	(4)	(2)	(11)	—	(18)
Change in foreign exchange rates	(1)	—	—	—	—	(1)
Transfers	—	—	—	(1)	—	(1)
As at Dec. 31, 2019	58	16	2	25	45	146

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

In November 2019, the Corporation recognized a right of use asset and corresponding lease liability related to the initial 15-year term of its contract for transporting natural gas on the Pioneer Pipeline. The transportation contract provides the Corporation with the right to extend the contract for up to eight additional renewal periods of 24-months each. The amounts recognized represent the 50 per cent of the pipeline that is not owned by the Corporation.

In December 2019, the Corporation recognized an additional $31 million of right of use assets and $31 million of lease liabilities for land leases at certain wind farms as a result of revised interpretations of the unit of account / identified asset concepts present in IFRS 16.

For the year ended Dec. 31, 2019, TransAlta paid $25 million related to recognized lease liabilities, consisting of $4 million in interest and $21 million in principal repayments.

For the year ended Dec. 31, 2019, the Corporation expensed $2 million related to short-term and $1 million related to low value leases. Short term leases (term of less than 12 months) and leases with total lease payments below the Corporation's capitalization threshold do not require recognition as lease liabilities and right of use assets.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2019, the Corporation expensed $6 million in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 10, 15, 23 and 35.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2017	178	314	223	29	744
Additions(1)	—	—	—	53	53
Retirements and disposals(2)	—	(2)	—	—	(2)
Change in foreign exchange rates	—	3	—	—	3
Transfers	7	24	14	(36)	9
As at Dec. 31, 2018	185	339	237	46	807
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(5)**	**—**	**—**	**(5)**
Additions	**—**	**—**	**—**	**14**	**14**
Acquisition	**—**	**1**	**—**	**15**	**16**
Disposals (Note 4(D))	**(37)**	**(1)**	**—**	**—**	**(38)**
Change in foreign exchange rates	**—**	**(4)**	**(1)**	**(1)**	**(6)**
Transfers	**1**	**48**	**14**	**(63)**	**—**
As at Dec. 31, 2019	**149**	**378**	**250**	**11**	**788**
Accumulated amortization					
As at Dec. 31, 2017	125	188	67	—	380
Amortization	9	32	9	—	50
Retirements and disposals	—	(1)	—	—	(1)
Change in foreign exchange rates	—	2	—	—	2
Transfers	(17)	—	20	—	3
As at Dec. 31, 2018	117	221	96	—	434
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(3)**	**—**	**—**	**(3)**
Amortization	**8**	**31**	**11**	**—**	**50**
Disposals (Note 4(D))	**(9)**	**(1)**	**—**	**—**	**(10)**
Change in foreign exchange rates	**—**	**(1)**	**—**	**—**	**(1)**
Transfers	**1**	**(1)**	**—**	**—**	**—**
As at Dec. 31, 2019	**117**	**246**	**107**	**—**	**470**
Carrying amount					
As at Dec. 31, 2017	53	126	156	29	364
As at Dec. 31, 2018	68	118	141	46	373
As at Dec. 31, 2019	**32**	**132**	**143**	**11**	**318**

(1) Includes $33 million related to the acquisition of Big Level.
(2) Includes the impairment charge of $1 million relating to Kent Breeze. See Note 7 for further details.

20. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	2019	2018
Hydro	**258**	259
Wind and Solar	**176**	175
Energy Marketing	**30**	30
Total goodwill	**464**	464

For the purposes of the 2019 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Hydro, Wind and Solar, and Energy Marketing segments by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2019 models ranged between $5 to $183 per MWh during the forecast period (2018 – $6 to $179 per MWh). Discount rates used for the goodwill impairment calculation in 2019 ranged from 3.6 per cent to 7.0 per cent (2018 – 5.3 per cent to 6.6 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

21. Other Assets

The components of other assets are as follows:

As at Dec. 31	2019	2018
South Hedland prepaid transmission access and distribution costs	**67**	72
Deferred licence fees	**9**	11
Project development costs	**19**	47
Deferred service costs	**—**	12
Long-term prepaids and other assets	**56**	55
Loan receivable	**47**	37
Total other assets	**198**	234

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

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

Project development costs include the project costs for Windrise (Note 4(L)) and the US wind development projects (Note 4(B)). Some projects were written off in 2019 and 2018 as they are no longer proceeding (see Note 7(D)).

Deferred service costs related to TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. As part of the Genesee Unit 3 and Keephills Unit 3 swap, these assets were included in the transaction (Note 4(D)).

Long-term prepaids and other assets includes: the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 35(F), the Keephills Unit 3 provincially required transmission deposit which is anticipated to be reimbursed over the next two years to 2021, as long as certain performance criteria are met, and other miscellaneous prepaids and deposits.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $47 million (2018 – $37 million) (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022.

22. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2017	437	33	470
Liabilities incurred	5	17	22
Liabilities settled	(31)	(10)	(41)
Accretion	24	—	24
Acquisition of liabilities (Big Level)	—	8	8
Revisions in estimated cash flows	2	3	5
Revisions in discount rates	(37)	—	(37)
Reversals	—	(5)	(5)
Change in foreign exchange rates	7	3	10
Balance, Dec. 31, 2018	407	49	456
IFRS 16 transition adjustment	**—**	**(2)**	**(2)**
Liabilities incurred	**7**	**7**	**14**
Liabilities settled	**(34)**	**(9)**	**(43)**
Accretion	**23**	**—**	**23**
Acquisition of liabilities	**16**	**3**	**19**
Disposition of liabilities	**(23)**	**(9)**	**(32)**
Revisions in estimated cash flows[(1)]	**96**	**7**	**103**
Revisions in discount rates	**16**	**—**	**16**
Reversals	**—**	**(1)**	**(1)**
Change in foreign exchange rates	**(7)**	**—**	**(7)**
Balance, Dec. 31, 2019	**501**	**45**	**546**

(1) During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. Refer to Note 3(A)(III) for further details. In addition, due to the changes in estimated useful lives, described in Note 3(A)(IV), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed. The use of a lower inflation rate decreased the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2018	407	49	456
Current portion	35	35	70
Non-current portion	372	14	386
Balance, Dec. 31, 2019	**501**	**45**	**546**
Current portion	**36**	**22**	**58**
Non-current portion	**465**	**23**	**488**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.3 billion, which will be incurred between 2020 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2019, the Corporation had provided a surety bond in the amount of US$147 million (2018 – US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2019, the Corporation had provided letters of credit in the amount of $128 million (2018 – $122 million) in support of future decommissioning obligations at the Alberta mine.

B. Other Provisions

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

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

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	**2019**			2018		
	Carrying value	**Face value**	**Interest**(1)	Carrying value	Face value	Interest(1)
Credit facilities(2)	**220**	**220**	**3.5%**	339	339	3.8%
Debentures	**647**	**651**	**5.8%**	647	651	5.8%
Senior notes(3)	**905**	**914**	**5.4%**	943	955	5.4%
Non-recourse(4)	**1,144**	**1,157**	**4.3%**	1,236	1,250	4.4%
Other(5)	**154**	**162**	**7.1%**	39	39	9.2%
	3,070	**3,104**		3,204	3,234	
Finance lease obligations	**142**			63		
	3,212			3,267		
Less: current portion of long-term debt	**(494)**			(130)		
Less: current portion of finance lease obligations	**(19)**			(18)		
Total current long-term debt and finance lease obligations	**(513)**			(148)		
Total credit facilities, long-term debt and finance lease obligations	**2,699**			3,119		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2019 - US$0.7 billion (Dec. 31, 2018 - US$0.7 billion).
(4) Includes US$1 million at Dec. 31, 2019 (Dec. 31, 2018 - US$1 million).
(5) Includes US$117 at Dec. 31, 2019 (Dec. 31, 2018 - US$21 million) of tax equity financing.

Our credit facilities include the Corporation's $1.3 billion committed syndicated bank credit facility expiring in 2023, TransAlta Renewable's $700 million committed syndicated bank credit facility expiring in 2023 and the Corporation's three bilateral credit facilities totalling $240 million expiring in 2021. The $2.0 billion (Dec. 31, 2018 – $1.8 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, US LIBOR, or US base rate – in accordance with a pricing grid that is standard for such facilities.

During 2019, the Corporation renewed these credit facilities and TransAlta Renewables' facility was increased by $200 million to $700 million.

During 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

The Corporation has a total of $2.2 billion (Dec. 31, 2018 – $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $0.7 billion (Dec. 31, 2018 – $0.5 billion). In total, $1.3 billion (Dec. 31, 2018 – $0.9 billion) is not drawn. At Dec. 31, 2019, the $0.9 billion (Dec. 31, 2018 – $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $220 million (Dec. 31, 2018 – $339 million) and letters of credit of $690 million (Dec. 31, 2018 – $720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, the Corporation also has $411 million of available cash and cash equivalents and $17 million ($10 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030.

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040.

During 2018, the Corporation early redeemed its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross-currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

During 2017, the Corporation's US$400 million 1.90 per cent senior note matured and was paid out using existing liquidity. The repayment was hedged with a currency swap. The maturity value of the bond was $434 million.

A total of US$370 million (2018 - US$400 million) of the senior notes has been designated as a hedge of the Corporation’s net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 6.03 per cent.

During 2018, the Corporation:

- Paid out the US$25 million non-recourse debt related to its Mass Solar projects.
- Monetized the OCA and closed a $345 million bond offering through its indirect wholly owned subsidiary TransAlta OCP by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financings related to Big Level and Antrim of $122 million and Lakeswind of $23 million.

During 2019, coinciding with Antrim and Big Level each achieving commercial operation, TransAlta received tax equity funding of approximately US$41 million and US$85 million, respectively. Refer to Note 4(J) for further details.

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind acquired tax equity which was initially recognized at its fair value. Tax equity financing balances are reduced by the value of tax benefits (production tax credits and tax depreciation) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. In 2019, the Big Level and Antrim wind projects claimed accelerated (bonus) tax depreciation of $35 million in total, which was allocated to the tax equity investor, and had the effect of reducing the tax equity financing balance. The maturity dates of each financing are subject to change and primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Corporation anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim - in December 2029, 10 years from commercial operation of the projects; and Lakeswind - March 31, 2024.

TransAlta’s debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2019, the Corporation was in compliance with all debt covenants.

B. Restrictions related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and TransAlta OCP non-recourse bonds with a carrying value of $1,143 million as at Dec. 31, 2019 (Dec. 31, 2018 - $1,235 million) are subject to customary financing conditions and covenants that may restrict the Corporation’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2019. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2020. At Dec. 31, 2019, $42 million (Dec. 31, 2018 – $33 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2019.

Proceeds received from the Big Level and Antrim tax equity financing in the amount of $91 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying outstanding project development costs.

C. Security

Non-recourse debts totalling $719 million as at Dec. 31, 2019 (Dec. 31, 2018 – $766 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which include property, plant and equipment with total carrying amounts of $967 million at Dec. 31, 2019 (Dec. 31, 2018 – $1,021 million) and intangible assets with total carrying amounts of $63 million (Dec. 31, 2018 – $70 million). At Dec. 31, 2019, a non-recourse bond of approximately $119 million (Dec. 31, 2018 – $127 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds have a carrying value of $305 million (Dec. 31, 2018 – $342 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

D. Principal Repayments

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Principal repayments[1]	494	98	625	372	105	1,410	3,104
Lease obligations	19	14	9	6	4	90	142

(1) Excludes impact of derivatives.

E. Restricted Cash

At Dec. 31, 2019, the Corporation had $15 million in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in the first half of 2020.

The Corporation also had $17 million (Dec. 31, 2018 – $35 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2020. The Corporation had nil (Dec. 31, 2018 – $31 million) restricted cash related to the Kent Hills project financing.

F. Letters of Credit

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

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2019 was $690 million (2018 – $720 million) with no (2018 – nil) amounts exercised by third parties under these arrangements.

24. Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into an Investment Agreement whereby Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA ("Option to Exchange"). On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions.

A. $350 Million Unsecured Subordinated Debentures

As at	Dec. 31, 2019		
	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	326	350	7%

If Brookfield chooses not to exercise its Option to Exchange as outlined below, TransAlta has the right after Dec. 31, 2028 to redeem for cash all or any portion of the Exchangeable Securities for the original subscription price, plus any accrued but unpaid interest or dividends payable, provided the minimum proceeds to Brookfield for each redemption (other than the final redemption) is not less than $100 million and provided all Exchangeable Securities must be redeemed within 36 months of the first optional redemption.

B. Option to Exchange

As at	Dec. 31, 2019	
Description	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	+35 -27

The Investment Agreement allows Brookfield the Option to Exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the Option to Exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the Option to Exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, and provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Hydro Assets, provided the 20-day volume-weighted average price ("VWAP") of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the Investment would exceed a 49 equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

25. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2019	2018
Defined benefit obligation (Note 30)	**268**	227
Long-term incentive accruals (Note 29)	**4**	9
Other	**29**	51
Total	**301**	287

26. Common Shares

A. Issued and Outstanding

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

As at Dec. 31	2019		2018	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**284.6**	**3,059**	287.9	3,094
Purchased and cancelled under the NCIB	**(7.7)**	**(83)**	(3.3)	(35)
Stock options exercised	**0.1**	**2**	—	—
Issued and outstanding, end of year	**277.0**	**2,978**	284.6	3,059

B. NCIB Program

Shares purchased by the Corporation under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in deficit.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31	2019	2018
Total shares purchased(1)	**7,716,300**	3,264,500
Average purchase price per share	**$ 8.80**	$ 7.02
Total cost	**68**	23
Weighted average book value of shares cancelled	**83**	35
Amount recorded in deficit	**15**	12

(1) As at Dec. 31, 2019, includes 189,900 (2018 - 204,000) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019 to reflect current market practice and to reflect changes to the take-over bid regime. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 26, 2019. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Corporation's common shares, except in limited circumstances including by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	2019	2018	2017
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Basic and diluted weighted average number of common shares outstanding (millions)	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.86)	(0.66)

E. Dividends

On Oct. 9, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2020. On Jan. 16, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Apr. 1, 2020.

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

27. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	2019		2018	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series G Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Aug. 30, 2019, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2019, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (the "Series G Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series H (the "Series H Shares"), there were 140,730 Series G Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series H Shares. Therefore, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2019. As a result, the Series G Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series G Shares for the five-year period from and including Sept. 30, 2019, to, but excluding, Sept. 30, 2024, will be 4.988 per cent, which is equal to the five-year Government of Canada bond yield of 1.188 per cent, determined as of Aug. 30, 2019, plus 3.80 per cent, in accordance with the terms of the Series G Shares.

II. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

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

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

IV. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion
On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation had 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2019.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on the 90-day Treasury Bill rate plus 2.03 per cent.

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

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

Characteristics specific to each first preferred share series as at Dec. 31, 2019, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.67725	March 31, 2021	2.03	B
B	Floating	0.93575	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29850	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.32500	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of preferred share dividends declared in 2019, 2018 and 2017:

	Total dividends declared		
Series	**2019**	2018	2017
A	**5**	9	5
B	**1**	1	1
C	**8**	14	9
E	**9**	15	8
G	**7**	11	7
Total for the year	**30**	50	30

28. Accumulated Other Comprehensive Income

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

	2019	2018
Currency translation adjustment		
Opening balance, Jan. 1	**17**	(26)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(59)**	84
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**21**	(41)
Balance, Dec. 31	**(21)**	17
Cash flow hedges		
Opening balance, Jan. 1	**508**	562
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[1]	**19**	(54)
Balance, Dec. 31	**527**	508
Employee future benefits		
Opening balance, Jan. 1	**(29)**	(44)
Net actuarial gains (losses) on defined benefit plans, net of tax[2]	**(26)**	15
Balance, Dec. 31	**(55)**	(29)
Other		
Opening balance, Jan. 1	**(15)**	(3)
Change in ownership of TransAlta Renewables	**1**	4
Intercompany investments at FVOCI	**17**	(16)
Balance, Dec. 31	**3**	(15)
Accumulated other comprehensive income	**454**	481

(1) Net of income tax of $6 million for the year ended Dec. 31, 2019 (2018 - $12 million).
(2) Net of income tax of $7 million for the year ended Dec. 31, 2019 (2018 - $5 million).

29. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit (“PSU”) and Restricted Share Unit (“RSU”) Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants’ base pay and are converted to PSUs or RSUs on the basis of the Corporation’s common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation’s share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation’s common shares.

During 2019, as a result of the Corporation's change in its intended settlement policy, the accounting classification of the RSUs and PSUs changed from cash-settled to equity-settled. The RSUs and PSUs have been accounted for as equity-settled grants from the dates of the policy change, with fair values determined as at that date. On average, the fair value of outstanding grants used in accounting for the change was $8.29, measured using the black-scholes option pricing model. As a result of this change, the liability for the cash-settled grants ($25 million) has been derecognized and the equity-settled fair value ($24 million) has been recognized in contributed surplus, with the net difference of $1 million representing the cumulative change in compensation expense. No changes were made to the vesting or performance conditions associated with the awards. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expenses related to this plan are recognized during the period earned, with the corresponding amounts due under the plan recorded in contributed surplus (2018 - liabilities). Prior to this change, the liability was valued at the end of each reporting period using the closing price of the Corporation’s common shares on the TSX.

The pre-tax compensation expense related to PSUs and RSUs in 2019 was $19 million (2018 - $8 million, 2017 - $15 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit (“DSU”) Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation’s common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation’s common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU’s purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $2 million in 2019 (2018 - nil, 2017 - $1 million).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2019, the Corporation granted executive officers of the Corporation a total of 1.4 million stock options with a weighted average exercise price of $5.65 that vest after a three-year period and expire 7 years after issuance (2018 - 0.7 million stock options at $7.45; 2017 - 0.7 million stock options at $7.25). The expense recognized relating to these grants during 2019 was approximately $1 million (2018 - approximately $1 million, 2017 - approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2019, are outlined below:

	Options outstanding		
Range of exercise prices[1] *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 9.00	**3.3**	4.7	**6.34**
22.00 - 30.00	**0.5**	**0.1**	**23.44**
5.00 - 30.00	**3.8**	**4.2**	**8.41**

(1) Options currently exercisable as at Dec. 31, 2019.

30. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the US covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2019. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2019.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the US. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation posted a letter of credit in March 2019 for the amount of $83 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2018, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2019.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**1**	**10**
Administration expenses	**2**	**—**	**—**	**2**
Interest cost on defined benefit obligation	**19**	**3**	**1**	**23**
Interest on plan assets	**(12)**	**(1)**	**—**	**(13)**
Curtailment and amendment gain	**(3)**	**—**	**—**	**(3)**
Defined benefit expense	**13**	**4**	**2**	**19**
Defined contribution expense	**9**	**—**	**—**	**9**
Net expense	**22**	**4**	**2**	**28**

Year ended Dec. 31, 2018	Registered	Supplemental	Other	Total
Current service cost	9	2	1	12
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	18	3	1	22
Interest on plan assets	(13)	—	—	(13)
Defined benefit expense	15	5	2	22
Defined contribution expense	10	—	—	10
Net expense	25	5	2	32

Year ended Dec. 31, 2017	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	20	3	1	24
Interest on plan assets	(15)	—	—	(15)
Defined benefit expense	14	5	2	21
Defined contribution expense	11	—	—	11
Net expense	25	5	2	32

C. Status of Plans

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

As at Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**373**	**13**	**–**	**386**
Present value of defined benefit obligation	**(543)**	**(99)**	**(22)**	**(664)**
Funded status – plan deficit	**(170)**	**(86)**	**(22)**	**(278)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(3)**	**(5)**	**(2)**	**(10)**
Other long-term liabilities	**(167)**	**(81)**	**(20)**	**(268)**
Total amount recognized	**(170)**	**(86)**	**(22)**	**(278)**

As at Dec. 31, 2018	Registered	Supplemental	Other	Total
Fair value of plan assets	368	13	–	381
Present value of defined benefit obligation	(514)	(80)	(25)	(619)
Funded status – plan deficit	(146)	(67)	(25)	(238)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(5)	(5)	(1)	(11)
Other long-term liabilities	(141)	(62)	(24)	(227)
Total amount recognized	(146)	(67)	(25)	(238)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
As at Dec. 31, 2017	416	12	–	428
Interest on plan assets	13	–	–	13
Net return on plan assets	(25)	–	–	(25)
Contributions	5	6	1	12
Benefits paid	(42)	(5)	(1)	(48)
Administration expenses	(1)	–	–	(1)
Effect of translation on US plans	2	–	–	2
As at Dec. 31, 2018	368	13	–	381
Interest on plan assets	**12**	**1**	**–**	**13**
Net return on plan assets	**40**	**–**	**–**	**40**
Contributions	**6**	**4**	**1**	**11**
Benefits paid	**(50)**	**(5)**	**(1)**	**(56)**
Administration expenses	**(2)**	**–**	**–**	**(2)**
Effect of translation on US plans	**(1)**	**–**	**–**	**(1)**
As at Dec. 31, 2019	**373**	**13**	**–**	**386**

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

Year ended Dec. 31, 2019	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**66**	**—**	**66**
US	**—**	**28**	**—**	**28**
International	**—**	**102**	**—**	**102**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**40**	**—**	**40**
AA	**—**	**68**	**—**	**68**
A	**—**	**37**	**—**	**37**
BBB	**1**	**21**	**—**	**22**
Below BBB	**—**	**3**	**—**	**3**
Money market and cash and cash equivalents	**—**	**19**	**—**	**19**
Total	**1**	**384**	**1**	**386**

Year ended Dec. 31, 2018	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	65	—	65
US	—	26	—	26
International	—	101	—	101
Private	—	—	1	1
Bonds				
AAA	—	48	—	48
AA	—	64	—	64
A	—	39	—	39
BBB	1	21	—	22
Below BBB	—	3	—	3
Money market and cash and cash equivalents	(2)	14	—	12
Total	(1)	381	1	381

Plan assets do not include any common shares of the Corporation at Dec. 31, 2019, and Dec. 31, 2018. The Corporation charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2019 (2018 - $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2017	561	87	27	675
Current service cost	9	2	1	12
Interest cost	18	3	1	22
Benefits paid	(42)	(5)	(1)	(48)
Actuarial gain arising from demographic assumptions	—	—	—	—
Actuarial loss arising from financial assumptions	(35)	(7)	(2)	(44)
Actuarial gain (loss) arising from experience adjustments	—	—	(1)	(1)
Effect of translation on US plans	3	—	—	3
Present value of defined benefit obligation as at Dec. 31, 2018	514	80	25	619
Current service cost	**7**	**2**	**1**	**10**
Interest cost	**19**	**3**	**1**	**23**
Benefits paid	**(51)**	**(4)**	**(1)**	**(56)**
Curtailment	**(3)**	**—**	**—**	**(3)**
Actuarial loss arising from demographic assumptions	**—**	**—**	**(2)**	**(2)**
Actuarial (gain) loss arising from financial assumptions	**57**	**9**	**2**	**68**
Actuarial (gain) loss arising from experience adjustments	**2**	**9**	**(4)**	**7**
Effect of translation on US plans	**(2)**	**—**	**—**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2019	**543**	**99**	**22**	**664**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2019, is 15.6 years.

F. Contributions

The expected employer contributions for 2020 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**4**	**5**	**1**	**10**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2019			As at Dec. 31, 2018		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.0**	**3.0**	**3.0**	3.9	3.8	3.9
Rate of compensation increase	**2.8**	**3.0**	**—**	2.5	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**7.0**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.9**	**3.8**	**3.9**	3.3	3.3	3.4
Rate of compensation increase	**2.5**	**3.0**	**—**	2.6	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.4**	—	—	7.6
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health-care premium escalation	**—**	**—**	**—**	—	—	—

(1) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2030 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(3) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(4) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.

H. Sensitivity Analysis

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

	Canadian plans			**US plans**	
Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**84**	**15**	**2**	**3**	**1**
1% increase in the salary scale	**14**	**—**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**22**	**3**	**—**	**1**	**—**

31. Joint Arrangements

Joint arrangements at Dec. 31, 2019, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Heartland Generation Ltd., an affiliate of Energy Capital Partners
Pioneer Pipeline	Coal	50	Natural gas pipeline in Alberta operated by Tidewater
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

32. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2019	2018	2017
(Use) source:			
Accounts receivable	**261**	58	(228)
Prepaid expenses	**—**	19	(75)
Income taxes receivable	**(6)**	—	8
Inventory	**(13)**	(21)	(7)
Accounts payable, accrued liabilities and provisions	**(130)**	(97)	186
Income taxes payable	**9**	(3)	2
Change in non-cash operating working capital	**121**	(44)	(114)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2018	Net cash flows	New leases	Tax shield on tax equity financing	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2019
Long-term debt and lease obligations	3,267	**(70)**	**133**	**(35)**	**—**	**(42)**	**(41)**	**3,212**
Exchangeable securities	—	**350**	**—**	**—**	**—**	**—**	(24)	**326**
Dividends payable (common and preferred)	58	**(85)**	**—**	**—**	**64**	**—**	**—**	**37**
Total liabilities from financing activities	3,325	**195**	**133**	**(35)**	**64**	**(42)**	**(65)**	**3,575**

	Balance Dec. 31, 2017	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2018
Long-term debt and finance lease obligations	3,707	(540)	10	—	95	(5)	3,267
Dividends payable (common and preferred)	34	(86)	—	107	—	3	58
Total liabilities from financing activities	3,741	(626)	10	107	95	(2)	3,325

33. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2019	2018	Increase/ (decrease)
Long-term debt[1]	**3,212**	3,267	**(55)**
Exchangeable securities	**326**	—	**326**
Equity			
Common shares	**2,978**	3,059	**(81)**
Preferred shares	**942**	942	**—**
Contributed surplus	**42**	11	**31**
Deficit	**(1,455)**	(1,496)	**41**
Accumulated other comprehensive income	**454**	481	**(27)**
Non-controlling interests	**1,101**	1,137	**(36)**
Less: available cash and cash equivalents[2]	**(411)**	(89)	**(322)**
Less: principal portion of restricted cash on TransAlta OCP Bonds[3]	**(10)**	(27)	**17**
Less: fair value asset of hedging instruments on long-term debt[4]	**(7)**	(10)	**3**
Total capital	**7,172**	7,275	**(103)**

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

The Corporation's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain a strong financial position that enables the Corporation to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles. The Corporation has an investment-grade credit rating from DBRS (stable outlook). In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised their rating outlook to stable from positive. During 2019, Fitch Ratings downgraded the Corporation below investment grade to BB+ with a stable outlook; DBRS reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's downgraded the Corporation's Unsecured Debt rating and Issuer Rating to BB + with stable outlook. The Corporation remains focused on strengthening its financial position and cash flow coverage ratios. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing.

Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. These ratios are summarized in the table below:

As at Dec. 31	2019	2018	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.5**	4.8	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**19.0**	20.8	20 to 25
Adjusted net debt to adjusted comparable earnings before interest, taxes, depreciation and amortization (times)	**3.9**	3.6	3.0 to 3.5

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO less the termination payments for the Sundance B and C PPAs plus interest on debt, exchangeable securities and lease obligations (net of capitalized interest) divided by interest on debt, exchangeable securities and lease obligations (net of capitalized interest) plus 50 per cent of dividends paid on preferred shares. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less the termination payments for the Sundance B and C PPAs less 50 per cent of dividends paid on preferred shares divided by adjusted net debt (current and long-term debt plus exchangeable securities plus 50 per cent of outstanding preferred shares less available cash and cash equivalents less principal portion of TransAlta OCP restricted cash and including fair value assets of hedging instruments on debt). The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Adjusted Comparable Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is calculated as adjusted net debt divided by adjusted comparable EBITDA. Adjusted comparable EBITDA is calculated as earnings before interest, taxes, depreciation and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations as well as the termination payments for the Sundance B and C PPAs. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified ranges while the Corporation executes its coal-to-gas transition and growth strategy, but we remain focused on maintaining a strong balance sheet.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, Invest in PP&E and Make Acquisitions

For the years ended Dec. 31, 2019 and 2018, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	**2019**	2018	**Increase (decrease)**
Cash flow from operating activities	**849**	820	**29**
Change in non-cash working capital	**(121)**	44	**(165)**
Cash flow from operations before changes in working capital	**728**	864	**(136)**
Dividends paid on common shares	**(45)**	(46)	**1**
Dividends paid on preferred shares	**(40)**	(40)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(106)**	(165)	**59**
Property, plant and equipment expenditures	**(417)**	(277)	**(140)**
Inflow	**120**	336	**(216)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2019, $1.3 billion (2018 - $0.9 billion) of the Corporation's available credit facilities were not drawn.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

34. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2019, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables	Canada	60.4	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2019	2018	2017
Total compensation	**30**	17	24
Comprised of:			
Short-term employee benefits	**13**	11	14
Post-employment benefits	**2**	2	2
Termination benefits	**2**	—	—
Share-based payments	**13**	4	8

35. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas, transportation and other contracts	125	125	120	128	131	1,493	**2,122**
Transmission	9	5	4	3	—	—	**21**
Coal supply and mining agreements	147	16	16	16	8	14	**217**
Long-term service agreements	50	22	32	17	15	14	**150**
Operating leases	4	2	2	2	3	64	**77**
Growth	535	254	196	270	13	—	**1,268**
TransAlta Energy Transition Bill	6	6	6	6	—	—	**24**
Total	**876**	**430**	**376**	**442**	**170**	**1,585**	**3,879**

A. Natural Gas, Transportation and Other Contracts

Includes fixed price or volume natural gas purchase and transportation contracts. Other contracts relate to commitments for goods and services.

B. Transmission

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

C. Coal Supply and Mining Agreements

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

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

D. Long-Term Service Agreements

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

E. Operating Leases

Includes lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Prior to the adoption of IFRS 16 (refer to Note 3(A)(I) for further details), operating lease expenses were recognized as incurred in the statement of earnings. During the year ended Dec. 31, 2018, $8 million (2017 - $7 million) was recognized as an expense in respect of operating leases. Sublease payments received during 2019, 2018 and 2017 were less than $1 million. No contingent rental payments were made in respect of operating leases.

F. Growth

Commitments for growth relate to the following projects: coal-to-gas conversions and repowering Sudance Unit 5, Kaybob cogeneration, Windrise, Windcharger and Skookumchuck and any final costs associated with the Big Level and Antrim projects. Refer to Note 4 for further details on these projects.

G. TransAlta Energy Transition Bill Commitments

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement, we have committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required. As of Dec. 31, 2019, the Corporation has funded approximately US$37 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

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

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

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

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

IV. Keephills 1 Superheater
Keephills Unit 1 was taken offline from Mar. 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool is attempting to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. TransAlta denied the Balancing Pool had the right to do so. The Alberta Court of Queen's Bench confirmed that the Balancing Pool has a right under the PPA to commence an arbitration, independent of the PPA buyer. On Sept. 4, 2019, the Alberta Court of Appeal upheld the lower court's decision. TransAlta sought permission to appeal the Alberta's Court of Appeal's decision to the Supreme Court of Canada. The application was denied and the matter will now proceed to arbitration, with a hearing potentially sometime in 2020.

V. Sundance A Decommissioning
TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the mine. The Balancing Pool filed a statement of intent to participate as an intervener because it disagrees that, amongst other things, the mine decommissioning costs should be included. TransAlta anticipates it will receive payment from the Balancing Pool in 2020 for its decommissioning costs; however, the amount is uncertain.

VI. Hydro PPA Renewable Energy Credits
The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $27 million, earned by the Hydro plants under the *Carbon Competitiveness Incentive Regulation* in 2018 and 2019. Refer to Note 2(A) and 2(F)(IV) for the accounting policies on these credits. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. The Corporation anticipates this dispute will be resolved by the end of 2021.

VII. Direct Assigned Capital Deferral Account Application

AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 direct assigned capital deferral account for the Edmonton region 240 kV line upgrades project (the "Proceeding"). TransAlta is a secondary applicant in the Proceeding. Altalink and TransAlta seek to have their costs approved by the AUC as reasonable and prudent. The Enoch Cree Nation ("ECN") and the Consumers' Coalition of Alberta are registered participants in the Proceeding. Currently Altalink, ECN and TransAlta's interests are closely aligned. TransAlta believes it has a reasonable chance of having its costs (estimated at about $21 million) approved.

36. Segment Disclosures

A. Description of Reportable Segments

The Corporation has eight reportable segments as described in Note 1.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	816	571	209	160	312	156	129	(6)	2,347
Fuel, carbon compliance and purchased power	570	416	74	9	16	7	—	(6)	1,086
Gross margin	246	155	135	151	296	149	129	—	1,261
Operations, maintenance and administration	138	67	44	37	50	36	30	73	475
Depreciation and amortization	233	83	41	48	124	32	2	27	590
Asset impairment charge (reversal)	15	(10)	—	—	—	2	—	18	25
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	(88)	—	—	—	—	—	—	—	(88)
Taxes, other than income taxes	13	3	1	—	8	3	—	1	29
Termination of Sundance B and C PPAs	(56)	—	—	—	—	—	—	—	(56)
Net other operating expense (income)	(40)	—	(1)	—	(10)	—	—	2	(49)
Operating income (loss)	31	12	50	66	124	76	97	(121)	335
Finance lease income	—	—	6	—	—	—	—	—	6
Net interest expense									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	442	232	165	282	156	67	(7)	2,249
Fuel, carbon compliance and purchased power	666	314	96	8	17	6	—	(7)	1,100
Gross margin	246	128	136	157	265	150	67	—	1,149
Operations, maintenance and administration	171	61	48	37	50	38	24	86	515
Depreciation and amortization	241	74	43	49	110	30	2	25	574
Asset impairment charge	38	—	—	—	12	—	—	23	73
Taxes, other than income taxes	13	5	1	—	8	3	—	1	31
Termination of Sundance B and C PPAs (Note 9)	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(41)	—	—	—	(6)	—	—	—	(47)
Operating income (loss)	(19)	(12)	44	71	91	79	41	(135)	160
Finance lease income	—	—	8	—	—	—	—	—	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets									1
Earnings before income taxes									(96)

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	999	435	261	135	287	121	69	—	2,307
Fuel, carbon compliance and purchased power	585	293	101	14	17	6	—	—	1,016
Gross margin	414	142	160	121	270	115	69	—	1,291
Operations, maintenance and administration	192	51	50	31	48	37	24	84	517
Depreciation and amortization	317	73	38	37	111	31	2	26	635
Asset impairment reversals	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	13	4	1	—	8	3	—	1	30
Net other operating income	(40)	—	(9)	—	—	—	—	—	(49)
Operating income (loss)	(88)	14	80	53	103	44	43	(111)	138
Finance lease income	—	—	11	43	—	—	—	—	54
Net interest expense									(247)
Foreign exchange loss									(1)
Gain on sale of assets									2
Earnings before income taxes									(54)

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
PP&E	**2,540**	**352**	**392**	**489**	**1,947**	**469**	**1**	**17**	**6,207**
Right of use assets	**68**	**—**	**—**	**4**	**56**	**6**	**—**	**12**	**146**
Intangible assets	**41**	**6**	**2**	**37**	**173**	**5**	**9**	**45**	**318**
Goodwill	—	—	—	—	**176**	**258**	**30**	**—**	**464**

As at Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
PP&E	2,587	332	391	554	1,799	481	1	19	6,164
Intangible assets	81	7	4	41	173	4	11	52	373
Goodwill	—	—	—	—	175	259	30	—	464

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**114**	**8**	**36**	**6**	**229**	**23**	**—**	**1**	**417**
Intangible assets	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**12**	**14**

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	101	14	21	6	117	16	—	2	277
Intangible assets	3	—	—	—	—	—	—	17	20

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	116	35	31	114	20	16	—	6	338
Intangible assets	5	1	—	29	—	—	—	16	51

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

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

Year ended Dec. 31	**2019**	2018	2017
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**590**	574	635
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**119**	136	73
Depreciation and amortization on the Consolidated Statements of Cash Flows	**709**	710	708

C. Geographic Information

I. Revenues

Year ended Dec. 31	2019	2018	2017
Canada	**1,460**	1,573	1,663
US	**727**	511	509
Australia	**160**	165	135
Total revenue	**2,347**	2,249	2,307

II. Non-Current Assets

	Property, plant and equipment		Right of use assets		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Canada	**4,854**	4,953	**109**	—	**213**	273	**75**	101	**418**	417
US	**863**	657	**33**	—	**68**	59	**47**	50	**46**	47
Australia	**490**	554	**4**	—	**37**	41	**76**	83	**—**	—
Total	**6,207**	6,164	146	—	**318**	373	**198**	234	**464**	464

D. Significant Customer

During the year ended Dec. 31, 2019, sales to one customer represented 11 per cent of the Corporation's total revenue (2018 - one customer represented 19 per cent).

Exhibit 1

(Unaudited)

The information set out below is referred to as "unaudited" as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2019:

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

1.48 times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.