CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2013

Independent Auditor's Report

To the Share Owners of Canadian Utilities Limited

We have audited the accompanying consolidated financial statements of Canadian Utilities Limited, which comprise the consolidated balance sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for the years ended December 31, 2013 and December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited as at December 31, 2013, December 31, 2012 and January 1, 2012 and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 19, 2014

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CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Year Ended December 31 2013	2012
			(Note 5)
Revenues	7	**3,381**	3,039
Costs and expenses			
Salaries, wages and benefits		**(469)**	(455)
Energy transmission and transportation		**(139)**	(126)
Plant and equipment maintenance		**(244)**	(242)
Fuel costs		**(331)**	(268)
Purchased power		**(75)**	(67)
Materials and consumables		**(43)**	(38)
Depreciation, amortization and impairment	13	**(478)**	(412)
Franchise fees		**(186)**	(161)
Property and other taxes		**(89)**	(86)
Other	8	**(278)**	(234)
		(2,332)	(2,089)
		1,049	950
Earnings from investment in ATCO Structures & Logistics	15	**41**	32
Earnings from investment in joint ventures	16	**(24)**	2
Operating profit		**1,066**	984
Interest income		**9**	13
Interest expense	19	**(282)**	(269)
Net finance costs		**(273)**	(256)
Earnings before income taxes		**793**	728
Income taxes	9	**(187)**	(156)
Earnings for the year		**606**	572
Earnings attributable to:			
Equity owners of the Company		**587**	553
Equity preferred share owners of subsidiary company		**19**	19
		606	572
Earnings per Class A and Class B share	25	**$ 2.10**	$ 2.03
Diluted earnings per Class A and Class B share	25	**$ 2.09**	$ 2.02

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	2013	2012
			Year Ended December 31
			(Note 5)
Earnings for the year		**606**	572
Other comprehensive income (loss), net of income taxes:			
Items that will not be reclassified to earnings:			
Retirement benefits	10, 29	**223**	(149)
Share of other comprehensive income of ATCO Structures & Logistics	10, 15	**2**	(1)
Share of other comprehensive income of joint ventures	10, 16	**(2)**	-
		223	(150)
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges	10	**9**	(3)
Foreign currency translation adjustment	10	**(30)**	(2)
Share of other comprehensive income of ATCO Structures & Logistics	10, 15	**(3)**	(2)
Share of other comprehensive income of joint ventures	10, 16	**1**	2
		(23)	(5)
		200	(155)
Comprehensive income for the year		**806**	417
Comprehensive income attributable to:			
Equity owners of the Company		**787**	398
Equity preferred share owners of subsidiary company		**19**	19
		806	417

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET

(millions of Canadian Dollars)	Note	December 31 2013	December 31 2012	January 1 2012
			(Note 5)	*(Note 5)*
ASSETS				
Current assets				
Cash and cash equivalents		**498**	349	586
Accounts receivable		**477**	530	407
Finance lease receivables	11	**8**	7	6
Inventories	12	**90**	79	79
Prepaid expenses and other current assets		**32**	59	45
		1,105	1,024	1,123
Non-current assets				
Property, plant and equipment	13	**12,905**	11,153	9,363
Intangibles	14	**370**	329	291
Investment in ATCO Structures & Logistics	15	**190**	174	152
Investment in joint ventures	16	**98**	140	139
Finance lease receivables	11	**319**	340	346
Other assets		**64**	58	69
Total assets		**15,051**	13,218	11,483
LIABILITIES				
Current liabilities				
Bank indebtedness	17	**2**	-	-
Accounts payable and accrued liabilities		**777**	785	527
Asset retirement obligations and other provisions	18	**55**	43	43
Other current liabilities		**13**	15	36
Long-term debt	19	**138**	4	139
Non-recourse long-term debt	19	**39**	30	24
		1,024	877	769
Non-current liabilities				
Deferred income tax liabilities	9	**651**	464	427
Asset retirement obligations and other provisions	18	**137**	187	178
Retirement benefit obligations	29	**275**	583	388
Deferred revenues	20	**1,386**	1,170	1,024
Other liabilities	21	**70**	123	113
Long-term debt	19	**5,988**	5,284	4,213
Non-recourse long-term debt	19	**126**	156	185
Total liabilities		**9,657**	8,844	7,297
EQUITY				
Equity preferred shares	24	**1,115**	723	724
Equity preferred shares of subsidiary company	24	**343**	343	343
Class A and Class B share owners' equity				
Class A and Class B shares	25	**803**	667	621
Contributed surplus	28	**15**	15	1
Retained earnings		**3,157**	2,642	2,508
Accumulated other comprehensive income	10	**(39)**	(16)	(11)
		3,936	3,308	3,119
Total equity		**5,394**	4,374	4,186
Total liabilities and equity		**15,051**	13,218	11,483

See accompanying Notes to Consolidated Financial Statements.

[Original signed by N.C. Southern]
DIRECTOR

[Original signed by J.W Simpson]
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(millions of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares [1]	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
January 1, 2012	5	621	1,067	1	2,508	(11)	4,186
Earnings for the year		-	-	-	572	-	572
Shares issued, net of issue costs	24, 25	58	294	-	-	-	352
Shares redeemed	24	-	(295)	-	-	-	(295)
Dividends	26	-	-	-	(280)	-	(280)
Share-based compensation	28	(12)	-	14	(8)	-	(6)
Other comprehensive loss	10	-	-	-	-	(155)	(155)
Losses on retirement benefits transferred to retained earnings	10, 29	-	-	-	(150)	150	-
December 31, 2012	5	**667**	**1,066**	**15**	**2,642**	**(16)**	**4,374**
Earnings for the year		**-**	**-**	**-**	**606**	**-**	**606**
Shares issued, net of issue costs	24, 25	**134**	**392**	**-**	**-**	**-**	**526**
Dividends	26	**-**	**-**	**-**	**(314)**	**-**	**(314)**
Share-based compensation	28	**2**	**-**	**-**	**-**	**-**	**2**
Other comprehensive income	10	**-**	**-**	**-**	**-**	**200**	**200**
Gains on retirement benefits transferred to retained earnings	10, 29	**-**	**-**	**-**	**223**	**(223)**	**-**
December 31, 2013		**803**	**1,458**	**15**	**3,157**	**(39)**	**5,394**

(1) Includes equity preferred shares and equity preferred shares of subsidiary company.

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian Dollars)	Note	Year Ended December 31 2013	2012
			(Note 5)
Operating activities			
Earnings for the year		**606**	572
Adjustments for:			
Depreciation, amortization and impairment		**478**	412
Earnings from investment in ATCO Structures & Logistics		**(41)**	(32)
Dividends received from ATCO Structures & Logistics		**24**	7
Earnings from investment in joint ventures		**24**	(2)
Dividends and distributions received from joint ventures		**18**	3
Income taxes		**187**	156
Unearned availability incentives		**(22)**	10
Contributions by customers for extensions to plant		**266**	184
Amortization of customer contributions		**(50)**	(43)
Net finance costs		**273**	256
Income taxes paid		**(75)**	(90)
Other		**(1)**	16
		1,687	1,449
Changes in non-cash working capital	30	**114**	(97)
Cash flow from operations		**1,801**	1,352
Investing activities			
Additions to property, plant and equipment		**(2,245)**	(2,149)
Proceeds on disposal of property, plant and equipment		**2**	7
Additions to intangibles		**(88)**	(73)
Changes in non-cash working capital	30	**(79)**	231
Other		**(8)**	(8)
		(2,418)	(1,992)
Financing activities			
Issue of long-term debt		**1,326**	1,311
Repayment of long-term debt		**(417)**	(364)
Repayment of non-recourse long-term debt		**(30)**	(24)
Issue of equity preferred shares		**400**	300
Redemption of equity preferred shares		**-**	(300)
Issue of Class A shares		**3**	2
Dividends paid on equity preferred shares		**(45)**	(35)
Dividends paid on equity preferred shares of subsidiary company		**(19)**	(19)
Dividends paid to Class A and Class B share owners		**(116)**	(168)
Interest paid		**(312)**	(286)
Other		**(20)**	(14)
		770	403
Foreign currency translation		**(6)**	-
Cash position (1)			
Increase (decrease)		**147**	(237)
Beginning of year		**349**	586
End of year		**496**	349

(1) Cash position consists of cash and cash equivalents less current bank indebtedness and includes $46 million (2012 - $24 million) which is not available for general use by the Company.

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013

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

1. CORPORATE INFORMATION

Alberta-based Canadian Utilities Limited is engaged in utilities (pipelines, natural gas and electricity transmission and distribution), energy (power generation, natural gas gathering, processing, storage and liquids extraction) and technologies (business systems solutions). Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 700, 909 – 11th Avenue SW, Calgary, Alberta, T2R 1N6 and its registered office is 20th Floor, 10035 – 105 Street, Edmonton, Alberta T5J 2V6. The Company is principally controlled by ATCO Ltd. and its controlling share owner, R.D. Southern.

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of its investments in joint operations and its equity accounted investments in ATCO Structures & Logistics and joint ventures (the Company).

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The accompanying consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

The Board of Directors (Board) authorized the issue of the consolidated financial statements on February 19, 2014.

BASIS OF MEASUREMENT

The consolidated financial statements have been prepared on a historic cost basis, except for derivative financial instruments, defined benefit pension and other employee retirement benefit liabilities and cash-settled share-based compensation liabilities.

Certain comparative figures have been reclassified to conform to the current presentation.

USE OF ESTIMATES AND JUDGMENT

Management makes judgments, estimates and assumptions that affect the application of policies and reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities. Such estimates mainly relate to unsettled transactions and events at the date of the consolidated financial statements. Facts and circumstances may change and actual results could differ from those estimates. Management uses judgment and currently available information to make these estimates and these estimates are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods. Note 4 outlines the significant judgments and estimates made by the Company.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CHANGE IN ACCOUNTING POLICIES

Joint arrangements

The Company adopted IFRS 11 *Joint Arrangements* effective January 1, 2013. Together with IFRS 11, the Company also adopted IFRS 10 *Consolidated Financial Statements*, IFRS 12 *Disclosure of Interests in Other Entities*, and consequential amendments to IAS 28 *Investments in Associates and Joint Ventures* and IAS 27 *Separate Financial Statements*. A joint arrangement is an arrangement in which two or more parties have joint control. Under IFRS 11, the Company classifies its interests in joint arrangements as either joint operations or joint ventures depending on the Company's rights to the assets and obligations for the liabilities of the arrangements. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances.

Joint operations continue to be proportionately consolidated by including the Company's share of assets, liabilities, revenues, expenses and other comprehensive income in the respective consolidated accounts.

Joint ventures, which previously were proportionately consolidated, now apply the equity method of accounting. Under the equity method, the Company's share of individual assets and liabilities are replaced with a net investment in joint ventures amount in the consolidated balance sheet and individual revenues and expenses are replaced with an earnings from investment in joint ventures amount in the consolidated statement of earnings. This change in accounting policy had no impact on the Company's net assets, earnings or earnings per share.

The Company applied the new policy retrospectively according to the transitional provisions of IFRS 11. The Company recognized the deemed cost of its investments in joint ventures at January 1, 2012, as the net of the carrying amounts of the assets and liabilities previously proportionately consolidated by the Company.

The effects of the change on the consolidated financial statements are summarized in Note 5.

Consolidation

IFRS 10 replaces the previous guidance on control and consolidation. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure or rights to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. As a result of the adoption of IFRS 10 effective January 1, 2013, and according to the transitional provisions of IFRS 10, the Company re-assessed its control conclusions and determined that there were no changes in the consolidation status of any of its subsidiaries.

Disclosure

IFRS 12 sets out the annual disclosure requirements for the Company's interests in subsidiaries, joint arrangements and associates. The adoption of IFRS 12 effective January 1, 2013, resulted in additional disclosures in the Company's consolidated financial statements for the year ended December 31, 2013.

IFRS 7 *Financial Instruments: Disclosures* has been amended to require annual disclosure of information on rights to offset financial instruments and related arrangements. The Company adopted this amendment effective January 1, 2013. The amendments to IFRS 7 resulted in additional disclosures in the Company's consolidated financial statements for the year ended December 31, 2013. The new disclosures provide information that is useful in evaluating the effect of netting arrangements on the Company's financial position. The new disclosures are required for all recognized financial instruments that are offset according to IAS 32 *Financial Instruments: Presentation*. They also apply to recognized financial instruments that are subject to an enforceable master netting arrangement, irrespective of whether the financial instruments are offset according to IAS 32.

Fair value measurement

The Company adopted IFRS 13 *Fair Value Measurement* effective January 1, 2013. The standard improves consistency and reduces complexity by providing a precise definition of fair value. It also provides a single source of fair value measurement and disclosure requirements for use across IFRS. The requirements do not extend the use of fair value accounting but provide guidance on how it should be applied where its use is already required or permitted by other IFRS standards. Adopting this standard did not have significant impact on the Company's financial statements.

Impairment of assets

IAS 36 *Impairment of Assets* was amended to remove the unintended consequences of IFRS 13 on the disclosures required under IAS 36. These unintended consequences would have required the disclosure of the recoverable amount of a cash-generating unit (CGU) containing goodwill and indefinite-lived intangible assets, regardless of whether an impairment had been recognized or reversed as well as other fair value information. In addition, where an impairment loss has been recognized or reversed, these amendments require disclosure of the recoverable amounts for the assets or CGUs and expanded disclosures for recoverable amounts based on fair value less costs of disposal. These amendments are effective retrospectively for annual periods beginning on or after January 1, 2014 with earlier application permitted, provided IFRS 13 is also applied. While not required to adopt these amendments until 2014, the Company adopted them retrospectively effective January 1, 2013.

Retirement benefits

IAS 19 *Employee Benefits* was amended to change the recognition and measurement of defined benefit pension expense and termination benefits and increase disclosures. The Company adopted IAS 19 effective January 1, 2013. The Company applied the amended policy to retirement benefits on and after January 1, 2012, according to transition provisions of IAS 19. The Company was not required to adjust the carrying amount of assets or liabilities for changes in employee benefit costs that were included in the carrying amount before the date of initial application.

Under IAS 19, the cost of retirement benefits for defined benefit plans includes net interest expense. This expense is calculated by applying the discount rate to the net defined benefit asset or liability at the beginning of the annual period. It also takes into account any changes in the net defined benefit asset or liability during the period as a result of contributions and benefit payments. Previously, the interest expense on plan obligations and the expected return on plan assets were calculated separately. The expected return on assets was generally higher than the liability discount rate because it included an equity and management premium. Consequently, this change in the calculation will result in higher pension expense. There is no change in the discount rate, which reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Vested and unvested prior service costs will now be recognized immediately in earnings in the period of a plan amendment. Previously, the unvested portion of the prior service costs was amortized on a straight line basis over the period until the benefits were vested. Asset management costs are now netted against the return on plan assets, which is recognized in other comprehensive income. Previously, asset management costs were charged to earnings during the period in which they were incurred.

Retirement benefit costs for defined benefit plans were previously included in salaries, wages and benefits. With this change, service cost will continue to be recognized as an expense in salaries, wages and benefits, but net interest expense will be recognized in interest expense.

The effects of this change in accounting policy on the Company's consolidated statements of earnings, comprehensive income and cash flows are summarized in Note 5.

There were no changes to the employee or employer funding contributions relating to the Company's defined benefit plans as a result of the adoption of IAS 19.

Presentation of items in other comprehensive income

IAS 1 *Presentation of Financial Statements* was amended to group items in other comprehensive income into items that could be reclassified to earnings at a future point in time and items that will never be reclassified to earnings. Items which could be reclassified to earnings include cash flow hedges and exchange differences on translation of foreign operations. Items that will never be reclassified to earnings are actuarial gains and losses on retirement benefits. The Company adopted the amendment effective January 1, 2013. The amendment only affected presentation and had no impact on the Company's financial position or results of operations.

CONSOLIDATION

Subsidiaries are consolidated from the date on which control is obtained until the date that such control ceases. Control exists where the Company possesses power over the investee, has exposure or rights to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns.

Principal operating subsidiaries and significant investments in associates are listed below. Subsidiaries are wholly owned, unless otherwise indicated.

Principal Operating Subsidiaries	Principal Activity
CU Inc.	Holding company
ATCO Electric	Electricity transmission and distribution
ATCO Gas	Natural gas distribution
ATCO Pipelines	Natural gas transmission
ATCO Australia	Holding company
ATCO Gas Australia	Natural gas distribution
ATCO Power Australia	Power generation
ATCO I-Tek Australia	Information systems and technologies
ATCO Power	Power generation
ATCO Energy Solutions	Natural gas gathering, processing, storage and liquids extraction
ATCO I-Tek	Information systems and technologies
ATCO Structures & Logistics (1)	Manufacturing, logistics and noise abatement

(1) *The Company has an ownership interest of 24.5% and ATCO Ltd., the Company's parent, has an ownership interest of 75.5%. The Company accounts for its investment in ATCO Structures & Logistics under the equity method.*

All intragroup balances and transactions have been eliminated on consolidation. The financial statements of the principal operating subsidiaries are prepared for the same reporting period and apply accounting policies consistent with the Company.

JOINT ARRANGEMENTS

The Company classifies its interests in joint arrangements as either joint operations or joint ventures depending on the Company's rights to the assets and obligations for the liabilities of the arrangements. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances.

Joint operations are proportionately consolidated by including the Company's share of assets, liabilities, revenues, expenses and other comprehensive income in the respective consolidated accounts.

Joint ventures are accounted for under the equity method of accounting. Under this method, the Company's interests in joint ventures are initially recognized at cost and are adjusted thereafter to recognize the Company's share of post-acquisition profits or losses, movements in other comprehensive income and dividends or distributions received.

When the Company's share of losses in a joint venture equals or exceeds its interests in the joint venture, the Company does not recognize further losses, unless it has incurred obligations or made payments on behalf of the joint venture. The Company's interest in the joint venture includes any long-term interests that, in substance, form part of the Company's net investment in the joint venture.

The Company determines at each reporting date whether there is any objective evidence that its interests in joint ventures are impaired. An impairment is recognized in earnings when the carrying value of the Company's interest in each individual joint venture exceeds its recoverable amount. The recoverable amount is the higher of fair value less costs of disposal and its value in use. Any impairment loss recognized forms part of the carrying amount of the investment. Any reversal of that impairment loss is recognized to the extent that the recoverable amount of the investment subsequently increases.

Unrealized gains on transactions between the Company and its joint ventures are eliminated to the extent of the Company's interest in the joint ventures. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of the joint ventures have been changed where necessary to ensure consistency with the policies adopted by the Company.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition-related costs are expensed in the period incurred.

RATE REGULATION

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, and the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc.; ATCO Gas Australia is a wholly owned subsidiary of Canadian Utilities Limited. Collectively, these entities are referred to in these consolidated financial statements as the utilities.

Nature and economic effects of rate regulation in Canada

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated by the AUC. Yukon Electrical is regulated by the Yukon Utilities Board, and Northland Utilities (Yellowknife) and Northland Utilities (NWT) are regulated by the Northwest Territories Public Utilities Board. The regulators administer acts and regulations covering such matters as rates, financing, and service area.

Effective January 1, 2013, ATCO Gas and the distribution operations of ATCO Electric moved to a form of rate regulation called Performance Based Regulation (PBR). Like the previous cost of service regulatory model, PBR should continue to allow distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. The current PBR period applies for a period of five years from 2013 to 2017. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five-year period. Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow companies to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control that are material, should not significantly influence the I Factor, are prudently incurred, are recurring, and could vary greatly from year to year (Y Factor), or are unforeseen, and not likely to recur (Z Factor)

PBR does not apply to the transmission operations of ATCO Electric and ATCO Pipelines. These operations continue to be subject to a cost of service regulatory mechanism under which the regulators establish the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service; and (ii) to provide a fair and reasonable return on utility investment, or rate base. Since actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for the transmission operations of ATCO Electric and ATCO Pipelines is the aggregate of the regulator approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. These operations earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The regulator approves rates of return for the debt and preferred share components of rate base based on the historical and forecast weighted average cost of debt and preferred shares. The regulator also establishes the capital structure.

The transmission operations of ATCO Electric and ATCO Pipelines seek approval for their revenue requirement either by submitting general rate applications to the regulator or negotiating settlement with interested parties. In the latter case, the regulator monitors the negotiated settlement process and any agreement is subject to the regulator's approval. The regulator may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

The Battle River and Sheerness generating plants were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated Power Purchase Arrangements (PPAs) that were approved by the AUC. The PPAs are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

For PPAs expiring prior to 2019, ATCO Power has one year after the expiry of a PPA to determine whether to decommission the generating plant to fully recover decommissioning costs or to continue to operate the plant and be responsible for any incremental decommissioning costs above what has already been collected from the PPA purchaser. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner.

Nature and economic effects of rate regulation in Australia

ATCO Gas Australia is regulated mainly by the Economic Regulation Authority (ERA) of Western Australia. Rates are generally set for a five year Access Arrangement (or General Rate Application). However, the current period, which began on January 1, 2010, and ends on June 30, 2014, is only four and a half years because the year end for rate making purposes was switched from December 31 to June 30. ATCO Gas Australia is subject to a cost of service regulatory mechanism under which the ERA establishes the revenues for each year of the Access Arrangement to recover (i) a return on projected rate base, including income taxes; (ii) depreciation on the projected rate base; and (iii) projected operating costs.

Under the current Access Arrangement, ATCO Gas Australia is using the real method to determine revenue requirement and customer rates. Under this method, the impact of inflation is added to the rate base annually. The inflation impact is reflected in customer rates in future periods through the recovery of depreciation. Customer rates are adjusted annually through a mechanism which adjusts the approved rates in real dollars for actual inflation.

The real return is based on a deemed capital structure of 60% debt and 40% equity. This return was calculated using a cost of debt based on market rates for a benchmark sample of companies in Australia within the BBB credit band and a cost of equity, based on a capital asset pricing model. Income taxes are included in the return component of the revenue requirement.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities record revenues in earnings when amounts are billed to customers through customer rates consistent with the rate design approved by the regulator (see revenue recognition accounting policy below). Operating costs and expenses are recorded when incurred. When the costs are incurred in the construction of an asset and the benefits received meet the recognition criteria of an asset, the costs are included as part of the related property, plant and equipment or intangible asset.

SEGMENTED INFORMATION

Financial information that adjusts IFRS results to show the effect of rate regulation is used by the Company's Board and Office of the Chair to evaluate the performance of operating segments and determine resource allocation between operating segments. The Office of the Chair, comprised of the Chair, President and Chief Executive Officer and four other senior executives, is determined to be the Chief Operating Decision Maker (CODM). The CODM assesses performance of operations principally on the basis of earnings adjusted for regulatory items as shown in the segmented information disclosed in Note 6.

REVENUE RECOGNITION

Revenues from the regulated distribution of natural gas in Canada and Australia and the regulated distribution of electricity in Canada include variable charges and fixed charges. Variable charges are recognized using meter readings upon delivery of the commodity to customers and include an estimate of usage not yet billed; fixed charges are based on the provision of the distribution service during the period.

Revenues for the use of regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from the regulated transmission of natural gas are recognized based on AUC approved revenue requirement (cost of service).

Certain additions to property, plant and equipment, primarily in the utilities, are made with the assistance of non-refundable cash contributions from customers. These contributions are required when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific needs. Contributions will provide customers with ongoing access to the supply of natural gas or electricity. Therefore, these contributions are classified as deferred revenue and are recognized as revenue over the life of the related asset.

Revenues from power generating plants are recognized on delivery of output or on availability of delivery as prescribed by contractual arrangements. In addition, incentives and penalties associated with the Battle River and Sheerness PPAs are recognized in earnings on a straight-line basis as lease income. Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess is amortized to revenues on a straight-line basis over the remaining term of the PPA. Conversely, any shortfall will be expensed in the year the shortfall occurs.

Revenues from natural gas storage and processing capacity are recognized according to contractual arrangements. Revenues from the sale of natural gas liquids are recognized on delivery.

Revenues from the supply of contracted products and services are recorded using the percentage of completion method. The percentage of completion is based on either actual labor hours incurred as a proportion of the total labor estimated hours for the contract or contract costs incurred to date as a proportion of the total contract costs. Full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided. Billings in excess of earned revenue are classified as deferred revenues on the consolidated balance sheet.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. When the services of employees are used in the construction of an asset and the benefits received meet the recognition criteria of an asset, short-term employee benefits are included in the related property, plant and equipment or intangible asset.

FRANCHISE FEES

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fee revenues and expenses are, therefore, recognized separately and are not recorded on a net basis.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income taxes are recognized in earnings or in equity to the extent that equity items are affected. Income taxes related to items recognized in other comprehensive income are recognized in other comprehensive income.

Current taxes are calculated on taxable earnings using rates that have been enacted or substantively enacted as of the balance sheet date. Taxable earnings differ from earnings reported in the consolidated statement of earnings because they exclude items that are taxable or deductible in other years and items that are neither taxable nor deductible.

The Company includes penalties related to income taxes in income tax expense and interest on unpaid tax in interest expense.

Current tax assets and liabilities are offset to the extent the Company has the legal right to settle on a net basis and the Company intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Deferred income taxes are provided, using the liability method, on differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for accounting purposes (temporary differences).

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred income tax assets are recognized on deductible temporary differences and carry forward balances of unused tax losses or credits only to the extent that it is probable that taxable earnings will be available against which these items can be applied. Deferred income tax assets and liabilities are not recognized if the temporary difference arises from the initial recognition of goodwill or from the initial recognition of other assets and liabilities in a transaction (other than a business combination) that, at the time of the transaction, affects neither accounting earnings nor taxable earnings.

Deferred income tax assets and liabilities are recognized on temporary differences arising on investments in subsidiaries and joint arrangements, except where the Company 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.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, using tax rates that have been enacted or substantively enacted by the balance sheet date. If the expected tax rates change, deferred income taxes are adjusted to the new rates and the adjustment is booked to either earnings or equity, depending on the underlying temporary difference.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date. The carrying amount is reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the deferred income tax asset to be realized. Unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become probable that future taxable earnings will allow the deferred income tax assets to be realized.

Deferred income tax assets and liabilities are offset when there is a legally enforceable right to set off tax assets against tax liabilities, and when they relate to income taxes levied by the same taxation authority.

CASH AND CASH EQUIVALENTS

Cash equivalents consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short-term investments with maturities generally of 90 days or less at purchase.

Cash and cash equivalents which are restricted under the terms of project financing agreements or are only available for use within the joint arrangements, unless partner approval has been obtained, are considered not available for general use within the Company.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties, and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and accumulated impairment losses and include capitalized interest incurred during construction. Cost includes expenditures that are directly attributable to the acquisition or construction of the asset, such as materials, labour, borrowing costs, contracted services and asset retirement costs. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits associated with the item will flow to the Company and the cost can be measured reliably. The carrying amount of a replaced asset is derecognized when replaced. A gain or loss arising from the derecognition of an asset is recorded in earnings when the asset is derecognized.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period to the next major overhaul, which varies from three to eight years. The cost of repairs and maintenance activities which are performed every two years or less and do not extend or enhance the life of the asset are charged to earnings during the period in which they are incurred.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Residual values, method of depreciation and useful lives of the assets are reviewed annually and adjusted where necessary.

Interest on the funding attributable to qualifying assets is capitalized during construction and is depreciated as part of the total cost over the useful life of the asset. Capitalized interest is calculated using the effective interest rate method based on specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization commences when borrowing costs and expenditures are incurred at the onset of construction on assets of substantial duration. Interest capitalization ceases when construction of the asset is substantially complete.

Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress. Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Depreciation Rate
Utility transmission and distribution:		
Electricity transmission equipment	40 to 75 years	2.0 %
Electricity distribution equipment	15 to 75 years	2.4 %
Gas transmission equipment	3 to 81 years	2.4 %
Gas distribution plant and equipment	3 to 120 years	2.6 %
Power generation plant and equipment:		
Gas-fired	3 to 40 years	3.8 %
Coal-fired	5 to 47 years	3.0 %
Hydroelectric	50 years	2.1 %
Buildings	5 to 60 years	2.9 %
Other:		
Other plant, equipment and machinery	2 to 66 years	8.9 %

INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. These assets are recorded at cost less accumulated amortization and are amortized on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and between 75 and 100 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

The method of amortization and useful lives of the assets are reviewed annually and adjusted where necessary.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. Impairment is assessed and tested at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds its recoverable amount. The recoverable amount is the higher of the asset's fair value less costs of disposal and its value in use. Where fair value less costs of disposal is not reliably available, value in use is used as the recoverable amount.

An impairment charge may be reversed only if there is objective evidence that a change in the estimate used to determine the asset's recoverable amount since the last impairment was recognized is warranted. Where an impairment charge is subsequently reversed, the carrying amount of the asset (or CGU) is increased to the revised recoverable amount to the extent that it does not exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods. A reversal of an impairment charge is recognized immediately in earnings. After such a reversal, the depreciation or amortization charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

LEASES

The Company is party to certain arrangements that convey the right to use power generation and non-regulated electricity transmission assets. These arrangements are classified as leases, with the Company as the lessor. A lease is a finance lease when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments considered to be part of the leasing arrangement are apportioned between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized in a manner that produces a constant rate of return on the Company's investment in the lease and is included in revenue.

Certain assets under PPAs are classified as operating leases as the Company (as lessor) still retains substantially all the risks and rewards of ownership. Assets subject to operating leases are included in property, plant and equipment and are depreciated in a manner consistent with the Company's depreciation policy (see property, plant and equipment accounting policy above). Income from operating leases is recognized in earnings on a straight-line basis over the lease term.

Where the Company has purchased goods or services as a lessee, and the lease is an operating lease, rental payments are expensed on a straight-line basis over the life of the lease.

For both finance and operating leases, contingent rents are recognized in the consolidated statement of earnings in the period in which they are incurred. Contingent rent is that portion of lease payments that is not fixed in amount but varies based on a future factor, such as the amount of use or production.

PROVISIONS AND CONTINGENCIES

The Company recognizes provisions when there is a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be made. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

Management evaluates the likelihood of the contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

A contingent asset is not recognized in the consolidated financial statements. However, a contingent asset is disclosed where an inflow of economic benefits is probable.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) are legal and constructive obligations connected with the retirement of tangible long lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until settlement of the obligation, with the accretion expense recognized as interest expense. The asset is depreciated over its estimated useful life. The carrying value is evaluated annually, or more frequently if events or circumstances dictate, taking into account changes in the estimate of future cash flows and a discount rate that reflects the current market assessment of the time value of money.

FINANCIAL INSTRUMENTS

The Company classifies financial instruments at their initial recognition. Financial assets are classified as fair value through profit or loss, available for sale, held to maturity investments or loans and receivables. Financial liabilities are classified as fair value through profit or loss or amortized cost.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss, other than derivative instruments that are effective hedging instruments, are measured at fair value. Changes in fair value are recognized in earnings.

Available for sale

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Held to maturity

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition. Thereafter, they are measured at their amortized cost using the effective interest method. Investments in equity instruments that do not have an actively quoted price and whose fair value cannot be reliably measured are measured at cost.

Transaction costs

Transaction costs directly attributable to the acquisition or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt and preferred shares, classified as liabilities, are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt, non-recourse long-term debt and preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

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

Derecognition of financial instruments

Financial assets are derecognized when the right to receive cash flows from the financial assets has expired or been transferred and the Company has transferred substantially all the risks and rewards of ownership. Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

In estimating fair value, the Company utilizes quoted market prices when available. Models incorporating observable market data along with transaction specific factors are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input to the fair value measurement may affect placement within the fair value hierarchy levels. The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

An impairment of loans and receivables or held to maturity investments carried at amortized cost is recognized in earnings when the asset's carrying amount exceeds the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. A reduction in an impairment charge may be recognized if the decrease is related objectively to an event occurring after the impairment was recognized.

When an available for sale financial asset is impaired, the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. An impairment charge for an investment in an equity instrument classified as available for sale is not reversed. A reduction in an impairment charge for a debt instrument classified as available for sale may be recognized if the decrease is related objectively to an event occurring after the impairment was recognized.

Where an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the revised recoverable amount which does not exceed the carrying amount had no impairment charge been recognized in previous periods. A reversal of an impairment charge is recognized immediately in earnings.

DERIVATIVE FINANCIAL INSTRUMENTS

The Company uses various instruments, including forward contracts, swaps and options, to manage the risks from fluctuating exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for speculative purposes.

Contracts settled net in cash or in another financial asset, other than certain non-financial derivative contracts that meet the Company's own use requirements, are classified as derivatives and are recognized and measured as described in this policy. For own use contracts, an asset or liability is not recorded until the non-financial asset has been delivered.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative and the combined instrument is not measured at fair value through profit or loss. Embedded derivatives are measured at fair value at each balance sheet date and changes in the fair value are recognized in earnings.

The Company designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

a) A hedging instrument is designated as either:

i) A fair value hedge of a recognized asset or liability, or

ii) A cash flow hedge of either:

- A firm commitment in the case of a foreign currency transaction or a highly probable forecast transaction, or
- The variable future cash flows arising from a recognized asset or liability.

At inception of a hedge, the Company documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Company assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Company also assesses whether the hedging instrument is expected to be highly effective in the future.

A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized at the same time, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings at the same time as the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income (loss) and is subsequently transferred to earnings at the same time as the hedged item. The portion of the changes in fair value that are not effective at offsetting the hedged exposure is recognized in earnings.

If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Company ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings at the same time as the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

i) An anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied, or

ii) A cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

b) A non-hedge accounted derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

Non-performance risk, including the Company's own credit risk, is considered when determining the fair value of derivative financial instruments.

RETIREMENT BENEFITS

The Company accrues for its obligations under defined benefit pension and other post-employment benefit (OPEB) plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Pension plan assets at the balance sheet date are reported at market value. Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

The cost for defined benefit plans includes net interest expense. This expense is calculated by applying the discount rate to the net defined benefit asset or liability at the beginning of the annual period and takes into account projected contributions and benefit payments during the period.

For all plans, gains and losses resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligations are recognized in other comprehensive income in the period in which they occur. Immediately thereafter, those gains and losses are transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits and net interest expense is recognized in interest expense. The cost of defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment. When the services of employees are used in the construction of an asset and the benefits received meet the recognition criteria of an asset, the cost of retirement benefits is included as part of the related property, plant and equipment or intangible asset.

SHARE-BASED COMPENSATION PLANS

The Company expenses stock options. The Company determines the fair value of the options on the date of grant using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the options granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of the options is recorded in salaries, wages and benefits expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

Share appreciation rights are cash-settled and are measured at fair value using the Black-Scholes option pricing model by applying graded vesting, adjusted for estimated forfeitures. Share appreciation rights are recognized in salaries, wages and benefits expense over the vesting period, with corresponding liabilities recognized in accounts payable and accrued liabilities and other liabilities on the consolidated balance sheet. The liability is re-measured at each reporting period.

The mid-term incentive plan (MTIP) awards are equity settled with shares purchased on the secondary market. They are measured at fair value based on the purchase price of the Company's Class A non-voting shares at the date of grant. The awards are held by a trust until the shares are vested, at which time they are transferred to the employee. The fair value of the MTIP awards is recognized in salaries, wages and benefits expense over the vesting period, with a corresponding charge to contributed surplus. The trust is considered to be a special purpose entity and is consolidated in the Company's financial statements. The Class A non-voting shares, while held in trust, are accounted for as a reduction of share capital.

RELATED PARTY TRANSACTIONS

Transactions with related parties that are in the normal course of business are measured at the exchange amount. Transfers or business combinations between entities under common control are measured at the carrying amount.

FOREIGN CURRENCY TRANSLATION

The consolidated financial statements are presented in Canadian dollars. Each entity within the Company determines its own functional currency based on the primary economic environment in which it operates. On consolidation, assets and liabilities of foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the period. Gains or losses on translation are included in accumulated other comprehensive income in share owners' equity.

Transactions denominated in foreign currencies are translated at the rate of exchange in effect at the transaction date. Monetary items arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings. Non-monetary items, other than those measured at fair value, are not retranslated subsequent to initial recognition.

If the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in earnings.

ACCOUNTING CHANGES NOT YET ADOPTED

Certain new or amended standards or interpretations issued by the IASB or IFRIC do not have to be adopted in the current period. The Company has not early adopted these standards or interpretations, except for IAS 36 described earlier under impairment of assets. The standards which the Company anticipates will have a material effect on the consolidated financial statements or note disclosures are described below.

IFRS 9 *Financial Instruments* addresses, in its two finalized phases, the classification and measurement of financial assets and financial liabilities and hedge accounting, replacing the parts currently found in IAS 39 *Financial Instruments: Recognition and Measurement*. In the third and final outstanding phase of this standard, the IASB will address impairment of financial assets. The Company will quantify the effect when the final standard, including all phases, is issued.

There are no other standards or interpretations issued, but not yet effective, that the Company anticipates will have a material effect on the consolidated financial statements once adopted.

4. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The application of several accounting policies described above requires management judgments that could significantly affect the amounts recognized in the consolidated financial statements. The timely preparation of the consolidated financial statements also requires that management make a number of estimates and assumptions regarding matters that are uncertain at the date of estimate. Estimates of key variables used in the calculations, or changes to estimates, could have a material impact on the Company's financial position or performance. Material judgments and sources of estimation uncertainty are described below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Joint Arrangements

The adoption of IFRS 11 required judgments concerning the existence of joint control and the classification of the joint arrangement. The Company has joint control over its joint arrangements when unanimous consent is required from all parties to the contractual agreements for all relevant activities.

Joint arrangements that are structured as separate vehicles and that provide all parties with rights to the net assets of the entities under the arrangements are classified as joint ventures and are equity accounted.

Joint arrangements that are not structured as separate vehicles and that give all parties direct rights to the assets and obligations for the liabilities under the arrangements are classified as joint operations and are proportionately consolidated.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. Measurement uncertainty is increased where the Company is not the operator of a facility. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Leases

In determining whether the Company's power generation, non-regulated electricity transmission, and other contractual arrangements contain, or are, leases, the Company uses judgment to evaluate the terms and conditions of these agreements. For those agreements considered to contain or to be leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Company. This determination will result in the agreement being accounted for as either a finance or operating lease.

Income taxes

Accounting for income taxes requires the Company to make judgments with respect to changing tax legislation, regulations and interpretations thereof in the various jurisdictions in which the Company operates. Judgment is also applied in estimating probable outcomes, when temporary differences will reverse and whether tax assets are realizable.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

The estimate of usage not yet billed, which is included in revenues from the regulated distribution of natural gas and electricity, is based on an assessment of unbilled gas and electricity distribution services supplied to customers. This estimate is from the date of the last meter reading using historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Useful lives of property, plant and equipment and intangibles

Significant components of property, plant and equipment and intangible assets are depreciated and amortized over their estimated useful lives. Useful lives are determined on current facts and past experience, and consider the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. Useful life estimates are reviewed on a regular basis; however, actual lives may differ from the estimates.

Impairment of long-lived assets

If indicators of impairment exist for a CGU to which an asset belongs, an estimate of the recoverable amount is made to determine whether an impairment loss is to be recognized. The calculations used to determine the recoverable amounts include assumptions, such as the price for which the asset could be obtained or the future cash flows that will be produced by the asset or group of assets, discounted using an appropriate rate. Subsequent changes to these estimates or assumptions may significantly impact the carrying value of the assets within the respective CGU.

Retirement benefits

The Company accrues for its obligations under defined benefit pension and OPEB plans. It uses actuarial and other assumptions to estimate the projected benefit obligations and the associated expense related to the current period. Key assumptions include the long-term inflation rate, rates of future compensation and health-care cost increases and liability discount rates. Changes in these assumptions give rise to gains and losses which are recognized in other comprehensive income as incurred. The obligations are measured by discounting the Company's share of future payments under these plans. Actual payments may vary from the estimates used to project the obligations and the net expense. The sensitivity of these obligations and the net expense to changes in the key assumptions are outlined in Note 29.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

5. CHANGE IN ACCOUNTING POLICIES

The following tables reconcile the consolidated financial statements previously reported under IFRS to the restated consolidated financial statements as a result of the changes in accounting policies described in Note 3. Explanations of the effect of the new or amended IFRS follow the reconciliations.

RECONCILIATION OF THE CONSOLIDATED BALANCE SHEET
JANUARY 1, 2012

(millions of Canadian Dollars)	Note	Previously Reported	Change in Accounting Policies Joint Ventures	Restated
ASSETS				
Current assets				
Cash and cash equivalents		**613**	(27)	**586**
Accounts receivable		**421**	(14)	**407**
Finance lease receivables	b	**14**	(8)	**6**
Inventories		**82**	(3)	**79**
Prepaid expenses and other current assets		**52**	(7)	**45**
		1,182	(59)	**1,123**
Non-current assets				
Property, plant and equipment	a	**9,470**	(107)	**9,363**
Intangibles		**291**	-	**291**
Investment in ATCO Structures & Logistics		**152**	-	**152**
Investment in joint ventures		**-**	139	**139**
Finance lease receivables	b	**531**	(185)	**346**
Other assets		**70**	(1)	**69**
Total assets		**11,696**	(213)	**11,483**
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities		**542**	(15)	**527**
Asset retirement obligations and other provisions		**43**	-	**43**
Other current liabilities		**38**	(2)	**36**
Long-term debt		**139**	-	**139**
Non-recourse long-term debt	c	**40**	(16)	**24**
		802	(33)	**769**
Non-current liabilities				
Deferred income tax liabilities		**440**	(13)	**427**
Asset retirement obligations and other provisions		**187**	(9)	**178**
Retirement benefit obligations		**389**	(1)	**388**
Deferred revenues		**1,024**	-	**1,024**
Other liabilities		**117**	(4)	**113**
Long-term debt		**4,213**	-	**4,213**
Non-recourse long-term debt	c	**338**	(153)	**185**
Total liabilities		**7,510**	(213)	**7,297**
EQUITY				
Equity preferred shares		**724**	-	**724**
Equity preferred shares of subsidiary company		**343**	-	**343**
Class A and Class B share owners' equity				
Class A and Class B shares		**621**	-	**621**
Contributed surplus		**1**	-	**1**
Retained earnings		**2,508**	-	**2,508**
Accumulated other comprehensive income		**(11)**	-	**(11)**
		3,119	-	**3,119**
Total equity		**4,186**	-	**4,186**
Total liabilities and equity		**11,696**	(213)	**11,483**

RECONCILIATION OF THE CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2012

(millions of Canadian Dollars)	Note	Previously Reported	Change in Accounting Policies: Joint Ventures	Change in Accounting Policies: Retirement Benefits	Restated
ASSETS					
Current assets					
Cash and cash equivalents		**382**	(33)	-	**349**
Accounts receivable		**540**	(10)	-	**530**
Finance lease receivables	b	**16**	(9)	-	**7**
Inventories		**83**	(4)	-	**79**
Prepaid expenses and other current assets		**63**	(4)	-	**59**
		1,084	(60)	-	**1,024**
Non-current assets					
Property, plant and equipment	a	**11,237**	(91)	7	**11,153**
Intangibles		**330**	(1)	-	**329**
Investment in ATCO Structures & Logistics		**174**	-	-	**174**
Investment in joint ventures		**-**	140	-	**140**
Finance lease receivables	b	**515**	(175)	-	**340**
Other assets		**58**	-	-	**58**
Total assets		**13,398**	(187)	7	**13,218**
LIABILITIES					
Current liabilities					
Accounts payable and accrued liabilities		**793**	(8)	-	**785**
Asset retirement obligations and other provisions		**43**	-	-	**43**
Other current liabilities		**18**	(3)	-	**15**
Long-term debt		**4**	-	-	**4**
Non-recourse long-term debt	c	**44**	(14)	-	**30**
		902	(25)	-	**877**
Non-current liabilities					
Deferred income tax liabilities		**470**	(8)	2	**464**
Asset retirement obligations and other provisions		**198**	(11)	-	**187**
Retirement benefit obligations		**583**	-	-	**583**
Deferred revenues		**1,170**	-	-	**1,170**
Other liabilities		**127**	(4)	-	**123**
Long-term debt		**5,284**	-	-	**5,284**
Non-recourse long-term debt	c	**295**	(139)	-	**156**
Total liabilities		**9,029**	(187)	2	**8,844**
EQUITY					
Equity preferred shares		**723**	-	-	**723**
Equity preferred shares of subsidiary company		**343**	-	-	**343**
Class A and Class B share owners' equity					
Class A and Class B shares		**667**	-	-	**667**
Contributed surplus		**15**	-	-	**15**
Retained earnings		**2,637**	-	5	**2,642**
Accumulated other comprehensive income		**(16)**	-	-	**(16)**
		3,303	-	5	**3,308**
Total equity		**4,369**	-	5	**4,374**
Total liabilities and equity		**13,398**	(187)	7	**13,218**

RECONCILIATION OF THE CONSOLIDATED STATEMENT OF EARNINGS
YEAR ENDED DECEMBER 31, 2012

(millions of Canadian Dollars except per share data)	Previously Reported	Change in Accounting Policies: Joint Ventures	Change in Accounting Policies: Retirement Benefits	Restated
Revenues	**3,139**	(100)	-	**3,039**
Costs and expenses				
Salaries, wages and benefits	**(464)**	8	1	**(455)**
Energy transmission and transportation	**(126)**	-	-	**(126)**
Plant and equipment maintenance	**(255)**	13	-	**(242)**
Fuel costs	**(304)**	36	-	**(268)**
Purchased power	**(67)**	-	-	**(67)**
Materials and consumables	**(38)**	-	-	**(38)**
Depreciation, amortization and impairment	**(430)**	18	-	**(412)**
Franchise fees	**(161)**	-	-	**(161)**
Property and other taxes	**(86)**	-	-	**(86)**
Other	**(247)**	13	-	**(234)**
	(2,178)	88	1	**(2,089)**
	961	(12)	1	**950**
Earnings from investment in ATCO Structures & Logistics	**32**	-	-	**32**
Earnings from investment in joint ventures	**-**	2	-	**2**
Operating profit	**993**	(10)	1	**984**
Interest income	**13**	-	-	**13**
Interest expense	**(268)**	11	(12)	**(269)**
Net finance costs	**(255)**	11	(12)	**(256)**
Earnings before income taxes	**738**	1	(11)	**728**
Income taxes	**(158)**	(1)	3	**(156)**
Earnings for the year	**580**	-	(8)	**572**
Earnings attributable to:				
Equity owners of the Company	**561**	-	(8)	**553**
Equity preferred share owners of subsidiary company	**19**	-	-	**19**
	580	-	(8)	**572**
Earnings per Class A and Class B share	**$ 2.06**	$ -	$ (0.03)	**$ 2.03**
Diluted earnings per Class A and Class B share	**$ 2.05**	$ -	$ (0.03)	**$ 2.02**

RECONCILIATION OF THE CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME YEAR ENDED DECEMBER 31, 2012

	2012
Comprehensive income as previously reported	412
Change in accounting policy for retirement benefits:	
Earnings for the period	(8)
Other comprehensive income	13
Comprehensive income restated	417
Comprehensive income attributable to:	
Equity owners of the Company	398
Equity preferred share owners of subsidiary Company	19
	417

RECONCILIATION OF THE CONSOLIDATED STATEMENT OF CHANGES IN EQUITY DECEMBER 31, 2012

	December 31 2012
Equity as previously reported	4,369
Change in accounting policy for retirement benefits:	
Earnings for the period	(8)
Other comprehensive income	13
Equity restated	4,374

RECONCILIATION OF THE CONSOLIDATED STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2012

(millions of Canadian Dollars)	Previously Reported	Change in Accounting Policies: Joint Ventures	Change in Accounting Policies: Retirement Benefits	Restated
Operating activities				
Earnings for the year	**580**	-	(8)	**572**
Adjustments for:				
Depreciation, amortization and impairment	**430**	(18)	-	**412**
Earnings from investment in ATCO Structures & Logistics	**(32)**	-	-	**(32)**
Dividends received from ATCO Structures & Logistics	**7**	-	-	**7**
Earnings from investment in joint ventures	**-**	(2)	-	**(2)**
Dividends and distributions received from joint ventures	**-**	3	-	**3**
Income taxes	**158**	1	(3)	**156**
Unearned availability incentives	**10**	-	-	**10**
Contributions by customers for extensions to plant	**184**	-	-	**184**
Amortization of customer contributions	**(43)**	-	-	**(43)**
Net finance costs	**255**	(11)	12	**256**
Income taxes paid	**(94)**	4	-	**(90)**
Other	**28**	(11)	(1)	**16**
	1,483	(34)	-	**1,449**
Changes in non-cash working capital	**(99)**	2	-	**(97)**
Cash flow from operations	**1,384**	(32)	-	**1,352**
Investing activities				
Additions to property, plant and equipment	**(2,149)**	-	-	**(2,149)**
Proceeds on disposal of property, plant and equipment	**7**	-	-	**7**
Additions to intangibles	**(73)**	-	-	**(73)**
Changes in non-cash working capital	**231**	-	-	**231**
Other	**(8)**	-	-	**(8)**
	(1,992)	-	-	**(1,992)**
Financing activities				
Issue of long-term debt	**1,311**	-	-	**1,311**
Repayment of long-term debt	**(364)**	-	-	**(364)**
Repayment of non-recourse long-term debt	**(40)**	16	-	**(24)**
Issue of equity preferred shares	**300**	-	-	**300**
Redemption of equity preferred shares	**(300)**	-	-	**(300)**
Issue of Class A shares	**2**	-	-	**2**
Dividends paid on equity preferred shares	**(35)**	-	-	**(35)**
Dividends paid on equity preferred shares of subsidiary company	**(19)**	-	-	**(19)**
Dividends paid to Class A and Class B share owners	**(168)**	-	-	**(168)**
Interest paid	**(297)**	11	-	**(286)**
Other	**(14)**	-	-	**(14)**
	376	27	-	**403**
Foreign currency translation	**1**	(1)	-	**-**
Cash position				
Decrease	**(231)**	(6)	-	**(237)**
Beginning of year	**613**	(27)	-	**586**
End of year	**382**	(33)	-	**349**

EXPLANATIONS OF THE EFFECT OF IFRS 11 AND IAS 19

a) Property, Plant and Equipment

The adoption of IAS 19 increased property, plant and equipment by $7 million for the year ended December 31, 2012, due to increased employee costs that were directly attributable to the construction of assets. Each class of property, plant and equipment has been restated as at January 1, 2012, and December 31, 2012, in Note 13 as a result of the adoption of IFRS 11 and IAS 19.

b) Finance Lease Receivables

Certain power generation assets relating to the Brighton Beach Plant were previously reported as a finance lease receivable. Under IFRS 11, the carrying amount of the finance lease receivable of $193 million and $184 million as at January 1, 2012, and December 31, 2012, has been restated and reported in the net investment in joint ventures.

c) Non-Recourse Long-Term Debt

Under IFRS 11, the non-recourse debt listed below has been restated and reported in the net investment in joint ventures as at January 1, 2012, and December 31, 2012.

Project Financing	**Effective Interest Rate**	**December 31 2012**	**January 1 2012**
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013			
$4 million AUD (January 1, 2012 – $11 million AUD)	Floating	5	11
Brighton Beach:			
Term loan, at BA rates, due to 2020	Floating	17	19
Term loan, at LIBOR, due to 2020	Floating	15	18
Construction overrun facility, at BA rates, due to 2020	Floating	4	4
Construction overrun facility, at LIBOR, due to 2020	Floating	4	4
Notes, at fixed rate of 6.924%, due to 2024	7.025%	109	114
Less: Deferred financing charges		(1)	(1)
		153	169

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

RETIREMENT BENEFITS PRO-FORMA RESULTS
YEAR ENDED DECEMBER 31, 2013

If the Company had not adopted IAS 19, the impact on the consolidated financial statements for the year ended December 31, 2013, would have been:

	Pro-forma Year Ended December 31, 2013
Consolidated Statement of Earnings and Comprehensive Income	
Increase (decrease) in earnings for the year:	
Salaries, wages and benefits	**3**
Interest expense	**14**
Income taxes	**(4)**
Earnings for the year	**13**
Decrease in other comprehensive income for the year:	
Retirement benefits	**(21)**
Comprehensive income for the year	**(8)**
Increase in earnings per Class A and Class B share	**$0.05**
Increase in diluted earnings per Class A and Class B share	**$0.05**
Consolidated Statement of Cash Flows	
Increase (decrease) in cash flow from operations:	
Earnings for the year	**13**
Income taxes	**4**
Net finance costs	**(14)**
Other	**(3)**

	Pro-forma December 31, 2013
Consolidated Balance Sheet	
Decrease in assets:	
Property, plant and equipment	**(11)**
Decrease in liabilities and equity:	
Deferred income tax liabilities	**(3)**
Retained earnings	**(8)**
	(11)

The expected long-term rate of return on plan assets for the year for the registered group defined benefit plans is assumed to have been 5.9%. This rate of return was 1.6% above the liability discount rate for the year of 4.3% due to the equity and management premium.

6. SEGMENTED INFORMATION

DESCRIPTION OF SEGMENTS

Utilities	The Utilities' activities are conducted through three regulated businesses within western and northern Canada: ATCO Electric, ATCO Gas and ATCO Pipelines. ATCO Electric and its subsidiaries, The Yukon Electrical Company, Northland Utilities (NWT) and Northland Utilities (Yellowknife) transmit and distribute electricity mainly in northern and central east Alberta, the Yukon and Northwest Territories. Its service territory includes the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River. ATCO Gas distributes natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. It services municipal, residential, business and industrial customers. ATCO Pipelines transmits natural gas in Alberta. This business receives natural gas on its pipeline system at various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province or to other pipeline systems, primarily for export out of the province.
Energy	Energy's activities are conducted through ATCO Power and ATCO Energy Solutions. ATCO Power's businesses include the non-regulated supply of electricity from natural gas and hydro-power generating plants in western Canada, Ontario and the U.K. ATCO Power's businesses also include the regulated supply of electricity from coal-fired generating plants in Alberta. ATCO Energy Solutions' businesses include non-regulated natural gas gathering, processing, storage and transmission, natural gas liquids extraction, electricity transmission and industrial water services.
ATCO Australia	ATCO Australia consists of three distinct business operations: ATCO Gas Australia, ATCO Power Australia and ATCO I-Tek Australia. ATCO Gas Australia is a regulated provider of natural gas distribution services in western Australia. It serves metropolitan Perth and surrounding regions. ATCO Power Australia supplies electricity from three natural gas-fired generation plants in Adelaide, South Australia; Brisbane, Queensland; and Karratha, Western Australia. Additionally, the Bulwer Island plant in Brisbane provides cogeneration steam and the Osborne plant in Adelaide provides steam independent of the power plant through auxiliary boiler assets. ATCO I-Tek Australia supplies information technology services mainly to ATCO Gas Australia and Dampier Bunbury Pipelines.
Corporate and Other	The Corporate and Other segment includes ATCO I-Tek and commercial real estate the Company owns in Alberta. ATCO I-Tek develops, operates and supports information systems and technologies, and also provides billing services, payment processing, credit, collection, and call centre services.

The Company's operating segments are reported in the same way as internal reporting provided to the CODM. The accounting policies applied by the segments are the same as those applied by the Company. Intersegment transactions are measured at the exchange amount, which is the consideration agreed to by the related parties.

SEGMENTED RESULTS
YEAR ENDED DECEMBER 31

2013 / 2012	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**2,035**	**1,011**	**261**	**74**	**–**	**3,381**
	1,842	878	251	68	–	3,039
Revenues – intersegment	**5**	**6**	**–**	**162**	**(173)**	**–**
	2	4	–	166	(172)	–
Revenues	**2,040**	**1,017**	**261**	**236**	**(173)**	**3,381**
	1,844	882	251	234	(172)	3,039
Operating expenses (1)	**(1,044)**	**(689)**	**(123)**	**(174)**	**176**	**(1,854)**
	(971)	(569)	(127)	(179)	169	(1,677)
Depreciation, amortization and impairment (2)	**(320)**	**(107)**	**(38)**	**(16)**	**3**	**(478)**
	(277)	(86)	(36)	(16)	3	(412)
Earnings from investment in ATCO Structures & Logistics (3)	**–**	**–**	**–**	**41**	**–**	**41**
	–	–	–	32	–	32
Earnings from investment in joint ventures (2)	**–**	**(29)**	**5**	**–**	**–**	**(24)**
	–	(5)	7	–	–	2
Net finance costs	**(178)**	**(33)**	**(61)**	**7**	**(8)**	**(273)**
	(160)	(36)	(63)	9	(6)	(256)
Earnings before income taxes	**498**	**159**	**44**	**94**	**(2)**	**793**
	436	186	32	80	(6)	728
Income taxes	**(126)**	**(52)**	**(8)**	**(1)**	**–**	**(187)**
	(106)	(49)	(6)	3	2	(156)
Earnings for the year	**372**	**107**	**36**	**93**	**(2)**	**606**
	330	137	26	83	(4)	572
Adjusted earnings	**338**	**151**	**45**	**38**	**–**	**572**
	282	136	43	52	2	515
Total assets (4)	**11,611**	**1,619**	**1,296**	**602**	**(77)**	**15,051**
	9,871	1,741	1,335	330	(59)	13,218
Total liabilities (4)	**7,724**	**1,000**	**935**	**122**	**(124)**	**9,657**
	6,533	1,057	988	114	152	8,844
Capital expenditures (5)	**2,178**	**68**	**89**	**63**	**–**	**2,398**
	2,142	42	74	14	–	2,272

(1) *Includes total costs and expenses excluding depreciation, amortization and impairment expense.*

(2) *Includes impairment of property, plant and equipment (see Note 13) and investment in joint venture (see Note 16).*

(3) *Includes ATCO Structures & Logistics' gain on sale of Tecno Fast ATCO S.A. (see Note 15).*

(4) *Total assets and total liabilities do not reflect adjustments for rate-regulated activities included in adjusted earnings.*

(5) *Includes additions to property, plant and equipment and intangibles and $65 million (2012 – $50 million) of interest capitalized during construction for the year ended December 31, 2013.*

GEOGRAPHIC SEGMENTS

Revenues - external [1]

	2013	2012
Canada	**3,120**	2,787
Australia	**261**	251
United Kingdom	**–**	1
Total	**3,381**	3,039

(1) *Revenues are attributed based on the country in which the good or service originated.*

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets [2]		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
Canada	**11,917**	10,137	**355**	311	**256**	238	**12,528**	10,686
Australia	**983**	1,016	**15**	18	**40**	43	**1,038**	1,077
United Kingdom	**5**	–	**–**	–	**28**	64	**33**	64
Total	**12,905**	11,153	**370**	329	**324**	345	**13,599**	11,827

(2) *Excludes financial instruments and deferred income tax assets.*

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses for rate-regulated activities and dividends on equity preferred shares of the Company. Adjusted earnings also exclude one-time gains and losses, significant impairments and items that are not in the normal course of business or a result of day-to-day operations. Adjusted earnings are a key measure of segment earnings used by the CODM to assess segment performance and allocate resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31, 2013 is below.

2013 2012	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Adjusted earnings	**338**	**151**	**45**	**38**	**–**	**572**
	282	136	43	52	2	515
Gain and loss on asset sales	**–**	**–**	**–**	**14**	**–**	**14**
	–	–	–	–	–	–
Impairments	**–**	**(45)**	**(2)**	**–**	**–**	**(47)**
	–	–	–	–	–	–
Adjustments for rate-regulated activities	**12**	**–**	**(7)**	**–**	**(2)**	**3**
	26	–	(17)	–	(6)	3
Dividends on equity preferred shares of Canadian Utilities Limited	**3**	**1**	**–**	**41**	**–**	**45**
	3	1	–	31	–	35
Earnings attributable to equity owners of the Company	**353**	**107**	**36**	**93**	**(2)**	**587**
	311	137	26	83	(4)	553
Earnings attributable to equity preferred share owners of subsidiary						**19**
						19
Earnings for the year						**606**
						572

Gain and loss on asset sales

The Company has adjusted for its $15 million share of the realized gain on sale of Tecno Fast ATCO S.A. and its $1 million share of the loss on sale of U.K. rental fleet assets. These items are included in equity earnings from investment in ATCO Structures and Logistics (see Note 15).

Impairments

The Company has adjusted for significant impairments of certain natural gas gathering, processing and liquids extraction assets in Canada. These impairments were included in depreciation, amortization and impairment expense (see Note 13). The Company also adjusted for a significant impairment of its joint venture power generation assets in the U.K., as well as an impairment of its power generation assets in Australia. These impairments were recognized as reductions of equity earnings from investment in joint ventures (see Note 16).

Adjustments for rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. Consequently, the Company does not recognize assets and liabilities arising from rate-regulated activities under IFRS.

Prior to the adoption of IFRS, the Company used standards issued by the Financial Accounting Standards Board (FASB) in the United States (U.S.) as another source of generally accepted accounting principles (GAAP) to account for rate-regulated activities. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of its rate-regulated activities. Therefore, the Company presents adjusted earnings as part of the Company's segment disclosures on this basis.

Rate-regulated accounting differs from IFRS in the following ways:

	Rate-Regulated Accounting Treatment	IFRS Treatment
1.	The Company defers the recognition of cash received in advance of future expenditures.	The Company records revenues when amounts are billed to customers and recognizes costs when they are incurred.
2.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings.
3.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company recognizes earnings when customer rates are changed and amounts are billed to customers.
4.	Intercompany profits on the manufacture or construction of facilities for a regulated public utility in the consolidated group are deemed to have been realized to the extent that the transfer price on such facilities is recognized for rate-making purposes by a regulator.	Intercompany profits are eliminated upon consolidation. The Company then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

Timing adjustments for rate-regulated activities are as follows:

	2013	2012
Additional revenues billed in current period:		
Future removal and site restoration costs (1)	**40**	33
Retirement benefits (2)	**5**	13
Finance costs on major transmission capital projects (3)	**39**	27
Transmission capital deferral (6)	**–**	26
Other	**1**	4
	85	103
Revenues to be billed in future period:		
Deferred income taxes (4)	**(73)**	(51)
Transmission access payments (5)	**(46)**	(21)
Transmission capital deferral (6)	**(14)**	–
Impact of warmer temperatures on revenues (7)	**–**	(2)
Impact of inflation on rate base for ATCO Gas Australia (8)	**(16)**	(13)
Other	**(14)**	(17)
	(163)	(104)
Regulatory decisions related to current and prior periods:		
Transmission access payments recoveries (9)	**65**	40
ATCO Gas Australia appeal decision (9)	**9**	(4)
Weather recoveries (refunds) (7)	**4**	(7)
Other	**10**	(16)
	88	13
Intercompany profits:		
Intercompany profits related to construction of property, plant and equipment and intangibles (10)	**(7)**	(9)
	3	3

Descriptions of the adjustments, and the timing of recovery or refund for each, are as follows:

	Description	Timing of Recovery or Refund
1.	Future removal and site restoration costs are billed to customers on a forecast basis over the life of the associated assets. Under rate-regulated accounting, billings to customers in excess of costs incurred in the current period are deferred.	The deferred revenues will be recognized in adjusted earnings when removal and site restoration costs are incurred.
2.	Contributions to defined benefit pension plans and OPEB plans are billed to customers when paid by the Company, whereas the costs of retirement benefits are accrued over the service life of the employees. Under rate-regulated accounting, contributions paid and billed to customers in excess of costs accrued in the current period are deferred.	The deferred revenues will be recognized in adjusted earnings as the variances between contributions and costs reverse over the life of the plans.
3.	Finance costs incurred by ATCO Electric on major transmission capital projects during the course of construction are billed to customers when incurred. Under rate-regulated accounting, the finance costs billed to customers are deferred.	The deferred revenues will be recognized in adjusted earnings over the service life of the related assets.

	Description	Timing of Recovery or Refund
4.	Deferred income taxes are a non-cash expense incurred by the Company on temporary differences between the book value and the tax value of assets and liabilities. Unless directed by the regulator, deferred income taxes are not billed to customers until income taxes are paid by the Company. Under rate-regulated accounting, revenues are recognized in the current period for the deferred income taxes to be billed to customers in future periods.	The revenues will reverse when the temporary differences that gave rise to the deferred income taxes reverse in future periods.
5.	Transmission access payments are billed to customers by ATCO Electric on a forecast basis, whereas the payments are expensed when incurred. Under rate-regulated accounting, differences between actual costs incurred and forecast costs billed to customers are deferred for collection from or refund to customers in future periods.	Recoveries from or refunds to customers of the differences between transmission access payments billed to customers and paid by ATCO Electric are expected to occur in the next 6 to 12 months.
6.	For major transmission capital projects, ATCO Electric's billings to customers include a return on forecast rate base. When actual capital costs vary from forecast capital costs, the return on rate base, and the resulting billings to the Alberta Electric System Operator (AESO), will be higher or lower than expected. Under rate-regulated accounting, differences between billings to the AESO and the return on actual rate base are deferred.	Recoveries from or refunds to the AESO of variances between forecast and actual returns on rate base are expected to occur in the following year.
7.	ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Under rate-regulated accounting, revenues above or below the norm are deferred and refunded to or recovered from customers in future periods.	ATCO Gas may apply to the AUC for recoveries from or refunds to customers when the net revenue variances exceed $7 million at April 30th of any year for either of its North or South systems.
8.	ATCO Gas Australia earns a return on rate base that excludes inflation. Inflation is accounted for by adjusting the rate base in subsequent periods by the actual rate of inflation; the impact of inflation is billed to customers through recovery of depreciation. Under rate-regulated accounting, an adjustment is made to recognize the inflation component of rate base when it is earned in the current period. Differences between the amounts earned and the amounts billed to customers are deferred.	The inflation-indexed portion of rate base will be recovered from customers over the life of the assets comprising rate base through the recovery of depreciation.

	Description	Timing of Recovery or Refund
9.	The Canadian and Australian utilities recognize revenues from regulatory decisions when customer rates are changed and amounts are billed to customers. Under rate-regulated accounting, revenues from regulatory decisions that affect current and prior periods are recognized when the decision is received.	In June 2012, the Australian Competition Tribunal (ACT) issued a decision on ATCO Gas Australia's appeal of an earlier ERA decision for the current Access Arrangement. As a result of the ACT's decision, the ERA amended its decision and ATCO Gas Australia recorded adjusted earnings of $10 million in the second quarter of 2012 representing the period from January 1, 2010, to June 30, 2012. The remaining $8 million will be recognized in adjusted earnings over the remaining period of the Access Arrangement to June 30, 2014. These earnings are recognized under IFRS when customers are billed over the remaining 24 months of the Access Arrangement starting in July 2012. In the years ended December 31, 2013 and 2012, actual payments for transmission access paid by ATCO Electric exceeded forecast costs included in billings to customers. These excess costs are subsequently recovered from customers.
10.	Under rate-regulated accounting, intercompany profits from transactions with related parties and approved by the regulator for inclusion in rate base are not eliminated on consolidation; they are recognized as earnings in the current period.	Intercompany profits will be recognized as earnings under IFRS as rate base is depreciated and the depreciation is billed to customers over the life of the assets.

7. REVENUES

	2013	2012
Sale of goods	**662**	559
Rendering of services	**2,384**	2,187
Operating lease income	**300**	254
Finance lease income	**35**	39
	3,381	3,039

8. OTHER COSTS AND EXPENSES

	2013	2012
Goods and services (1)	**216**	195
Rent and utilities	**44**	42
PPA arbitration decision	**17**	–
Realized (gains) losses on derivatives	**6**	(4)
Unrealized (gains) losses on derivatives	**(5)**	1
	278	234

(1) *Goods and services include professional fees, contractor costs, technology related expenses, advertising, and other general and administrative expenses.*

9. INCOME TAXES

The components of income tax expense are summarized below.

	2013	2012
Current income tax expense:		
Canada	**74**	74
Australia	**1**	4
Adjustment in respect of prior years	**1**	(6)
	76	72
Deferred income tax expense:		
Reversal of temporary differences	**111**	86
Adjustment in respect of prior years	**–**	(2)
	111	84
	187	156

The reconciliation of statutory and effective income tax expense is as follows:

	2013		2012	
Earnings before income taxes	**793**	**%**	728	%
Income taxes, at statutory rates	**198**	**25.0**	182	25.0
Equity earnings	**(2)**	**(0.2)**	(7)	(1.0)
International financing	**(14)**	**(1.8)**	(14)	(1.9)
Other	**5**	**0.6**	(5)	(0.7)
	187	**23.6**	156	21.4

The combined Federal and Alberta statutory Canadian income tax rate did not change from 2012 to 2013. Changes in tax rates in foreign jurisdictions were not material.

The changes in deferred income tax assets and liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carryforwards and Tax Credits	Retirement Benefit Obligations	Other	Total
Deferred income tax assets:							
January 1, 2012	(26)	(8)	46	2	2	5	21
Credit (charge) to earnings	5	4	3	3	1	(6)	10
Charge to other comprehensive income	–	–	(9)	–	–	–	(9)
Other	–	–	–	–	–	4	4
December 31, 2012	**(21)**	**(4)**	**40**	**5**	**3**	**3**	**26**
Credit (charge) to earnings	**4**	**–**	**(6)**	**3**	**–**	**(1)**	**–**
Other	**–**	**–**	**1**	**3**	**–**	**(2)**	**2**
December 31, 2013	**(17)**	**(4)**	**35**	**11**	**3**	**–**	**28**
Deferred income tax liabilities:							
January 1, 2012	553	39	(28)	(9)	(131)	3	427
Charge (credit) to earnings	96	6	(3)	7	–	(12)	94
Credit to other comprehensive income	–	–	(10)	–	(50)	–	(60)
Other	–	–	–	–		3	3
December 31, 2012	**649**	**45**	**(41)**	**(2)**	**(181)**	**(6)**	**464**
Charge (credit) to earnings	**112**	**–**	**7**	**(13)**	**4**	**1**	**111**
Charge (credit) to other comprehensive income	**–**	**–**	**5**	**–**	**76**	**(1)**	**80**
Other	**(2)**	**–**	**–**	**–**	**–**	**(2)**	**(4)**
December 31, 2013	**759**	**45**	**(29)**	**(15)**	**(101)**	**(8)**	**651**

The Company does not expect any of its deferred income tax assets or liabilities to reverse within the next 12 months.

At the balance sheet date, the Company had $105 million in tax losses and credits, which, if unused, expire on the following dates:

	Non-Capital Losses
2031	18
2032	17
2033	57
Do not expire	13

The Company recorded deferred income tax assets of $23 million for losses and credits that expire. No deferred income tax assets are recorded for losses that do not expire.

The Company recorded deferred income tax assets of $3 million (2012 – $3 million) directly to equity.

The Company has $34 million (2012 – $31 million) of aggregate temporary differences for investments in subsidiaries, branches and joint ventures for which deferred income tax liabilities have not been recognized. Deferred income taxes not recognized at the balance sheet date are $8 million (2012 – $8 million).

10. OTHER COMPREHENSIVE INCOME

Other comprehensive income (OCI) is comprised of: gains and losses on retirement benefit plan assets and obligations; the unrealized gains and losses on effective cash flow hedging instruments; the foreign currency translation adjustment (FCTA) relating to foreign operations; and OCI related to the Company's equity investment in ATCO Structures & Logistics (ASL) and joint ventures.

Changes in the components of accumulated OCI are summarized below.

	Retirement Benefits	Cash Flow Hedges	FCTA	Share of OCI of ASL	Share of OCI of Joint Ventures	Total
January 1, 2012	–	(11)	4	1	(5)	(11)
OCI for the year before income taxes	(199)	(4)	(2)	(3)	2	(206)
Income tax expense	50	1	–	–	–	51
	(149)	(3)	(2)	(3)	2	(155)
Transferred to retained earnings	149	–	–	1	–	150
December 31, 2012	**–**	**(14)**	**2**	**(1)**	**(3)**	**(16)**
OCI for the year before income taxes	**299**	**14**	**(30)**	**(1)**	**(2)**	**280**
Income tax recovery (expense)	**(76)**	**(5)**	**–**	**–**	**1**	**(80)**
	223	**9**	**(30)**	**(1)**	**(1)**	**200**
Transferred to retained earnings	**(223)**	**–**	**–**	**(2)**	**2**	**(223)**
December 31, 2013	**–**	**(5)**	**(28)**	**(4)**	**(2)**	**(39)**

11. LEASES

THE COMPANY AS LESSOR

Finance leases

The total net investment in finance leases is shown below. Finance lease income is recognized in revenue.

	2013	2012
Net investment in finance leases:		
Finance lease - gross investment	**735**	811
Unearned finance income	**(411)**	(467)
Unguaranteed residual value	**3**	3
	327	347
Current portion	**8**	7
Non-current portion	**319**	340
	327	347
Gross receivables from finance leases:		
In one year or less	**45**	47
In more than one year, but not more than five years	**183**	190
In more than five years	**507**	574
	735	811
Net investment in finance leases:		
In one year or less	**8**	7
In more than one year, but not more than five years	**44**	41
In more than five years	**275**	299
	327	347

During the year ended December 31, 2013, $4 million (2012 – $4 million) of contingent rents was recognized as income from these finance leases.

Operating leases

Operating leases include PPAs classified as operating leases and other property rentals. The aggregate future minimum lease payments receivable under these non-cancellable operating leases are:

	2013	2012
Minimum lease payments receivable:		
In one year or less	**150**	215
In more than one year, but not more than five years	**630**	605
In more than five years	**327**	477
	1,107	1,297

During the year ended December 31, 2013, $60 million (2012 – $23 million) of contingent rents was recognized as income from these operating leases.

THE COMPANY AS LESSEE

Operating leases

The Company's operating leases are comprised primarily of long-term leases for office premises and equipment.

During the year ended December 31, 2013, $36 million (2012 – $38 million) was recognized as an expense for these operating leases. No sublease payments were received or made, nor were any contingent rental payments made, for these operating leases.

12. INVENTORIES

	2013	2012
Natural gas and fuel in storage	**21**	22
Raw materials and consumables	**68**	56
Work-in-progress	**1**	1
	90	79

For the year ended December 31, 2013, inventories recognized as an expense was $102 million (2012 – $60 million). Write-downs to net realizable value were less than $1 million in 2013 and 2012 and there were no reversals of previous write-downs to net realizable value.

No inventories are pledged as security for liabilities.

13. PROPERTY, PLANT AND EQUIPMENT

	Utility Transmission & Distribution	Power Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost:						
January 1, 2012	9,520	1,941	314	763	827	13,365
Additions	1,255	20	170	662	84	2,191
Disposals	(50)	(19)	–	–	(28)	(97)
Changes to asset retirement costs	–	1	–	–	5	6
Foreign exchange rate adjustment	(6)	–	–	–	–	(6)
December 31, 2012	**10,719**	**1,943**	**484**	**1,425**	**888**	**15,459**
Additions	**1,809**	**41**	**75**	**220**	**171**	**2,316**
Disposals	**(60)**	**(9)**	**(2)**	**–**	**(29)**	**(100)**
Changes to asset retirement costs	**–**	**(7)**	**–**	**–**	**(27)**	**(34)**
Foreign exchange rate adjustment	**(84)**	**–**	**–**	**(2)**	**(2)**	**(88)**
December 31, 2013	**12,384**	**1,968**	**557**	**1,643**	**1,001**	**17,553**
Accumulated depreciation:						
January 1, 2012	2,469	1,052	93	–	388	4,002
Depreciation and impairment	259	61	10	–	60	390
Disposals	(50)	(15)	–	–	(21)	(86)
December 31, 2012	**2,678**	**1,098**	**103**	**–**	**427**	**4,306**
Depreciation and impairment	**280**	**63**	**16**	**–**	**86**	**445**
Disposals	**(60)**	**(8)**	**(2)**	**–**	**(28)**	**(98)**
Foreign exchange rate adjustment	**(4)**	**–**	**–**	**–**	**(1)**	**(5)**
December 31, 2013	**2,894**	**1,153**	**117**	**–**	**484**	**4,648**
Net book value:						
January 1, 2012	7,051	889	221	763	439	9,363
December 31, 2012	8,041	845	381	1,425	461	11,153
December 31, 2013	**9,490**	**815**	**440**	**1,643**	**517**	**12,905**

Included in the cost of property, plant and equipment is $65 million (2012 – $50 million) of interest capitalized. Interest was capitalized at the rate of interest applicable to the specific borrowings financing the assets under construction or, where financed through general borrowings, at a capitalization rate representing the average interest rate on borrowings. Interest rates ranged from 5.34% to 7.00% (2012 – 5.55% to 6.37%).

In the fourth quarter of 2013, the Company recognized a pre-tax impairment of $16 million relating to certain natural gas gathering, processing and liquids extraction plants (Energy segment), which was included in depreciation, amortization and impairment expense. The anticipated price and recovery of natural gas liquids have not materialized as the market has re-focused on a different geographical area. Management made assumptions about gas volumes, the price of natural gas liquids and operational capacity based on industry information and company forecasts to project expected future cash flows. The cash flows were discounted at a pre-tax rate of 9.25%. After recognizing this impairment, the recoverable amount of these assets was $21 million at December 31, 2013. This amount was determined using value in use.

Property, plant and equipment with a carrying value of $355 million were pledged as security for liabilities at December 31, 2013 (2012 – $372 million).

14. INTANGIBLES

	Computer Software	Land Rights	Other	Total
Cost:				
January 1, 2012	368	145	17	530
Additions	49	13	12	74
Disposals	(23)	–	–	(23)
December 31, 2012	**394**	**158**	**29**	**581**
Additions	**43**	**39**	**5**	**87**
Disposals	**(5)**	**–**	**–**	**(5)**
Foreign exchange rate adjustment	**(2)**	**–**	**(1)**	**(3)**
December 31, 2013	**430**	**197**	**33**	**660**
Accumulated amortization:				
January 1, 2012	211	26	2	239
Amortization	26	2	2	30
Disposals	(17)	–	–	(17)
December 31, 2012	**220**	**28**	**4**	**252**
Amortization	**35**	**2**	**6**	**43**
Disposals	**(5)**	**–**	**–**	**(5)**
December 31, 2013	**250**	**30**	**10**	**290**
Net book value:				
January 1, 2012	157	119	15	291
December 31, 2012	174	130	25	329
December 31, 2013	**180**	**167**	**23**	**370**

15. INVESTMENT IN ATCO STRUCTURES & LOGISTICS

The Company has an ownership interest of 24.5% in ATCO Structures & Logistics, which has five divisions: Modular Structures, Logistics and Facility O&M Services, Lodging and Support Services, Emissions Management and Sustainable Communities.

The summarized financial information for ATCO Structures & Logistics, which is accounted for using the equity method, is provided below.

	2013	2012
Balance sheet:		
Current assets	**462**	303
Non-current assets	**501**	526
Current liabilities	**(192)**	(176)
Non-current liabilities	**(170)**	(118)
Net assets	**601**	535

	2013	2012
Statement of earnings and comprehensive income:		
Revenues	**1,004**	1,004
Earnings for the year	**169**	129
OCI	**(3)**	(10)
Comprehensive income for the year	**166**	119
Dividends received from ATCO Structures & Logistics	**24**	7

Reconciliation of the above summarized financial information to the carrying amount of the investment in ATCO Structures & Logistics recognized in the consolidated financial statements is as follows:

	2013	2012
Net assets	**601**	535
Proportion of the Company's ownership	**24.5%**	24.5%
	147	131
Fair value adjustment on acquisition	**43**	43
Carrying amount of the investment	**190**	174

On September 13, 2013, ATCO Structures & Logistics sold its 50% ownership interest in Tecno Fast ATCO S.A. for proceeds of $124 million cash. The Company's 24.5% share of the gain on sale contributed equity earnings of $15 million.

On November 1, 2013, ATCO Structures & Logistics sold its U.K. rental fleet assets for proceeds of $5 million cash, resulting in a loss of $3 million. The Company has recorded an equity loss of $1 million relating to this transaction.

16. JOINT ARRANGEMENTS

JOINT OPERATIONS

Significant joint operations included in the consolidated financial statements at December 31, 2013, are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership %	Principal Activity
Energy:			
Sheerness Generating Plant	Canada	50.0	Power generation
Joffre Cogeneration Plant	Canada	40.0	Power generation
Cory Cogeneration Plant	Canada	50.0	Power generation
Muskeg River Cogeneration Plant	Canada	70.0	Power generation

JOINT VENTURES

The following joint ventures are considered the most significant; however, they are not individually material to the operations of the Company.

Significant Joint Ventures	Operating Jurisdiction	Ownership %	Principal Activity
Energy:			
Brighton Beach Plant	Canada	50.0	Power generation
Barking Generating Plant	United Kingdom	25.5	Power generation
ATCO Australia:			
Osborne Cogeneration Plant	Australia	50.0	Power generation

Information for the Company's interest in joint ventures that are not individually material is aggregated below.

	2013	2012
Earnings for the year	**(24)**	2
OCI	**(1)**	2
Comprehensive income for the year	**(25)**	4
Aggregate carrying amount of interests in these joint ventures	**98**	140

IMPAIRMENT OF BARKING POWER LTD.

ATCO Power operates the 1,000 MW Barking generating plant in the U.K. and has an ownership interest of 25.5%. In the fourth quarter of 2013, the Company recognized an impairment of $33 million (2012 – $7 million) in equity earnings relating to the Barking plant (Energy segment). Ongoing weaknesses in the U.K. economy and an increase in competition from renewable energy due to significant regulatory changes has resulted in declining projected U.K. energy margins and continued losses for the Barking operations.

The recoverable amount of the Barking CGU was determined based on a value in use calculation. This calculation used pre-tax cash flow projections based on financial budgets approved by management covering a five-year period. In calculating the value in use, management was required to make assumptions about future capacity revenue, which included consideration of proposed regulatory changes. Capacity revenue forecasts beyond five years were based on independent long-term market forecasts and management's judgement for U.K. energy prices and volumes. The expected future cash flows were discounted at a pre-tax rate of 11%, which reflects the specific risks relating to the CGU. The estimated future growth rate of (1.9)% to 1.6% was based on management's assumptions. After recognizing this impairment, the recoverable amount of the CGU was $8 million at December 31, 2013, of which the majority is land.

COMMITMENTS

The joint ventures have contractual obligations in the normal course of business. The Company's share of these contractual obligations and the future minimum undiscounted contractual maturities are as follows:

	2014	2015	2016	2017	2018	2019 and thereafter
Non-recourse long-term debt	10	12	13	14	16	75
Interest expense	9	8	7	6	6	14
Operating and maintenance agreements	7	4	3	2	2	3
Derivatives	1	1	–	–	–	–
Other	1	–	–	–	–	–
	28	25	23	22	24	92

SIGNIFICANT RESTRICTIONS AND GUARANTEES

The Company requires approval from its joint venture partners before any dividends or distributions can be paid.

Reserve amounts have been set aside for major maintenance and debt servicing as stipulated in the Brighton Beach project financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. The obligations under these guarantees were less than $1 million at December 31, 2013 and 2012.

17. BANK INDEBTEDNESS AND LINES OF CREDIT

The Company has the following lines of credit that enable it to obtain financing for general business purposes:

			2013			2012
	Total	**Used**	**Available**	**Total**	**Used**	**Available**
Long-term committed	**2,227**	**453**	**1,774**	1,824	113	1,711
Short-term committed	**–**	**–**	**–**	26	17	9
Uncommitted	**53**	**2**	**51**	53	4	49
	2,280	**455**	**1,825**	1,903	134	1,769

Long-term committed credit facilities have maturities greater than one year. Short-term committed credit facilities mature in 365 days or less. Uncommitted credit facilities have no set maturity and the lender can demand repayment at any time.

Of the $455 million used at December 31, 2013, $2 million is current bank indebtedness, $397 million is long-term debt and $56 million represents outstanding letters of credit (2012 – $78 million is long-term debt and $56 million represents outstanding letters of credit).

18. ASSET RETIREMENT OBLIGATIONS AND OTHER PROVISIONS

	Asset Retirement Obligations	Other	Total
January 1, 2012	174	47	221
Additions	–	2	2
Utilized in the year	–	(4)	(4)
Accretion expense	4	–	4
Revisions in discount rate	7	–	7
December 31, 2012	**185**	**45**	**230**
Additions	**2**	**3**	**5**
Disposals	**(2)**	**–**	**(2)**
Utilized in the year	**(1)**	**(4)**	**(5)**
Accretion expense	**3**	**–**	**3**
Revisions in discount rate	**(36)**	**–**	**(36)**
Foreign exchange rate adjustment	**–**	**(3)**	**(3)**
December 31, 2013	**151**	**41**	**192**
Current	**15**	**40**	**55**
Non-current	**136**	**1**	**137**
	151	**41**	**192**

ASSET RETIREMENT OBLIGATIONS

The ARO provision represents the present value of the costs to be incurred for the restoration of power generation plants and natural gas liquids extraction and processing plants. The Company estimates that the undiscounted amount of cash flow required to settle the AROs is approximately $453 million, which will be incurred between 2014 and 2111. The pre-tax, risk-free discount rate used to calculate the fair value of the AROs was 1.19% to 4.23% (2012 – 0.34% to 3.27%).

OTHER

The Company has a provision for Australian stamp duty obligations relating to the WA Gas Networks Pty Ltd acquisition.

19. LONG-TERM DEBT AND NON-RECOURSE LONG-TERM DEBT

LONG-TERM DEBT

	Effective Interest Rate	2013	2012
CU Inc. debentures – unsecured			
2004 5.096% due November 2014	5.162%	**100**	100
2002 6.145% due November 2017	6.217%	**150**	150
2004 5.432% due January 2019	5.492%	**180**	180
1999 6.80% due August 2019	6.861%	**300**	300
1990 Second Series 11.77% due November 2020	11.903%	**100**	100
2006 4.801% due November 2021	4.854%	**160**	160
1991 Series 9.92% due April 2022	10.063%	**125**	125
1992 Series 9.40% due May 2023	9.511%	**100**	100
2009 6.215% due March 2024	6.278%	**120**	120
2008 5.563% due May 2028	5.614%	**125**	125
2004 5.896% due November 2034	5.939%	**200**	200
2005 5.183% due November 2035	5.226%	**185**	185
2006 5.032% due November 2036	5.072%	**160**	160
2007 5.556% due October 2037	5.598%	**220**	220
2008 5.580% due May 2038	5.622%	**200**	200
2009 6.500% due March 2039	6.550%	**150**	150
2011 4.543% due October 2041	4.580%	**500**	500
2012 3.805% due September 2042	3.839%	**500**	500
2013 4.722% due September 2043	4.763%	**600**	–
2010 4.947% due November 2050	4.988%	**125**	125
2012 3.857% due November 2052	3.887%	**200**	200
2013 4.558% due November 2053	4.594%	**225**	–
2011 4.593% due October 2061	4.624%	**200**	200
2012 3.825% due September 2062	3.852%	**200**	200
2013 4.855% due September 2063	4.895%	**75**	–
CU Inc. other long-term obligation, due December 2015, unsecured	3.000%	**5**	5
Canadian Utilities Limited debentures – unsecured			
2012 3.122% due November 2022	3.187%	**200**	200
Less: Deferred financing charges		**(29)**	(24)
		5,376	4,481
Canadian Utilities Limited credit facility at 5.72%, due June 2014	5.884%	**35**	37
ATCO Power Australia credit facility, payable in Australian dollars, at Bank Bill rates, due June 2015, secured by a pledge of project assets and contracts $90 million AUD (2012 – $93 million AUD) (1)	Floating (2)	**86**	96
ATCO Gas Australia Limited Partnership credit facility, payable in Australian dollars, at Bank Bill Rates, due June 2015 $250 million AUD (2012 – $250 million AUD) (1)	Floating (2)	**237**	258
ATCO Gas Australia Limited Partnership revolving credit facility, payable in Australian dollars, at Bank Bill Rates, due November 2018 $418 million AUD (2012 – $406 million AUD) (1)	Floating (2)	**396**	419
Less: Deferred financing charges		**(4)**	(3)
		6,126	5,288
Less: Amounts due within one year		**(138)**	(4)
		5,988	5,284

The ATCO Power Australia credit facility is secured by a mortgage on certain assets of the Karratha Power Plant and an assignment of certain contracts and agreements. The Karratha Power Plant is accounted for as a finance lease receivable. The credit facility is guaranteed by Canadian Utilities Limited.

NON-RECOURSE LONG-TERM DEBT

Project Financing	Effective Interest Rate	2013	2012
Joffre:			
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**34**	39
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**7**	15
Term loan, at CDOR, due to 2014 (1)	Floating (2)	**2**	4
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**23**	24
Muskeg River:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**6**	12
Term loan, at CDOR, due to 2014 (1)	Floating (2)	**2**	3
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**20**	24
Cory:			
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**33**	35
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**30**	32
Other:			
Other long-term obligations, at rates of 8.30% to 12.68%, due at various dates to 2015		**10**	–
Less: Deferred financing charges		**(2)**	(2)
		165	186
Less: Amounts due within one year		**(39)**	(30)
		126	156

BA – Bankers' Acceptance

CDOR – Canadian Dealer Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.6% (2012 – 1.9%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 23).*

The non-recourse long-term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2013, was $417 million (2012 – $425 million). The Cory project is accounted for as a finance lease receivable.

GUARANTEES

Canadian Utilities Limited has provided a number of guarantees for ATCO Power's obligations under non-recourse loans for certain of its projects. These guarantees cover the following items:

a) **Project cash flows** – Finance agreements for the Muskeg River and Scotford projects require minimum gross margins to be earned on the merchant capacity of each project. Either ATCO Power or Canadian Utilities Limited is required to fund any shortfall in merchant gross margins each quarter by depositing cash in the project bank accounts. These payments can be distributed back to ATCO Power in the following quarter subject to the projects achieving debt service coverage ratio covenants. At December 31, 2013, no amounts are outstanding under the guarantee. These guarantees expire in 2022 when the project debt is to be fully repaid.

b) Reserve amounts – Represent amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2013, the obligations under these guarantees were:

Project	Major Maintenance	Debt Service
Cory project financing	–	2
Joffre project financing	2	4
Muskeg River project financing	–	8
Scotford project financing	–	7

c) Purchase project assets – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the insolvency of ATCO Power. These guarantees expire in 2022 when the project debt is to be fully repaid. At December 31, 2013, no such events had occurred.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

CONTRACTUAL MATURITIES OF DEBT

The undiscounted contractual maturities of long-term debt and non-recourse long-term debt are as follows:

	Long-Term Debt		Non-Recourse Long-Term Debt		Total	
	Principal	Interest (1)	Principal	Interest (1)	Principal	Interest (1)
2014	138	332	39	9	177	341
2015	325	318	15	12	340	330
2016	–	309	14	7	14	316
2017	150	303	15	6	165	309
2018	396	293	15	5	411	298
2019 and thereafter	5,150	4,760	69	15	5,219	4,775
	6,159	6,315	167	54	6,326	6,369

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2013. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

INTEREST EXPENSE

Interest expense is as follows:

	2013	2012
Long-term debt	**309**	280
Non-recourse long-term debt	**14**	15
Retirement benefits net interest expense	**14**	12
Amortization of deferred financing charges	**3**	3
Accretion of asset retirement obligations	**3**	4
Other	**4**	5
	347	319
Less: Interest capitalized *(Note 13)*	**(65)**	(50)
	282	269

20. DEFERRED REVENUES

	2013	2012
Customer contributions	**1,377**	1,162
Other	**9**	8
	1,386	1,170

CUSTOMER CONTRIBUTIONS

Customer contributions for extensions to plant are included in deferred revenues and are recognized as revenue over the life of the related asset. Changes in deferred customer contribution revenues are summarized below.

	2013	2012
Beginning of year	**1,162**	1,014
Receipt of customer contributions	**266**	184
Amortization	**(50)**	(43)
Other	**(1)**	7
End of year	**1,377**	1,162

21. OTHER LIABILITIES

	2013	2012
Unearned availability incentives	**56**	78
Derivative liabilities *(Note 23)*	**1**	28
Other	**13**	17
	70	123

22. CONTINGENCIES

Measurement inaccuracies occur from time to time on the Utilities' metering facilities. These measurement adjustments are settled between the parties according to requirements of the Electricity and Gas Inspections Act (Canada) and related regulations. Recovery of a measurement adjustment may be disallowed if the AUC finds that controls and timely follow-up are inadequate.

Measurement inaccuracies occur from time to time on ATCO Gas Australia's metering facilities. These measurement adjustments are settled between the parties and the costs are recovered via the tariff based on a predetermined threshold contained in the current Access Arrangement. The Access Arrangement also contains a cost pass-through mechanism for recovery of any increases in gas commodity prices associated with these measurement adjustments. Recovery of a measurement adjustment may be disallowed if the adjustment exceeds a predetermined threshold; currently, levels are tracking below the threshold.

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy. The legal obligations of ATCO Gas and ATCO Electric for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric, with no refund of the transfer proceeds to Direct Energy.

Centrica plc., Direct Energy's parent company, provided a $300 million guarantee, supported by a $235 million letter of credit for Direct Energy's obligations to ATCO Gas, ATCO Electric, and ATCO I-Tek under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to share owners, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board established a Risk Review Committee to review significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Company is exposed to changes in interest rates, foreign currency exchange rates and commodity prices. The Energy segment is affected by the cost of natural gas, the price of natural gas liquids and the price of electricity in the Province of Alberta. The Company may use various instruments, including swaps and forward contracts to manage the risks arising from fluctuations in interest rates, exchange rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2013, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows for a portion of long-term debt and non-recourse long-term debt, foreign currency forward contracts, forward power sales and forward gas purchases.

The derivative assets and liabilities comprise the following:

	Derivative Assets (1)		Derivative Liabilities (2)	
	2013	**2012**	**2013**	**2012**
Current				
Interest rate swap agreements	**–**	–	**10**	2
	–	–	**10**	2
Non-current				
Interest rate swap agreements	**–**	–	**1**	28
Natural gas purchase contracts	**–**	1	**–**	–
	–	1	**1**	28
	–	1	**11**	30

(1) *Current derivative assets are included in prepaid expenses and other current assets. Non-current derivative assets are included in other assets.*

(2) *Current derivative liabilities are included in other current liabilities. Non-current derivative liabilities are included in other liabilities.*

INTEREST RATE RISK

The Company's interest-bearing assets and liabilities include cash and cash equivalents, bank indebtedness, long-term debt and non-recourse long-term debt. The interest rate risk faced by the Company is largely a result of its cash and cash equivalents and long-term debt and non-recourse long-term debt at variable rates.

The Company's cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Company has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

The Company has fixed interest rates, either directly or through interest rate swap agreements, on 99% (2012 – 99%) of total long-term debt and non-recourse long-term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges are recorded in other comprehensive income.

The Company has converted certain variable rate long-term debt and non-recourse long-term debt to fixed rate debt through the following interest rate swap agreements:

Financing	Swap Fixed Interest Rate (1)	Variable Debt Interest Rate	Maturity Date	Notional Principal 2013	2012
Karratha:					
$91 million AUD		Bank Bill Rate			
(2012 – $93 million AUD)	6.160%	in Australia	June 2015	**86**	96
ATCO Gas Australia:					
$200 million AUD		Bank Bill Rate			
(2012 – $200 million AUD)	6.960%	in Australia	June 2014	**190**	207
$160 million AUD		Bank Bill Rate			
(2012 – $160 million AUD)	7.089%	in Australia	June 2014	**152**	165
$200 million AUD		Bank Bill Rate			
(2012 – $200 million AUD)	6.935%	in Australia	June 2014	**190**	207
$40 million AUD		Bank Bill Rate			
(2012 – $40 million AUD)	6.839%	in Australia	June 2014	**38**	41
Scotford:	3.360%	90 day BA	December 2014	**8**	15
	3.758%	3 month CDOR	December 2014	**2**	4
Muskeg River:	2.775%	90 day BA	December 2014	**8**	15
Brighton Beach (2):	4.703%	90 day BA	June 2020	**4**	4
	4.909%	3 month CDOR	June 2020	**3**	4
				681	758

BA – Bankers' Acceptance

CDOR – Canadian Dealer Offered Rate

(1) *The above swap fixed interest rates include any long-term debt margin fees; the margin fees are subject to escalation (Note 19).*

(2) *The Brighton Beach swap was entered into by the Company; however, the non-recourse debt is held within the Company's investment in joint venture.*

FOREIGN CURRENCY EXCHANGE RATE RISK

The Company's earnings from, and carrying values of, its foreign operations are exposed to fluctuations in exchange rates. This foreign exchange impact is partially offset by foreign-denominated financing costs and by the Company's hedging activities. Revenues and expenses in functional currencies other than Canadian dollars are translated at the average monthly rates of exchange during the period. Gains or losses on translation of the assets and liabilities of foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income.

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Company entered into foreign currency forward contracts to manage its exposure to exchange rate risk arising on certain service agreements denominated in U.S. dollars. At December 31, 2013, the contracts consist of purchases of $10 million U.S. in return for $10 million Canadian dollars (2012 – nil).

The possible effect on other comprehensive income, net of income taxes, for the year ended December 31, 2013, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average ten cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

	OCI
Australian dollar	(62)
British pound	1
Total	(61)

(1) *These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.*

ENERGY COMMODITY PRICE RISK

The Company's electricity generation business has exposure to commodity price movements, particularly the market price of electricity and natural gas. At December 31, 2013, approximately 681 MW of power generating plant capacity out of a total capacity owned by ATCO Power of 2,541 MW is sold on the merchant electricity market. This capacity is comprised of approximately 426 MW in Alberta out of a total Alberta-owned capacity of 1,806 MW and all of the U.K. owned capacity of 255 MW. In the U.K., all plant capacity is sold via the merchant balancing mechanism on a daily basis. Following the expiry of the Battle River 3 and 4 PPAs on December 31, 2013, an additional 295 MW of capacity in Alberta is now sold on the merchant electricity market effective January 1, 2014.

Natural gas for contracted capacity is provided either under a long-term supply agreement or is the responsibility of the offtaker. Natural gas capacity not contracted is purchased on a daily basis at spot prices.

The Company is required to pay market prices for substitute energy when it is unable to supply energy under contracted capacity.

The Company has exposure to seasonal summer/winter natural gas price spreads in its non-regulated natural gas storage business.

CREDIT RISK

For cash and cash equivalents and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and cash equivalents credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short-term instruments. Approximately 83% of the cash equivalents at December 31, 2013, was invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to its terms and conditions. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties according to established credit approval policies.

Lease receivable credit risk arises from the possibility that a counterparty to a lease arrangement fails to make lease payments according to its terms and conditions. Lease receivable credit risk is minimized by dealing with large, credit-worthy counterparties according to established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments. The Company does not have a concentration of credit risk with any counterparties, except for lease receivables, which by their nature are with single counterparties. A significant portion of loans and receivables are from the Company's operations in Alberta, except for the lease receivable for the Karratha plant in Australia.

Accounts receivable credit risk is reduced by a large and diversified customer base and credit security such as letters of credit. The Utilities are also able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any losses from retailers beyond the retailer security mandated by provincial regulations. At December 31, 2013, the Company held $67 million and $15 million in letters of credit and parental guarantees, respectively (2012 – $58 million and $3 million). The

Company did not take possession of collateral it holds as security or call on other credit enhancements in the years ended December 31, 2013 and December 31, 2012.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. Changes in the provision for impairment were as follows:

	2013	2012
Beginning of year	**2**	1
Impairment of receivables	**–**	1
End of year	**2**	2

The aging analysis of trade receivables that are past due but not impaired is as follows:

	2013	2012
30 to 90 days	**5**	7
Greater than 90 days	**1**	2
	6	9

No other impairments have been identified within accounts receivable.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long-term financing. The Company has a policy not to invest any of its cash balances in asset backed securities. The Company considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Liquidity is generated by cash flow from operations and supported by appropriate levels of cash and available committed credit facilities.

The Company has contractual obligations in the normal course of business; future minimum undiscounted contractual maturities are as follows:

	2014	2015	2016	2017	2018	2019 and thereafter
Accounts payable and accrued liabilities	777	–	–	–	–	–
Long-term debt *(Note 19)*	138	325	–	150	396	5,150
Non-recourse long-term debt *(Note 19)*	39	15	14	15	15	69
Interest expense *(Note 19)*	341	330	316	309	298	4,775
Operating leases (1)	36	31	27	18	17	22
Purchase obligations:						
Coal purchase contracts (2)	99	101	99	102	105	292
Operating and maintenance agreements (3)	180	155	146	144	147	204
Capital expenditures (4)	150	–	1	–	–	–
Derivatives (5)	10	1	–	–	–	–
Other	14	7	6	1	1	3
	1,784	965	609	739	979	10,515

(1) *Operating leases are comprised primarily of long-term leases for office premises and equipment.*

(2) *ATCO Power has long-term fixed price contracts to purchase coal for its coal-fired generating plants.*

(3) *ATCO Power has long-term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants. ATCO Gas receives all required transmission service from NOVA Gas Transmission Ltd.*

(4) *Various contracts to purchase goods and services with respect to capital expenditures.*

(5) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2013.*

FAIR VALUE OF NON-DERIVATIVE FINANCIAL INSTRUMENTS

The fair value of cash and cash equivalents, accounts receivable, bank indebtedness, and accounts payable and accrued liabilities approximates carrying value due to the short-term nature of the financial instruments.

The fair values of the Company's non-derivative financial instruments measured at other than fair value are as follows:

		2013		2012
Recurring Measurements	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial Assets				
Loans and Receivables:				
Lease receivables (1)	**327**	**499**	347	547
Financial Liabilities				
Amortized Cost:				
Long-term debt (2)	**6,126**	**6,493**	5,288	6,180
Non-recourse long-term debt (2)	**165**	**191**	186	229

(1) *Recorded at amortized cost. Fair values are determined using a risk-adjusted, pre-tax interest rate to discount future cash receipts.*

(2) *Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements. Long-term debt and non-recourse long-term debt are classified in Level 2 of the fair value hierarchy.*

FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS

The fair values of the Company's derivative financial instruments are as follows:

			2013			2012
Recurring Measurements	**Notional Principal or Volume (1)**	**Fair Value Receivable (Payable) (3)**	**Maturity**	**Notional Principal or Volume (1)**	**Fair Value Receivable (Payable) (3)**	**Maturity**
Interest rate swaps	**681**	**(11)**	**2014-2020**	758	(30)	2013-2020
Natural gas purchase contracts (2)	**1,610,548 GJ**	**–**	**2014**	2,296,320 GJ	1	2014
Forward power sales contracts (2)	**182,400 MWh**	**–**	**2014**	48,360 MWh	–	2013
Foreign currency forward contracts	**10**	**–**	**2014**	–	–	–

(1) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(2) *The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts. The notional amount for the forward sale and purchase contracts are the commodity volumes committed in the contracts.*

(3) *Fair values for the interest rate swaps and foreign currency forward contracts have been estimated using period-end market rates. Fair values for the natural gas purchase contracts have been estimated using period-end market prices for natural gas and an estimate of implied volatility based on historic market prices. Fair values for forward power sales contracts have been estimated using forward period-end market prices. These fair values approximate the amount that the Company would either pay or receive to settle the contracts at December 31, 2013.*

The hierarchy of the Company's derivative financial instruments measured at fair value is as follows (see Note 3 for description of hierarchy):

	Level 1	Level 2	Level 3	Total
Current derivative liabilities (1)	–	(10)	–	(10)
Non-current derivative liabilities (2)	–	(1)	–	(1)
	–	(11)	–	(11)

(1) *Current derivative liabilities are included in other current liabilities.*

(2) *Non-current derivative liabilities are included in other liabilities.*

OFFSETTING FINANCIAL ASSETS AND LIABILITIES

The following trade receivables and payables are subject to offsetting, enforceable master netting arrangements and similar agreements:

	2013	2012
Gross amounts of recognized trade receivables	**42**	75
Gross amounts of recognized trade payables	**(22)**	(20)
Net amounts of trade receivables presented in the balance sheet	**20**	55

SENSITIVITY ANALYSIS

The analysis below illustrates the extent to which the Company's results are impacted by derivative financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk).

This analysis reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian and Australian interest rates, the forward price of natural gas and the forward price of power in Alberta. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are highly effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset.

A 25 basis point increase or decrease in Australian or Canadian interest rates would each increase or decrease both earnings and other comprehensive income by less than $1 million. A ten percent increase or decrease in the forward price of natural gas or power in Alberta would each increase or decrease both earnings and other comprehensive income by less than $1 million.

24. EQUITY PREFERRED SHARES

CU INC. EQUITY PREFERRED SHARES

Authorized and issued

Authorized: An unlimited number of Preferred Shares, issuable in series.

Issued:

			2013		2012	
	Stated Value *(dollars)*	Redemption Dates	Shares	Amount	Shares	Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	25.00	See below	**4,600,000**	**115**	4,600,000	115
6.70% Series 2	25.00	See below	**6,400,000**	**160**	6,400,000	160
3.80% Series 4	25.00	See below	**3,000,000**	**75**	3,000,000	75
Issuance costs				**(7)**		(7)
				343		343

Fair values

The CU Inc. preferred shares have a fair value of $323 million at December 31, 2013 (2012 – $360 million) and are classified in Level 1 of the fair value hierarchy. The fair value was determined using quoted market prices of the same issues.

Redemption privileges

The Series 1 Preferred Shares are redeemable at the option of CU Inc. commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

On June 1, 2014, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 2 Preferred Shares in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series 2 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 3 on June 1, 2014, and on June 1 of every fifth year thereafter. Holders of the Series 3 Preferred Shares will be entitled to receive, as and when declared by the Board of CU Inc., floating rate cumulative preferential cash dividends, payable quarterly at a rate equal to the then current 3 month Government of Canada Treasury Bill yield plus 4.81%. On June 1, 2019, and on June 1 of every fifth year thereafter (Series 3 Conversion Date), holders of the Series 3 Preferred Shares may elect to convert any or all of their Series 3 Preferred Shares back into an equal number of Series 2 Preferred Shares. CU Inc. may redeem the Series 3 Preferred Shares in whole or in part at $25.00 on a Series 3 Conversion Date or at $25.50 on any other date.

On June 1, 2016, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 4 Preferred Shares in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series 4 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 5 on June 1, 2016, and on June 1 of every fifth year thereafter. Holders of the Series 5 Preferred Shares will be entitled to receive, as and when declared by the Board of CU Inc., floating rate cumulative preferential cash dividends, payable quarterly at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 1.36%. On June 1, 2021, and on June 1 of every fifth year thereafter (Series 5 Conversion Date), holders of the Series 5 Preferred Shares may elect to convert any or all of their Series 5 Preferred Shares back into an equal number of Series 4 Preferred Shares. CU Inc. may redeem the Series 5 Preferred Shares in whole or in part at $25.00 on a Series 5 Conversion Date or at $25.50 on any other date.

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

				2013		2012
	Stated Value *(dollars)*	**Redemption Dates**	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Second Preferred Shares						
4.00% Series Y	25.00	See below	**13,000,000**	**325**	13,000,000	325
4.90% Series AA	25.00	See below	**6,000,000**	**150**	6,000,000	150
4.90% Series BB	25.00	See below	**6,000,000**	**150**	6,000,000	150
4.50% Series CC	25.00	See below	**7,000,000**	**175**	–	–
4.50% Series DD	25.00	See below	**9,000,000**	**225**	–	–
Perpetual Cumulative Second Preferred Shares						
4.00% Series V	25.00	October 3, 2017	**4,400,000**	**110**	4,400,000	110
Issuance costs				**(20)**		(12)
				1,115		723
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**1,458**		1,066

On March 19, 2013, the Company issued $175 million Cumulative Redeemable Second Preferred Shares Series CC at a price of $25.00 per share under its base shelf prospectus. Holders will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at an annual rate of $1.125 per share to yield 4.50% annually.

On May 15, 2013, the Company issued $225 million Cumulative Redeemable Second Preferred Shares Series DD at a price of $25.00 per share under its base shelf prospectus. Holders will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at an annual rate of $1.125 per share to yield 4.50% annually.

On June 18, 2012, the Company issued $150 million Cumulative Redeemable Second Preferred Shares Series AA at a price of $25.00 per share under its base shelf prospectus. Holders will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at an annual rate of $1.225 per share to yield 4.90% annually. The Company used these proceeds to redeem $150 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X on June 30, 2012.

On July 5, 2012, the Company issued $150 million Cumulative Redeemable Second Preferred Shares Series BB at a price of $25.00 per share under its base shelf prospectus. Holders will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at an annual rate of $1.225 per share to yield 4.90% annually. The Company used these proceeds to redeem $150 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W on July 19, 2012.

Issuance costs of $8 million, net of income taxes, were recorded in equity (as a reduction of equity preferred shares) in the year ended December 31, 2013 (2012 – $6 million).

Effective October 3, 2012, the dividend rate on the Series V Perpetual Cumulative Second Preferred Shares was reset to 4.00% per annum with a redemption date of October 3, 2017.

Fair values

The Canadian Utilities Limited Preferred Shares have a fair value of $1,063 million at December 31, 2013 (2012 – $770 million). All of the shares are classified in Level 1 of the fair value hierarchy with the exception of the Series V Preferred Shares which are classified in Level 2. The fair value was determined using quoted market prices of the same or similar issues.

Redemption privileges

The Series Y Preferred Shares are redeemable at the option of the Company on June 1, 2017, and on June 1 of every fifth year thereafter, the Company may redeem the Series Y Preferred Shares in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series Y Preferred Shares into an equal number of Cumulative Redeemable Second Preferred Shares Series Z on June 1, 2017, and on June 1 of every fifth year thereafter. Holders of the Series Z Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 2.40%. On June 1, 2022, and on June 1 of every fifth year thereafter (Series Z Conversion Date), holders of the Series Z Preferred Shares may elect to convert any or all of their Series Z Preferred Shares back into an equal number of Series Y Preferred Shares. The Company may redeem the Series Z Preferred Shares in whole or in part at $25.00 on a Series Z Conversion Date or at $25.50 on any other date.

The Series AA and Series BB Preferred Shares are redeemable in whole or in part at the option of the Company commencing on September 1, 2017, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until September 1, 2021.

The Series CC Preferred Shares are redeemable in whole or in part at the option of the Company commencing on June 1, 2018, at the stated value plus a 4% premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2022.

The Series DD Preferred Shares are redeemable in whole or in part at the option of the Company commencing on September 1, 2018, at the stated value plus a 4% premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until September 1, 2022.

The Series V Perpetual Cumulative Second Preferred Shares are redeemable on the date specified above at the option of the Company at the stated value plus accrued and unpaid dividends.

25. CLASS A AND CLASS B SHARES AND EARNINGS PER SHARE

In May 2013, the Company's Board approved a two-for-one share split of the outstanding Class A non-voting and Class B common shares. The share split took the form of a share dividend whereby share owners received one additional Class A non-voting share for each Class A non-voting share held as of the record date and one additional Class B common share for each Class B common share held as of the record date. The share dividend was paid on June 14, 2013 to share owners of record at the close of business on June 13, 2013. All share, share-based compensation and per share amounts have been retroactively restated to reflect this share split.

AUTHORIZED AND ISSUED

	Class A Non-Voting		Class B Common		Total	
	Shares	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
January 1, 2012	174,498,966	469	80,734,698	152	255,233,664	621
Shares issued	1,757,106	58	–	–	1,757,106	58
Stock options exercised	122,500	2	–	–	122,500	2
Converted: Class B to Class A	164,800	–	(164,800)	–	–	–
December 31, 2012	**176,543,372**	**529**	**80,569,898**	**152**	**257,113,270**	**681**
Shares issued	**3,726,965**	**134**	**–**	**–**	**3,726,965**	**134**
Stock options exercised	**189,600**	**4**	**–**	**–**	**189,600**	**4**
Converted: Class B to Class A	**5,276,900**	**10**	**(5,276,900)**	**(10)**	**–**	**–**
December 31, 2013	**185,736,837**	**677**	**75,292,998**	**142**	**261,029,835**	**819**

There were 508,651 Class A non-voting shares held in the MTIP trust at December 31, 2013, with a carrying amount of $16 million (2012 – 476,586 shares with a carrying amount of $14 million). The carrying amount of the Class A and B share capital, net of shares held in trust, was $803 million at December 31, 2013 (2012 – $667 million).

There were 1,061,500 options to purchase Class A non-voting shares outstanding at December 31, 2013, under the Company's stock option plan. From January 1, 2014 to February 18, 2014, no stock options were granted, cancelled, or exercised, and 30,900 Class B common shares were converted to Class A non-voting shares. Class A non-voting and Class B common shares have no par value.

EARNINGS PER SHARE

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options and MTIPs on the weighted average Class A non-voting and Class B common shares outstanding.

The earnings and average number of shares used to calculate earnings per share are as follows:

	2013	2012
Average shares:		
Weighted average shares outstanding	**258,432,763**	255,326,382
Effect of dilutive stock options	**364,587**	388,538
Effect of MTIPs	**500,464**	304,266
Weighted average dilutive shares outstanding	**259,297,814**	256,019,186
Earnings for earnings per share calculation:		
Earnings for the period	**606**	572
Dividends on equity preferred shares of the Company	**(45)**	(35)
Dividends on equity preferred shares of subsidiary company	**(19)**	(19)
	542	518
Earnings and diluted earnings per Class A and Class B share:		
Earnings per Class A and Class B share	**$2.10**	$2.03
Diluted earnings per Class A and Class B share	**$2.09**	$2.02

SHARE OWNER RIGHTS

Class A non-voting and Class B common share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B common share owners are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares and if it would result in the offeror owning more than 50% of the outstanding Class B common shares (excluding any Class B common shares acquired upon conversion of Class A shares), the Class A non-voting share owners are entitled, for the duration of the take-over bid, to exchange their Class A non-voting shares for Class B common shares and to tender the newly exchanged for Class B common shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A non-voting share owners are entitled to exchange their shares for Class B common shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

DIVIDEND REINVESTMENT PLAN

On July 12, 2012, the Company announced the implementation of a dividend reinvestment plan (DRIP) which became effective with the quarterly dividend payment in September 2012 to eligible Class A non-voting and Class B common share owners who are enrolled in the program. The DRIP allows eligible Class A non-voting and Class B common share owners of the Company to reinvest all or a specified portion of their dividends in additional Class A non-voting shares.

The Class A non-voting shares are issued from treasury at a two percent discount to the volume weighted average price of the Class A non-voting shares traded on the Toronto Stock Exchange during the last five qualifying trading days preceding the dividend payment date.

During the year ended December 31, 2013, 3,726,965 Class A non-voting shares were issued under the DRIP (2012 – 1,757,106), using re-invested dividends of $134 million (2012 – $58 million). The shares issued by the Company were priced at an average of $35.91 per share (2012 – $33.19 per share).

26. DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	**2013**	**2012**
Equity preferred shares:		
4.00% Perpetual Cumulative Second Preferred Shares, Series V	**1.0000**	1.17500
5.80% Cumulative Redeemable Second Preferred Shares, Series W	**–**	0.91570
6.00% Cumulative Redeemable Second Preferred Shares, Series X	**–**	0.86920
4.00% Cumulative Redeemable Second Preferred Shares, Series Y	**1.00000**	1.00000
4.90% Cumulative Redeemable Second Preferred Shares, Series AA	**1.22500**	0.55796
4.90% Cumulative Redeemable Second Preferred Shares, Series BB	**1.22500**	0.50091
4.50% Cumulative Redeemable Second Preferred Shares, Series CC	**0.79058**	–
4.50% Cumulative Redeemable Second Preferred Shares, Series DD	**0.61725**	–
Class A and Class B shares	**0.97000**	0.88500

The Company's policy is to pay dividends quarterly on its Class A and Class B shares. Increases in the quarterly dividend are addressed by the Board in the first quarter of each year. The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

27. CAPITAL DISCLOSURES

The Company's objectives when managing capital are:

1. To safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders.
2. To maintain strong investment grade credit ratings in order to provide efficient and cost effective access to funds required for operations and growth.
3. To remain within the capital structure approved by the AUC for the Utilities.

In managing its capital, the Company considers both the regulated and non-regulated operations in the consolidated group, as well as changes in economic conditions and risks impacting the Company's operations. In maintaining or adjusting its capital structure, the Company may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long-term debt and non-recourse long-term debt. Financing decisions are based on assessments by management in line with the Company's objectives, with a goal of managing the financial risk to the Company as a whole.

The Utilities are regulated primarily by the AUC and are capitalized consistent with the AUC approved capital structure.

While the Alberta Utilities have an objective of being capitalized consistent with the AUC decision, the Company itself is not restricted in its capital structure. The capital structure for the Company is set relative to risk and to meet the financial and operational objectives of the Company, while considering the decisions of the regulator.

In addition to achieving the above-mentioned objectives, the Company manages capital to comply with the customary covenants on its long-term debt. A common financial covenant for a large portion of the Company's debentures and credit facilities is that total debt divided by total capitalization must be less than 75%. The Company defines total debt as the sum of bank indebtedness, long-term debt and non-recourse debt (including their respective current portion), and defines total capitalization as the sum of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income, equity preferred shares and total debt; however, the definitions of total debt and total capitalization vary slightly in the Company's debt related agreements. Management maintains the debt capitalization ratio well below 75% to sustain access to cost effective financing.

Debt capitalization does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies.

The Company's capitalization is as follows:

	2013	2012
Bank indebtedness	**2**	–
Long-term debt	**6,126**	5,288
Non-recourse long-term debt	**165**	186
Total debt	**6,293**	5,474
Class A and Class B shares	**803**	667
Contributed surplus	**15**	15
Retained earnings	**3,157**	2,642
Accumulated other comprehensive income	**(39)**	(16)
Equity preferred shares	**1,458**	1,066
Total equity	**5,394**	4,374
Total capitalization	**11,687**	9,848
Debt capitalization	**54%**	56%

For the year ended December 31, 2013, the Company complied with externally imposed requirements on its capital, including covenants related to debentures and credit facilities. The Company will continue to assess its capital structure and objectives in light of any future decisions received from the AUC.

28. SHARE-BASED COMPENSATION PLANS

STOCK OPTION PLAN

Of the 12,800,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 5,629,300 Class A non-voting shares were available for issuance at December 31, 2013. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period are determined at the time of grant and cannot exceed ten years. The options have a term of ten years and vest over the first five years.

		2013		2012
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding options, beginning of year	**1,144,250**	**$22.05**	1,169,400	$20.75
Granted	**114,250**	**39.02**	98,750	33.21
Exercised	**(189,600)**	**17.62**	(122,500)	18.63
Forfeited	**(7,400)**	**29.43**	(1,400)	22.17
Outstanding options, end of year	**1,061,500**	**$24.62**	1,144,250	$22.05
Options exercisable, end of year	**786,950**	**$21.74**	872,100	$20.47

Options			Outstanding		Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$15.12 – $18.56	133,000	1.0	$15.20	133,000	$15.20
$21.75 – $23.92	645,000	3.7	22.72	605,000	22.66
$24.74 – $27.05	74,500	7.2	24.87	29,800	24.87
$33.18 – $35.69	95,750	8.2	33.21	19,150	33.21
$37.43 – $40.61	113,250	9.2	39.02	–	–
$15.12 – $40.61	1,061,500	4.6	$24.62	786,950	$21.74

Compensation expense related to stock options was less than $1 million in each of 2013 and 2012.

SHARE APPRECIATION RIGHTS

Directors, officers and key employees of the Company may be granted share appreciation rights (SAR) that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period are determined at the time of grant and cannot exceed ten years. The base value of the SAR is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting Shares, respectively, over the base value of the SAR exercised.

Information about the liabilities arising from SARs is summarized below:

		2013		2012
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	**727,850**	**$24.57**	863,100	$21.43
Granted	**114,250**	**39.02**	98,750	33.21
Exercised	**(56,000)**	**22.77**	(232,600)	16.58
Forfeited	**(7,400)**	**29.43**	(1,400)	22.17
Outstanding SARs, end of year	**778,700**	**$26.78**	727,850	$24.57
SARs exercisable, end of year	**504,150**	**$23.46**	458,900	$23.04

SARs			Outstanding		Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$21.78 – $23.92	495,200	4.1	$23.02	455,200	$22.96
$24.74 – $27.05	74,500	7.2	24.87	29,800	24.87
$33.18 – $35.69	95,750	8.2	33.21	19,150	33.21
$37.43 – $40.61	113,250	9.2	39.02	–	–
$21.78 – $40.61	778,700	5.7	$26.78	504,150	$23.46

Compensation expense related to SARs was $1 million (2012 – $4 million). The total carrying value of liabilities arising from SARs at December 31, 2013, was $6 million (2012 – $6 million). The total intrinsic value of all vested SARs at December 31, 2013, was $7 million (2012 – $8 million).

The Company uses the Black-Scholes option pricing model to estimate the weighted average fair value of the options and SARs granted. The following weighted average assumptions were used:

	2013		2012	
	Options	**SARs**	**Options**	**SARs**
Class A share price	**$39.02**	**$39.02**	$33.21	$33.21
Risk-free interest rate	**1.4%**	**2.0%**	1.7%	1.4%
Share price volatility (1)	**14.1%**	**18.8%**	11.4%	10.4%
Estimated annual Class A share dividend	**2.5%**	**2.7%**	2.7%	2.5%
Expected holding period prior to exercise	**6.8 years**	**6.0 years**	6.8 years	6.1 years

(1) *The share price volatility is based on historical data and reflects the assumption that historical volatility over a period similar to the life of the option is indicative of future trends, which may not necessarily be indicative of exercise patterns that may occur.*

MID-TERM INCENTIVE PLAN

Officers and key employees of the Company may be awarded Class A non-voting shares of Canadian Utilities Limited under a mid-term incentive plan (MTIP). The awards vest after two to three years and are settled with shares purchased on the secondary market. In 2013, the Company, through a trustee, purchased $6 million of shares (2012 – $6 million) to be distributed to employees upon vesting of awards.

	2013		2012	
	MTIPs	**Weighted Average Grant Date Fair Value**	**MTIPs**	**Weighted Average Grant Date Fair Value**
Outstanding MTIPs, beginning of year	**476,586**	**$28.60**	280,144	$25.04
Granted	**173,600**	**38.79**	202,542	33.46
Vested	**(118,000)**	**24.24**	(2,124)	21.17
Forfeited	**(24,250)**	**30.25**	(5,800)	29.53
Change in unallocated shares (1)	**715**	**–**	1,824	–
Outstanding MTIPs, end of year	**508,651**	**$33.03**	476,586	$28.60

(1) *Unallocated shares are Class A non-voting shares held by the trustee which have not been awarded to officers or key employees.*

MTIPs			**Outstanding**
Range of Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Grant Date Fair Value**
$24.85 – $29.30	146,570	0.3	$25.74
$33.38 – $35.66	188,242	1.3	33.47
$37.78 – $40.61	171,300	2.2	38.79
Unallocated shares	2,539	–	–
$24.85 – $40.61	508,651	1.3	$33.03

Compensation expense related to MTIP grants, net of amounts capitalized to property, plant and equipment, amounted to $4 million for 2013 (2012 – $3 million) with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS

Changes in contributed surplus are summarized below:

	2013	2012
Beginning of year	**15**	1
Exercise of stock options	**(1)**	–
Amortization of MTIPs	**5**	4
MTIPs distributed to employees	**(4)**	–
Contributed surplus recognized on initial consolidation of MTIP Trust	**–**	10
End of year	**15**	15

29. RETIREMENT BENEFITS

The Company maintains registered defined benefit and defined contribution pension plans for most of its employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings.

As of 1997, new employees automatically participate in the defined contribution pension plan; employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

The Company also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

The majority of benefit payments are made from trustee-administered funds; however, there are also a number of unfunded plans where the Company meets the benefit payment obligations as they fall due. Plan assets held in trusts are governed by provincial and federal legislation and regulations, as is the relationship between the Company and the trustee. The Pension Committee of the Board of Directors is responsible for governance of the funded plans, including investment decisions and the determination of employer contributions.

Information about the Company's benefit plans, in aggregate, is as follows:

		2013		2012
Benefit plan assets, obligations and funded status	**Pension Benefit Plans**	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Market value of plan assets:				
Beginning of year	**1,953**	**–**	1,790	–
Interest income	**82**	**–**	91	–
Employee contributions	**3**	**–**	3	–
Employer contributions	**66**	**–**	55	–
Benefit payments	**(72)**	**–**	(62)	–
Return on plan assets, excluding amounts included in net interest expense	**129**	**–**	76	–
End of year	**2,161**	**–**	1,953	–
Accrued benefit obligations:				
Beginning of year	**2,441**	**95**	2,099	79
Current service cost	**41**	**2**	37	3
Interest cost	**101**	**4**	106	4
Employee contributions	**3**	**–**	3	–
Benefit payments from plan assets (1)	**(72)**	**–**	(62)	–
Benefit payments by employer	**(5)**	**(4)**	(5)	(3)
Actuarial losses (gains) (2)	**(169)**	**(1)**	263	12
End of year (3)	**2,340**	**96**	2,441	95
Funded status:				
Net retirement benefit obligations (4)	**(179)**	**(96)**	(488)	(95)

(1) *Pension plan benefit payments have historically been indexed annually to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(2) *The actuarial gains were due to an increase in the liability discount rate assumption at December 31, partially offset by an assumption update to reflect longer life expectancy (2012 – a decrease in the liability discount rate assumption at December 31 resulted in the actuarial losses).*

(3) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations decreased to $112 million at December 31, 2013 (2012 – $114 million) due to an increase in the liability discount rate, partially offset by an assumption update to reflect longer life expectancy.*

(4) *The weighted average duration of the defined benefit obligation is 14.9 years.*

	2013		2012	
	Pension Benefit Plans	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Components of benefit plan cost:				
Current service cost	**41**	**2**	37	3
Interest cost	**101**	**4**	106	4
Interest income	**(82)**	**–**	(91)	–
Defined benefit plans cost	**60**	**6**	52	7
Defined contribution plans cost	**29**	**–**	27	–
Total cost	**89**	**6**	79	7
Less: Capitalized	**35**	**2**	29	2
Net cost recognized	**54**	**4**	50	5
Gains (losses) on retirement benefit assets and obligations:				
Return on plan assets, excluding amounts included in net interest expense	**129**	**–**	76	–
Gains (losses) on plan obligations from:				
Changes in demographic assumptions (1)	**(101)**	**(1)**	–	1
Changes in financial assumptions	**43**	**(6)**	64	–
Experience adjustments	**227**	**8**	(327)	(13)
	169	**1**	(263)	(12)
Gains (losses) recognized in other comprehensive income	**298**	**1**	(187)	(12)

(1) *Assumptions regarding future life expectancy are based on a 1994 mortality table, updated for improvements in life expectancy. Assumptions were updated at December 31, 2013 to reflect longer life expectancy consistent with the plans' experience.*

Weighted average assumptions

	2013		2012	
	Pension Benefit Plans	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Assumptions regarding benefit plan cost:				
Discount rate for the year	**4.3%**	**4.3%**	5.2%	5.2%
Average compensation increase for the year	**(1)**	**–**	(1)	–
Assumptions regarding accrued benefit obligations:				
Discount rate at December 31	**4.9%**	**4.9%**	4.3%	4.3%
Long-term inflation rate	**2.0%**	**(2)**	2.0%	(2)

(1) *The assumed average compensation increase is 3.25% for 2013 and thereafter (2012 – 3.75% until the end of 2012 and 3.25% thereafter).*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated OPEB obligation are as follows: for drug costs, 5.97% for 2013 grading down over eleven years to 4.5% (2012 – 6.1% for 2012 grading down over twelve years to 4.5%), for other medical costs, 4.5% for 2013 and thereafter (2012 – 4.5% for 2012 and thereafter), and for dental costs, 4.0% for 2013 and thereafter (2012 – 4.0% for 2012 and thereafter).*

PENSION BENEFIT PLAN ASSETS

	2013				2012			
	Quoted	Un-quoted	Total	%	Quoted	Un-quoted	Total	%
Plan asset mix:								
Equity securities [1]								
Public	**769**	**–**	**769**		926	–	926	
Private	**–**	**29**	**29**		–	33	33	
	769	**29**	**798**	**37**	926	33	959	49
Fixed income securities								
Government bonds	**623**	**–**	**623**		370	–	370	
Corporate bonds and debentures	**525**	**–**	**525**		454	–	454	
Mortgages	**–**	**24**	**24**		–	15	15	
	1,148	**24**	**1,172**	**54**	824	15	839	43
Real estate								
Land and building [2]	**–**	**69**	**69**		–	68	68	
Real estate funds	**–**	**64**	**64**		–	49	49	
	–	**133**	**133**	**6**	–	117	117	6
Cash and other assets								
Cash	**12**	**–**	**12**		5	–	5	
Short-term notes and money market funds	**38**	**–**	**38**		26	–	26	
Accrued interest and dividends receivable	**8**	**–**	**8**		7	–	7	
	58	**–**	**58**	**3**	38	–	38	2
	1,975	**186**	**2,161**	**100**	1,788	165	1,953	100

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2013, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $399 million and $125 million, respectively (2012 – $201 million and $187 million, respectively).*

(2) *The land and building are occupied by the Company.*

At December 31, 2013, plan assets include long-term debt of CU Inc. having a market value of $24 million (2012 – $27 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $34 million (2012 – $36 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $41 million (2012 – $35 million).

FUNDING

Employees contribute a percentage of their salary to registered pension plans. The Company contributes its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided at retirement for the members of the defined benefit pension plans.

Funding contributions for 2012 and 2013 were set according to actuarial valuations for funding purposes as of December 31, 2009 and December 31, 2012, respectively. Based on these actuarial valuations, employer contributions relating to the defined benefit component of the plans for 2013 were $66 million (2012 – $55 million); this amount is also the estimated contribution for 2014. The next actuarial valuation for funding purposes must be completed as of December 31, 2015.

Employer contributions relating to the defined contribution component of the plans for 2013 were $30 million (2012 – $27 million).

RISKS AND SENSITIVITIES

Through its defined benefit pension plans and OPEB plans, the Company is exposed to a number of risks, the most significant of which are detailed below.

Investment risk

The Company makes investment decisions for its funded plans using an asset-liability matching framework. Within this framework, the Company's objective over time is to increase the proportion of plan assets in fixed income securities with maturities that match the expected benefit payments as they fall due. However, due to the long-term nature of the plan liabilities, the strength of the Company and the belief that equities offer the best returns over the long-term with an acceptable level of risk, the Company continues to invest in equity securities. This investment is an important element of the Company's long-term strategy to manage the plans efficiently. The equities securities are in a diversified portfolio of high-quality businesses. The Company has not changed the processes used to manage its risks from previous periods.

Discount rate

A decrease in the discount rate will increase plan liabilities, but will also increase the value of the plans' bond holdings.

Compensation risk

The present value of the defined benefit plan liabilities is calculated by reference to the estimated future compensation of plan participants. Should future compensation be higher than estimated, plan liabilities will increase.

Inflation risk

All of the plans' benefit obligations are linked to inflation, and higher inflation will lead to higher liabilities. For the defined benefit pension plans, inflation risk is mitigated because the indexing of benefit payments is capped at an increase of 3.0% per annum.

The majority of plan assets are also affected by inflation. As inflation rises, long-term interest rates will likely rise, pushing up bond yields and lowering the value of existing fixed rate bonds. The relationship between equities and inflation is not as clear, but generally speaking, high inflation has a negative impact on equity valuations. Overall, rising inflation will likely reduce a defined benefit pension plan surplus or increase a deficit.

Life expectancy

The present value of the plan liabilities are calculated by reference to the estimated life expectancy of plan participants. Should life expectancy increase compared to the estimate, plan liabilities will increase.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2013 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and methodology used in preparing the sensitivity analysis has not changed compared to previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized within the consolidated balance sheet and consolidated statement of earnings, respectively.

	2013 Pension Benefit Plans		**2013 OPEB Plans**	
	Accrued Benefit Obligation	**Net Benefit Plan Cost**	**Accrued Benefit Obligation**	**Net Benefit Plan Cost**
Discount rate				
1% increase	(340)	(12)	(15)	–
1% decrease	429	11	19	–
Future compensation rate				
1% increase	45	2	–	–
1% decrease	(43)	(2)	–	–
Long-term inflation rate				
1% increase [(1)] [(2)]	344	12	13	–
1% decrease [(2)]	(285)	(10)	(10)	–
Life expectancy				
10% increase	71	2	3	–
10% decrease	(63)	(2)	(3)	–

(1) *The long-term inflation rate for pension plans reflects the fact that pension plan benefit payments have historically been indexed annually to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(2) *The long-term inflation rate for OPEB plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

30. CHANGES IN NON-CASH WORKING CAPITAL

	2013	**2012**
Operating activities, changes related to:		
Accounts receivable	**50**	(124)
Inventories	**(1)**	1
Prepaid expenses and other current assets	**16**	–
Accounts payable and accrued liabilities	**50**	23
Provisions and other current liabilities	**(1)**	3
	114	(97)
Investing activities, changes related to:		
Accounts receivable	**1**	1
Inventories	**(11)**	(1)
Prepaid expenses	**(1)**	–
Accounts payable and accrued liabilities	**(68)**	231
	(79)	231

31. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its subsidiary companies, the Company provided computer operations and systems development services totalling $11 million (2012 – $11 million), recovered administrative expenses totaling $1 million (2012 – $1 million), incurred administrative expenses, rent expense and corporate signature rights totaling $13 million (2012 – $11 million) and trailer supply and noise management services of $15 million (2012 – $19 million), which were capitalized to property, plant and equipment.

In transactions with an affiliates' joint ventures, the Company incurred lodging costs of nil (2012 – $6 million), which were capitalized to property, plant and equipment.

In transactions with the Company's group pension plans, the Company paid occupancy costs of $7 million (2012 – $7 million) relating to property owned by the pension plans.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Effective November 2013, ATCO Gas and ATCO Electric transferred land and buildings to ATCO Real Estate Holdings Ltd., all of which are wholly owned subsidiaries of the Company. This transfer was a related party transaction by entities under common control and was accounted for at the carrying amount. Land and buildings were transferred for cash consideration of $2 million. The land and buildings were previously recognized in the Utilities segment; from November 2013, onward, they are recognized in the Corporate and Other segment.

Effective July 1, 2012, ATCO Pipelines transferred ownership of its non-regulated Muskeg River Pipeline and certain land and water system assets to ATCO Energy Solutions, both of which are wholly owned subsidiaries of the Company. This transfer was a related party transaction by entities under common control and was accounted for at the carrying amount of $45 million. The Muskeg River Pipeline and certain land and water system assets were previously recognized in the Utilities segment; from July 1, 2012, onward, they are recognized in the Energy segment.

At December 31, 2013, accounts receivable due from related parties amounted to $3 million (2012 – $7 million) and accounts payable due to related parties amounted to $10 million (2012 – $12 million). Receivables and payables with related parties are generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

The Company issued 2,789,988 Class A non-voting shares to ATCO Ltd. under the DRIP in 2013 (2012 – 1,349,008 shares), using re-invested dividends of $100 million (2012 – $45 million). The shares were priced at an average of $35.91 per share (2012 – $33.21 per share).

KEY MANAGEMENT COMPENSATION

	2013	2012
Salaries and short-term employee benefits	**11**	10
Retirement benefits	**1**	1
Share-based compensation	**7**	7
	19	18

Key management personnel comprise members of executive management and the Board, a total of 18 individuals (2012 – 19 individuals).

32. SUBSEQUENT EVENTS

On January 9, 2014, the Company declared quarterly eligible dividends of $0.25000 on the Series Y Preferred Shares, $0.30625 on the Series AA Preferred Shares, $0.30625 on the Series BB Preferred Shares, $0.28125 on the Series CC Preferred Shares and $0.28125 on the Series DD Preferred Shares.

On January 9, 2014, the Company declared a quarterly dividend of $0.2675 per Class A non-voting share and Class B common share.