News Release

FOR IMMEDIATE RELEASE

ALTAGAS CANADA INC. DELIVERS SOLID FULL-YEAR FINANCIAL RESULTS WITH STRONG EARNINGS GROWTH FROM BOTH UTILITIES AND RENEWABLES

Calgary, Alberta (March 5, 2020) – AltaGas Canada Inc. ("ACI") (TSX: ACI) today announced its fourth quarter and full year 2019 financial results.

Highlights:

- Achieved normalized net income[1] of $45.3 million ($1.51 per share) for 2019, an increase of approximately 12 percent over 2018 adjusted normalized net income of $40.5 million ($1.35 per share)[2];
- Delivered five percent growth in combined utilities rate base, which increased to $941 million at year end 2019 compared to $895 million at the end of 2018[3];
- Received approval from the British Columbia Utilities Commission ("BCUC") for a new rate required in the proposed auction process to allocate reactivated capacity on Pacific Northern Gas' western transmission pipeline (the "PNG Reactivation Application");
- ACI continues to execute on its robust growth capital program and expects to spend $450 - $525 million between 2020 - 2024;
- ACI expects approximately six percent compound annual normalized net income growth over the 2020 - 2024 period; and
- Shareholders of ACI and the Alberta Utilities Commission ("AUC") have approved the indirect acquisition of ACI by the Public Sector Pension Investment Board ("PSP Investments") and the Alberta Teachers' Retirement Fund Board ("ATRF"). The transaction remains on track for closing in the first half of 2020.

For the full year 2019, net income after taxes was $42.1 million ($1.40 per share) compared to $45.3 million ($1.51 per share) in 2018. Normalized net income for 2019 was $45.3 million ($1.51 per share) compared to adjusted normalized net income of $40.5 million ($1.35 per share) in 2018.

"We are very pleased with our 2019 results which clearly demonstrate the strength of our business," said Jared Green, President and Chief Executive Officer of ACI. "We have a great trajectory in front of us and numerous growth opportunities to capitalize on. 2020 will be instrumental to our growth plans as we move ahead with the reactivation of our PNG natural gas transmission line."

1. *Non-GAAP measure; see discussion in the advisories of this news release and reconciliation to U.S. GAAP financial measures shown in ACI's Management's Discussion and Analysis (MD&A) as at and for the period ended December 31, 2019, which is available on www.sedar.com*
2. *Non-GAAP measure; see discussion in the advisories as well as the reconciliation to U.S. GAAP financial measures in this press release.*
3. *Includes work-in-progress on multi-year projects which accrue allowance for funds used during construction.*

Normalized net income for 2019 increased over 2018 primarily due to strong rate base growth at all utilities, higher approved rates, colder weather in Nova Scotia and stronger results from the Northwest Hydro facilities.

In the fourth quarter of 2019, net income after taxes was $16.1 million ($0.54 per share) compared to $20.8 million ($0.69 per share) for the same period in 2018. Normalized net income for the fourth quarter 2019 was $18.6 million ($0.62 per share) compared to $20.0 million ($0.67 per share) in the fourth quarter of 2018. While results benefited from rate base growth, higher approved rates, colder weather in Alberta and higher overall renewable generation, these were offset primarily due to increases in operating and administrative expenses, depreciation and income tax expense.

2020 – 2024 Capital Program and Outlook

Over the 2020 to 2024 time period, ACI expects to achieve approximately six percent compound annual normalized net income growth. Over this period, ACI expects to spend $450 to $525 million at its utilities. The expected capital program includes the PNG Reactivation Project as well as investments in system betterment projects to maintain the safety and reliability of ACI's utility infrastructure, new business opportunities and technology improvements. In 2020, ACI expects capital spend to be in the range of $75 to $85 million.

PNG Reactivation Application

On June 28, 2019, PNG submitted an application to the BCUC for approval of a large volume industrial transportation rate required in its proposed process for allocation of reactivated capacity on its existing pipeline system. The proposed reactivation involves natural gas deliveries from Station 4a on the Enbridge Westcoast Energy Inc. southern mainline near Summit Lake, British Columbia to three termination points: Terrace, Kitimat, and Prince Rupert, British Columbia.

On February 28, 2020, PNG received BCUC approval for the PNG Reactivation Application and now plans to conduct a binding open season auction where shippers will have the opportunity to bid on capacity of up to approximately 88 million standard cubic feet per day based on either firm transportation service agreements ("TSA") or reserve capacity through transportation reservation agreements. PNG has garnered strong interest from a number of potential shippers. Provided there are sufficient shipper commitments backed by TSAs, PNG would commence system reactivation and recommissioning work to prepare for returning the system back to full utilization, subject to BCUC approvals. Depending on shipper demands and the requested delivery points, PNG estimates the capital cost for the reactivation, recommissioning and system reinforcement could be up to $120 million.

Pending Acquisition of ACI

On October 21, 2019, ACI announced it had entered into a definitive arrangement agreement pursuant to which the PSP Investments and ATRF will indirectly acquire through PSPIB Cycle Investments Inc., all of the issued and outstanding Common Shares of ACI for $33.50 in cash per Common Share pursuant to a plan of arrangement under the *Canada Business Corporations Act* (the "Arrangement"). The Board of Directors, after receiving the unanimous recommendation of an independent committee of the Board of Directors formed to review and consider various strategic and financial options available to ACI and in consultation with its financial and legal advisors, unanimously determined that the Arrangement is in the best interests of ACI and fair to the Shareholders and therefore unanimously recommended that holders of Common Shares vote in favour of the Arrangement.

On December 19, 2019, the Shareholders voted to approve the Arrangement and on December 20, 2019, ACI received an Order from the Court of Queen's Bench of Alberta approving the transaction.

ACI has received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not intend to challenge the proposed acquisition, as well as approval of the transaction from the AUC.

Closing of the Arrangement remains subject to approval of the transaction from the BCUC and the satisfaction or waiver of other customary closing conditions. The Arrangement is expected to close in the first half of 2020.

ACI Dividend Declaration

On March 4, 2020 the Board of Directors of ACI declared a dividend of $0.26 per Common Share, payable on March 31, 2020 to Shareholders of record at the close of business on March 13, 2020. The ex-dividend date is March 12, 2020. This dividend is an eligible dividend for Canadian income tax purposes.

Selected Financial Information

The following tables summarize key financial results:

($ millions)	Three Months Ended December 31 2019	Three Months Ended December 31 2018	Year Ended December 31 2019	Year Ended December 31 2018
Normalized EBITDA(1)(2)	**40.1**	34.2	**113.5**	105.2
Operating income	**26.4**	27.2	**73.4**	76.0
Net income after taxes	**16.1**	20.8	**42.1**	45.3
Normalized net income(1)	**18.6**	20.0	**45.3**	41.8
Total assets	**1,582.3**	1,515.5	**1,582.3**	1,515.5
Total long-term liabilities	**852.4**	815.4	**852.4**	815.4
Net additions to property, plant and equipment	**27.4**	24.7	**69.7**	68.2
Dividends declared(3)	**7.8**	5.2	**29.9**	5.2
Cash from operations	**17.2**	26.4	**76.6**	89.9
Normalized funds from operations(1)	**34.7**	28.6	**79.9**	88.1

($ per Common Share, except Common Shares	Three Months Ended December 31 2019	Three Months Ended December 31 2018	Year Ended December 31 2019	Year Ended December 31 2018
Net income after taxes – basic	**0.54**	0.69	**1.40**	1.51
Net income after taxes – diluted	**0.53**	0.69	**1.40**	1.51
Normalized net income - basic(1)	**0.62**	0.67	**1.51**	1.39
Dividends declared(3)	**0.2600**	0.1744	**0.9950**	0.1744
Cash from operations	**0.57**	0.88	**2.55**	3.00
Normalized funds from operations(1)	**1.16**	0.95	**2.66**	2.94
Weighted average number of Common Shares outstanding - basic (millions)(4)	**30.0**	30.0	**30.0**	30.0

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of the MD&A as at and for the year ended December 31, 2019.

(2) Effective January 1, 2019, ACI revised the calculation of normalized EBITDA to incorporate ACI's proportionate share of normalized EBITDA from its equity investments instead of just the equity pickup. The comparative periods have been revised to conform to the current period presentation. Please refer to "*Non-GAAP Financial Measures*" section of the MD&A as at and for the year ended December 31, 2019.

(3) Dividend declared per Common Share after the completion of the initial public offering ("IPO").

(4) For comparative purposes, the Common Shares issued under the IPO including the Over-Allotment Option, have been assumed to be outstanding as of January 1, 2018.

Adjusted Normalized Net Income and Net Income After Taxes

For year ended December 31, 2018 *($ millions)*	As reported	Adjustments	Adjusted
Operating income	**$ 76.0**	**$ —**	**$ 76.0**
Interest expense (1)	(28.5)	(1.8)	(30.3)
Income tax expense (2)	(2.2)	0.5	(1.7)
Net income after taxes	**$ 45.3**	**$ (1.3)**	**$ 44.0**
Unrealized loss on foreign exchange contracts	(1.7)	—	(1.7)
Part VI.1 revenue from AltaGas Ltd.	(1.8)	—	(1.8)
Normalized net income (3)	**$ 41.8**	**$ (1.3)**	**$ 40.5**

(1) Adjustment to reflect financing charges and expenses associated with incremental debt additions at ACI as if they had occurred at the beginning of the period. Please refer to the *Capital Resources* section of the MD&A as at and for the period ended December 31, 2019 for the capital structure subsequent to the acquisition of ACI's assets from AltaGas Ltd. and the IPO.

(2) Tax shield associated with incremental cost adjustments assuming a 27 percent statutory tax rate.

(3) Non-GAAP financial Measures. See *Non-GAAP Financial Measures* section of the MD&A as at and for the year ended December 31, 2019.

About ACI

ACI is a Canadian company with natural gas distribution utilities and renewable power generation assets. ACI serves approximately 130,000 customers, delivering low carbon energy, safely and reliably. For more information visit: www.altagascanada.ca.

For Further Information Contact:

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This news release contains forward-looking information (forward-looking statements). Words such as "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "expect", "project", "target", "potential", "objective", "continue", "outlook", "opportunity" and similar expressions suggesting future events or future performance, as they relate to ACI or any affiliate of ACI, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to: expectations regarding the Arrangement (as defined herein), including the expected closing date; expectation that ACI's 5-year capital spend program will be $450 - $525 million; expectations regarding arrangements in relation to the PNG Reactivation Application (as defined herein), including the reactivation process, process for determining customer demand and allocating capacity, the estimated capital cost for the reactivation, commissioning and system reinforcement and the plan to conduct a binding open season auction; expected compound annual normalized net income growth of approximately 6 percent between 2020 – 2024; expected 2020 capital spend in the range of $75 to $85 million; and timing of the March dividend payment.

ACI's forward-looking statements are subject to certain risks and uncertainties which could cause results or events to differ from current expectations, including, without limitation: that the Arrangement may not be completed on a timely basis, if at all; the conditions to the Arrangement, including receipt of approval from BCUC, may not be satisfied; legislative and regulatory environment; demand for natural gas; access to and use of capital markets; market value of ACI's securities; ACI's ability to pay dividends; ACI's ability refinance its debt; prevailing economic conditions; the potential for service interruptions and physical damage to infrastructure; natural gas supply; ability of the company to maintain, replace and expand its regulated assets; and impact of labour relations and reliance on key personnel. Applicable risk factors are discussed more fully under the heading "Risk Factors" in ACI's Annual Information Form for the year ended December 31, 2019, will be available on www.sedar.com.

Many factors could cause ACI's actual results, performance or achievements to vary from those described in this news release, including, without limitation, those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, expected, projected or targeted and such forward-looking statements included in this news release, should not be unduly relied upon. The impact of any one assumption, risk, uncertainty or other factor on a particular *forward-looking statement cannot be determined with certainty because they are interdependent and ACI's future decisions and actions will depend on management's assessment of all information at the relevant time. Such statements speak only as of the date of this news release. ACI does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this news release are expressly qualified by these cautionary statements.*

Financial outlook information contained in this news release about prospective financial performance, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this news release should not be used for purposes other than for which it is disclosed herein.

This news release contains references to certain financial measures used by ACI that do not have a standardized meaning prescribed by U.S. GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with U.S. GAAP. The non-GAAP measures and their reconciliation to US GAAP financial measures are shown in ACI's MD&A as at and for the period ended December 31, 2019. These non-GAAP measures provide additional information that Management believes is meaningful in describing ACI's operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

Normalized net income represents net income after taxes adjusted for after tax impact of unrealized gain (loss) on foreign exchange contracts and other typically non-recurring items. This measure is presented in order to enhance the comparability of results, as it reflects the underlying performance of ACI. Normalized net income as presented should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized EBITDA is a measure of ACI's operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using operating income adjusted for depreciation and amortization expense, accretion expenses, foreign exchange gain (loss), unrealized gain (loss) on foreign exchange contracts, and other typically non-recurring items. Normalized EBITDA is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets and the capital structure.

Normalized funds from operations is used to assist Management and investors in analyzing the liquidity of ACI without regard to changes in operating assets and liabilities in the period as well as other non-operating related expenses. Management uses this measure to assess the ability to generate funds for use in investing and financing activities.

MANAGEMENT'S DISCUSSION AND ANALYSIS

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars unless otherwise indicated.)

This Management's Discussion and Analysis ("MD&A") dated March 4, 2020 is provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Canada Inc. ("ACI" or the "Company") as at and for the year ended December 31, 2019. This MD&A should be read in conjunction with the accompanying audited consolidated financial statements as at and for the year ended December 31, 2019 (the "Consolidated Financial Statements"). Please refer to note 2 of the Consolidated Financial Statements for important information regarding the basis of preparation of the Consolidated Financial Statements.

The Company presents the Consolidated Financial Statements in Canadian dollars. In this MD&A, references to "$" are to Canadian dollars unless otherwise indicated. The Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") as codified by the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"). Throughout this MD&A, reference to GAAP refers to U.S. GAAP. Any reference to per Common Share measures are presented on a basic basis, unless otherwise indicated.

This MD&A refers to certain terms commonly used in the rate-regulated utility industry, such as "rate-regulated", "rate base" and "return on equity". The terms "rate base" and "return on equity" are key performance indicators but are not considered non-GAAP measures. Rate base is an amount that a utility is required to calculate for regulatory purposes, and generally refers to net book value of the utility's assets for regulatory purposes. Return on equity or "ROE" is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base. The Company refers to the rate base and return on equity of its utility businesses because it believes that such terms assist in understanding the Company's business and are commonly used by investors and research analysts to help evaluate the performance of rate-regulated utilities. For a discussion of these terms, please see the "*Business of Company - Utilities Business*" section in the annual information form of ACI dated March 4, 2020 (the "Annual Information Form").

Abbreviations, acronyms, and capitalized terms used in this MD&A that are not otherwise defined herein are used consistently with the definitions in the Annual Information Form.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words ''expect'', ''anticipate'', ''continue'', ''estimate'', ''objective'', ''ongoing'', ''may'', ''will'', ''should'', ''believe'', ''plan'', "would", "could", "focus", "forecast", "opportunity" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: ACI's vision and objectives; the implementation and success of ACI's strategy as a whole and each of its business segments; expectations regarding the Arrangement (as defined herein), including the expected closing date and the impact on the financial condition, financial performance and future cash flows of the Company; the expected in-service date for the Atlantic Bridge Expansion Project; expectations regarding HGL's (as defined herein) application with the NSUARB (as defined herein) requesting to extend its CRP (as defined herein) and reduce deferrals; expectations regarding arrangements in relation to the PNG Reactivation Application (as defined herein), including the reactivation process, process for determining customer demand and allocating capacity, the plan to conduct a binding open season auction, and the estimated capital cost for the reactivation, commissioning and system reinforcement; expectations regarding PNG's 2020 and 2021 revenue requirement applications and expected timing of BCUC (as defined herein) decision; AUC (as defined herein) decisions with regard to the Etzikom Lateral Project (as defined herein); expected success of financing plans and strategies, including maintenance of ACI's credit rating; the expected safety and reliability of ACI's operations; the expected good working relationships with stakeholders and governments; sources and terms of natural gas supply; the expected impacts on ACI's business of applicable environmental regulations and requirements; expectations regarding compound annual normalized net income growth, planned expenditures and related investments and capital program from 2020 to 2024 and the expected capital spend in 2020; expected fluctuations in the Company's working capital and the expected funding of the Company's capital program; the Company's objective for managing capital and its effects on rate base and return to investors; and expected impact of adopting ASUs in the future on the Company's consolidated financial statements.

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Company including, without limitation: expected commodity supply, demand and pricing; that the Company will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; regulatory approvals and policies; funding operating and capital costs; project completion dates; capacity expectations; that there will be no material defaults by the counterparties to agreements with the Company and such agreements will not be terminated prior to their scheduled expiry; and the Company will continue to have access to wind and water resources in amounts consistent with the amounts expected by the Company. The Company believes the material factors, expectations and assumption reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information and statements, including, without limitation: that the Arrangement (as defined herein) may not be completed on a timely basis, if at all; the conditions to the Arrangement, including receipt of approval from BCUC, may not be satisfied; changes in the demand for or supply of the Company's services; unanticipated operating results; changes in regulatory matters; limited, unfavourable or a lack of access to capital markets; increased costs; the impact of competitors; attracting and retaining skilled personnel and certain other risks (including, without limitation, those risks identified elsewhere in this MD&A); and the other factors discussed under the heading *"Risk Factors"* in the Annual Information Form and set out in the Company's other continuous disclosure documents.

The estimates of certain of the Company's financial results constitutes a financial outlook in respect of financial performance based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. See "*Outlook and Capital Program*".

These estimates are based on the same assumptions, risk factors, limitations and qualifications as set forth. The estimates reflect management's reasonable expectations, based on historical experience, regarding the extent to which each of the foregoing expectations and assumptions is likely to occur.

The financial outlook or potential financial outlook set forth in this MD&A were approved by management as of the date of this MD&A and are provided for the purpose of providing investors with an estimation of the 2020 to 2024 outlook. Readers are cautioned that any such financial outlook contained herein should not be used for purposes other than those for which it is disclosed herein.

The prospective financial information set forth in this MD&A has been prepared by, and is the responsibility of, management. The Company and management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represents, to the best of management's knowledge and opinion, the Company's expected course of action in developing and executing its business strategy and growth opportunities relating to its business operations. However, actual results will likely vary from the prospective financial information set forth in this MD&A, and such variation could be material. See above for a discussion of the risks that could cause actual results to vary. The prospective financial information set forth in this MD&A should not be relied on as necessarily indicative of future results.

The Company believes the forward-looking statements in this MD&A are reasonable. However, such statements are not a guarantee that any of the actions, events or results of the forward-looking statements will occur, or if any of them do occur, their timing or what impact they will have on the Company's results of operations or financial condition. Because of these uncertainties, investors should not put undue reliance on any forward-looking statements.

The forward-looking statements included in this MD&A are expressly qualified by this cautionary statement and are made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by Canadian securities laws.

Additional information relating to the Company, including the Annual Information Form, is available on SEDAR at *www.sedar.com.*

THE COMPANY

ACI was incorporated under the *Canada Business Corporations Act* (the "CBCA") on October 27, 2011 as AltaGas Utility Holdings (Pacific) Inc., a wholly owned subsidiary of AltaGas Ltd. ("AltaGas"). On September 5, 2018, ACI amended its articles to, among other things, facilitate it becoming a public company, change its name to AltaGas Canada Inc., amend its authorized capital and consolidate its outstanding Common Shares on the basis of one post-consolidation Common Share for every 28 pre-consolidation Common Shares. Prior to the Acquisition, as further described under the "*Significant Events - 2018"* section of this MD&A, the Company owned rate-regulated natural gas distribution and transmission utility assets in British Columbia through its subsidiaries, Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)"). Subsequent to the Acquisition, the Company owns rate-regulated natural gas distribution and transmission utility businesses in Alberta, British Columbia, Nova Scotia and the Northwest Territories, the Bear Mountain Wind Park (as defined herein) and an approximately 10 percent indirect interest in the Northwest Hydro Facilities (as defined herein). The Company became a reporting issuer on October 18, 2018 and its Common Shares commenced trading on the Toronto Stock Exchange on October 25, 2018 under the symbol "ACI".

VISION, OBJECTIVE AND STRATEGY

ACI's vision is to be the clean energy supplier of choice in each of the jurisdictions in which it operates through being a leader in safety, reliability, cost effectiveness and customer service. Through disciplined investments in its utilities and in contracted renewable power opportunities, the Company is committed to achieving long-term sustainable growth. Safety, customer service and earnings per Common Share are the primary measures of performance for the Company.

The Company's objective is to: (a) provide safe, reliable, clean and cost-effective energy to its customers; (b) create stable, predictable returns with strong organic growth for investors through the ownership of rate-regulated utilities and renewable power assets contracted through long-term electricity purchase agreements ("EPAs") with creditworthy counterparties; and (c) pay out a portion of its net income to the Shareholders on a quarterly basis.

The Company's strategy is focused on delivering safe, reliable, clean and cost-effective energy solutions to customers while achieving long-term profitable growth. Through the Company's diversified rate-regulated natural gas distribution and transmission utilities assets and long-term contracted renewable power generation assets, the Company expects to deliver low-risk, stable, predictable earnings and cash flows. The Company works to maintain strong relationships with regulators and be seen as a credible proponent for regulatory initiatives.

SIGNIFICANT EVENTS

2019

Pending Acquisition of ACI

On October 21, 2019, ACI announced it had entered into a definitive arrangement agreement (the "Arrangement Agreement") pursuant to which the Public Sector Pension Investment Board and the Alberta Teachers' Retirement Fund Board (together, the "Consortium") will indirectly acquire through PSPIB Cycle Investments Inc. (the "Purchaser"), all of the issued and outstanding Common Shares of ACI for $33.50 in cash per Common Share pursuant to a plan of arrangement under the CBCA (the "Arrangement"). The Board of Directors, after receiving the unanimous recommendation of an independent committee of the Board of Directors formed to review and consider various strategic and financial options available to ACI and in consultation with its financial and legal advisors, unanimously determined that the Arrangement is in the best interests of ACI and fair to the Shareholders and therefore unanimously recommended that holders of Common Shares vote in favour of the Arrangement.

On December 19, 2019, the Shareholders voted to approve the Arrangement and on December 20, 2019, ACI received the Final Order from the Court of Queen's Bench of Alberta approving the transaction.

ACI has received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not intend to challenge the proposed acquisition, as well as approval of the transaction from the Alberta Utilities Commission ("AUC").

Closing of the Arrangement remains subject to approval of the transaction from the British Columbia Utilities Commission ("BCUC") and the satisfaction or waiver of other customary closing conditions. The Arrangement is expected to close in the first half of 2020.

The Company is expected to incur certain customary closing costs but the closing of the Arrangement is not expected to have a material impact on the financial condition, financial performance and future cash flows of the Company.

2018

Acquisition of Assets from AltaGas (the "Acquisition")

On October 18, 2018, pursuant to the Purchase and Sale Agreement, the Company acquired the following assets from AltaGas for approximately $889.1 million (the "Acquired Assets") through the acquisition of (a) all of the issued and outstanding common shares of AltaGas Utility Group Inc. ("AUGI"); (b) all of the issued and outstanding common shares of Bear Mountain Wind Power Corporation ("BMWPC"); (c) AltaGas' 99.99 percent partnership interest in Bear Mountain Wind Limited Partnership ("BMWLP") as a limited partner; (d) AltaGas' 99.99 percent partnership interest in AltaGas Canadian Energy Holdings Limited Partnership as a limited partner; (e) all of the issued and outstanding common shares of AltaGas Canadian Energy Holdings Ltd.; and (f) 10 common shares in the capital of Northwest Hydro GP Inc. ("Coast GP"), the general partner of Northwest Hydro Limited Partnership ("Coast LP"):

- Rate-regulated natural gas distribution utility assets in Alberta and Nova Scotia owned by AUGI via its operating subsidiaries, AltaGas Utilities Inc. ("AUI") and Heritage Gas Limited ("HGL");
- Minority interests in entities (Inuvik Gas and Ikhil Joint Venture) providing natural gas to the Town of Inuvik, Northwest Territories;
- Fully contracted 102 MW Bear Mountain Wind Park located near Dawson Creek, British Columbia (the "Bear Mountain Wind Park") owned by BMWLP and BMWPC; and
- Approximately 10 percent indirect equity interest in the capital of Coast LP and Coast GP which indirectly own three fully contracted 303 MW run of river hydroelectric power generation assets in northwest British Columbia (the "Northwest Hydro Facilities") by way of the CMH Group.

Pursuant to the Purchase and Sale Agreement, the Company also acquired on October 18, 2018, the indebtedness that AUGI and PNG owed to AltaGas and certain of its subsidiaries in the aggregate amount of approximately $481.6 million (the "Acquired Indebtedness").

The Company satisfied the purchase price of $889.1 million for the Acquired Assets and Acquired Indebtedness by issuing to AltaGas the following:

- 5,912,857 Common Shares;
- An unsecured promissory note dated October 18, 2018 bearing interest at 4.5 percent per annum in the principal amount of approximately $316.3 million (the "Purchase Price Short-Term Note") which was to be repaid upon closing of the initial public offering by ACI of its Common Shares completed on October 25, 2018 (the "IPO");
- An unsecured promissory note dated October 18, 2018 bearing interest at 3.3 percent per annum in the principal amount of $35.9 million (adjustable to approximately $34.0 million in the event the Over-Allotment Option is exercised in full) (the "Over-Allotment Note") which was to be repaid no later than 30 days after closing of the IPO; and
- An unsecured promissory note dated October 18, 2018 bearing interest at 4.5 percent per annum in the principal amount of $351.2 million (the "Purchase Price Long-Term Note") with a term of 30 months, the interest to be increased by 0.25 percent on the 18 and 24 month anniversaries of the issuance date.

The Purchase Price Short-Term Note, the Over-Allotment Note, and the Purchase Price Long-Term Note have been fully repaid as at December 31, 2018.

Immediately prior to the Acquisition:

- The Company paid an eligible dividend of $31.0 million to AltaGas;
- BMWLP distributed cash of $64.6 million to AltaGas; and
- AUGI repaid indebtedness of $28.4 million to AltaGas.

Initial Public Offering of Common Shares

On October 25, 2018, the Company completed its IPO, issuing 16,500,000 Common Shares at a price of $14.50 per Common Share for gross proceeds of $239.3 million.

In connection with the IPO, the Company granted to the underwriters of the IPO an over-allotment option (the "Over-Allotment Option"), exercisable at the underwriters' discretion at any time, in whole or in part, until 30 days following the closing of the IPO, to purchase at $14.50 per Common Share up to an additional 2,475,000 Common Shares (representing 15 percent of the Common Shares offered under the IPO) to cover over-allotments, if any, and for market stabilization purposes. On November 21, 2018, the Over-Allotment Option was exercised in full for additional gross proceeds of $35.9 million.

Upon closing of the IPO and the exercise of the Over-Allotment Option, 30,000,000 Common Shares were issued and outstanding, of which AltaGas owned approximately 36.8 percent. The Company ceased to be a wholly-owned subsidiary of AltaGas upon completion of the IPO on October 25, 2018.

The net proceeds of the IPO were $223.7 million after deducting the underwriters' fee of $12.6 million and approximately $3.0 million in other expenses. The net proceeds from the exercise of the Over-Allotment Option were $34.0 million after deducting the underwriters' fee of $1.8 million and other expenses of $0.1 million. In accordance with the Purchase and Sale Agreement, ACI used the net proceeds of the IPO, including the proceeds from the exercise of the Over-Allotment Option, to:

- Repay in full a note issued by ACI to AltaGas bearing interest at 5.0 percent per annum in the principal amount of $157.4 million issued in connection with a return on capital on the Common Shares immediately prior to the Acquisition;
- Repay a portion of the Purchase Price Short-Term Note with the remaining portion of the Purchase Price Short-Term Note being repaid with the proceeds of the syndicated term loan; and
- Repay in full the Over-Allotment Note. Per the terms of the Over-Allotment Note, if the Over-Allotment Option was exercised, the principal amount would be reduced by the amount of the underwriters' fee and other expenses of approximately $1.9 million. On November 21, 2018, the Company repaid the Over-Allotment Note in full.

2019 FINANCIAL HIGHLIGHTS

(Normalized EBITDA, normalized funds from operations, normalized net income, net debt, and net debt to total capitalization ratio are non-GAAP financial measures. Please see the *"Non-GAAP Financial Measures"* section of this MD&A.)

- Net income after taxes was $42.1 million ($1.40 per Common Share) compared to $45.3 million ($1.51 per Common Share) in 2018.
- Normalized net income was $45.3 million ($1.51 per Common Share), an increase of 8 percent compared to $41.8 million ($1.39 per Common Share) in 2018.
- Operating income was $73.4 million, a decrease of 3 percent compared to $76.0 million in 2018.
- Normalized EBITDA was $113.5 million, an increase of 8 percent compared to $105.2 million in 2018.
- Normalized funds from operations were $79.9 million ($2.66 per Common Share), a 9 percent decrease compared to $88.1 million ($2.94 per Common Share) in 2018.
- Net debt was $669.5 million as at December 31, 2019, compared to $643.8 million as at December 31, 2018.
- Net debt to total capitalization ratio was 51.9 percent as at December 31, 2019, compared to 51.4 percent as at December 31, 2018.
- Rate base as at December 31, 2019 was $941 million inclusive of construction work in progress, compared to $895 million as at December 31, 2018.

- On April 3, 2019, ACI completed the issuance of $250 million of medium-term notes ("MTNs") with a coupon rate of 3.15 percent (3.151 percent yield to maturity) and a maturity date of April 6, 2026.
- On June 28, 2019, PNG submitted an application to the BCUC for approval of a large volume industrial transportation rate required in its proposed process for allocation of reactivated capacity on its existing pipeline system (the "PNG Reactivation Application").
- On August 7, 2019, the Board of Directors approved a 9.5 percent increase to the quarterly dividend to $0.26 per Common Share, payable on September 30, 2019.
- On October 21, 2019, ACI announced it had entered into the Arrangement Agreement pursuant to which the Consortium will indirectly acquire through the Purchaser, all of the issued and outstanding Common Shares of ACI for $33.50 in cash per Common Share.
- On November 4, 2019, HGL filed an application with the Nova Scotia Utility and Review Board ("NSUARB") requesting to extend its Customer Retention Program ("CRP") to the end of 2023.
- On November 29, 2019, PNG and PNG(NE) submitted the 2020 and 2021 revenue requirement applications seeking interim rate increases effective January 1, 2020. PNG received BCUC approval for the interim rate increases on December 18, 2019.

HIGHLIGHTS SUBSEQUENT TO YEAR END

- On February 13, 2020, ACI extended the maturity date of the Revolving Credit Facility to December 31, 2023.
- On February 18, 2020, ACI received approval for the Arrangement from the AUC.
- On February 28, 2020, PNG received approval for the PNG Reactivation Application from the BCUC.

OVERVIEW OF THE BUSINESS

ACI has three reporting segments:

- Utilities, which owns and operates utility assets that deliver natural gas to end-users in Alberta, British Columbia and Nova Scotia. ACI also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. In aggregate, the utilities have approximately $941 million of rate base as at December 31, 2019 inclusive of construction work in progress and serve approximately 130,000 customers across Canada.
- Renewable Energy, which includes the Bear Mountain Wind Park and an approximately 10 percent indirect interest in the entities that own the Northwest Hydro Facilities.
- Corporate, which primarily includes the cost of providing shared services, financing and access to capital, and general corporate support.

Utilities segment

Alberta

AUI owns and operates a regulated natural gas distribution utility in Alberta. As at December 31, 2019, AUI served approximately 80,500 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. AUI's rate base as at December 31, 2019 was approximately $396 million. On August 2, 2018, the AUC approved an ROE of 8.5 percent on 39 percent equity for 2018, 2019 and 2020.

AUI operates in a stable regulatory environment under a Performance-Based Regulation ("PBR") framework, first introduced for the initial 2013 to 2017 PBR plan term. Effective January 1, 2018, the AUC approved a second PBR plan term from 2018 to 2022 ("PBR 2"). Under the PBR 2 plan, rates continue to be set under a revenue cap per customer formula with annual adjustments for customer growth and inflation less expected productivity improvements. As revenues are generally decoupled from costs, a utility is incentivized to achieve cost efficiencies during the PBR plan term.

In addition, the PBR 2 plan continues to allow for recovery of costs determined to flow through directly to customers, recovery of items related to material exogenous events, and re-opener threshold provisions that allow an application to be re-opened in order to address specific problems with the design or operation of the PBR plan. Incremental capital funding is largely determined formulaically based on historical capital additions with an additional mechanism available for cost recovery of specific capital projects that are extraordinary, not previously included in rate base, and required by a third party ("Type 1 Capital Tracker"). As a result of its formulaic design, the PBR framework provides a level of regulatory certainty throughout the PBR period, allowing the utility to manage its costs and to allocate and plan capital spending accordingly.

On December 20, 2018, the AUC approved rates on an interim basis for the construction of 17 km of new pipeline to replace a lateral pipeline that is being abandoned by NOVA Gas Transmission Ltd. (the "Etzikom Lateral Project"). The Etzikom lateral pipeline serves approximately 1,715 of AUI's customers in southeast Alberta, including rural areas surrounding the City of Medicine Hat and extending south to the hamlet of Etzikom and surrounding rural areas. Construction of the Etzikom Lateral

Project was completed in the fourth quarter of 2019 and the total cost of the project was approximately $9.7 million. AUI expects the AUC to issue a final decision on whether or not the project meets the Type 1 Capital Tracker criteria under the PBR 2 plan in 2020. Any difference between interim-approved and actual approved revenue requirements are expected to be collected or refunded through 2021 annual PBR rates.

On December 20, 2019, the AUC issued a decision regarding AUI's 2018 depreciation study application (the "AUI Depreciation Study"). The applied for service life depreciation rate changes were approved as filed while the AUC approved lesser increases than applied for regarding net salvage rates. The change in depreciation rates was effective January 1, 2018 and the cumulative impact has been reflected in the Company's fourth quarter 2019 results.

British Columbia

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (the "Western System") and PNG(N.E.), PNG's wholly-owned subsidiary, owns and operates a distribution utility in northeastern British Columbia (the "Northeast System"). As at December 31, 2019, PNG served approximately 42,100 customers. Approximately 87 percent of PNG's total customers are residential. PNG's rate base as at December 31, 2019 was approximately $232 million.

PNG operates under a cost of service regulatory framework affording PNG an opportunity to recover all prudently incurred costs and earn a rate of return on its deemed common equity. The allowed ROE and deemed capital structure is approved by the BCUC and is based off the low risk benchmark utility. The allowed ROE for the Western System and the Northeast System (Tumbler Ridge) is 9.50 percent and for the Northeast System (Fort St. John/Dawson Creek) is 9.25 percent. The approved common equity ratio for the Western System and the Northeast System (Tumbler Ridge) is 46.5 percent and for the Northeast System (Fort St. John/Dawson Creek) is 41 percent.

In November 2017, PNG submitted revenue requirements applications with the BCUC for 2018 and 2019 and received approvals for interim and refundable delivery rate increases effective January 1, 2018. The BCUC issued its decisions in August 2018 and approved permanent delivery rate decreases of approximately 1.8 percent for each of 2018 and 2019 for customers in the Western System, permanent delivery rate increases of approximately 6 percent for each of 2018 and 2019 for customers in the Northeast System (Fort St. John/Dawson Creek) service areas, as well as permanent delivery rate increases of approximately 18 percent for each of 2018 and 2019 for customers in the Northeast System (Tumbler Ridge) service area, compared to 2017 rates. The BCUC also directed PNG to include a provision for negative salvage in its depreciation expense commencing in 2019 and sought input from PNG on the transitional period to effect this accounting change. PNG requested and received BCUC approval on November 26, 2018 for a five year transition period for the inclusion of negative salvage accounting. The delivery rate increases noted above do not include the impact of negative salvage accounting. Taking into consideration negative salvage, the 2019 permanent delivery rates are decreased by approximately 0.3 percent for customers in the Western System, increased by approximately 7 percent in the Northeast System (Fort St. John/Dawson Creek) service areas and increased by approximately 20 percent in the Northeast System (Tumbler Ridge) service area.

On November 29, 2019, PNG and PNG(NE) submitted the 2020 and 2021 revenue requirement applications seeking interim rate increases effective January 1, 2020. For each of 2020 and 2021, PNG is seeking approximately 2 percent delivery rate increase for customers in the Western System, approximately 11 percent delivery rate increase for customers in the Northeast System (Fort St. John/Dawson Creek) service areas and approximately 4 percent delivery rate increase for customers in the Northeast System (Tumbler Ridge) service areas, compared to 2019 rates. PNG received BCUC approval for the interim rate changes on December 18, 2019. Amendments to the applications were filed on February 28, 2020 and PNG expects the BCUC decision on permanent rates in the third quarter of 2020.

On June 28, 2019, PNG submitted the PNG Reactivation Application. The proposed reactivation involves natural gas deliveries from Station 4a on the Enbridge Westcoast Energy Inc. southern mainline near Summit Lake, British Columbia to three termination points: Terrace, Kitimat, and Prince Rupert, British Columbia.

On February 28, 2020, PNG received BCUC approval for the PNG Reactivation Application and now plans to conduct a binding open season auction where shippers will have the opportunity to bid on capacity of up to approximately 88 million standard cubic feet per day based on either firm transportation service agreements ("TSA") or reserve capacity through transportation reservation agreements. PNG has garnered strong interest from a number of potential shippers. Provided there are sufficient shipper commitments backed by TSAs, PNG would commence system reactivation and recommissioning work to prepare for returning the system back to full utilization, subject to BCUC approvals. Depending on shipper demands and the requested delivery points, PNG estimates the capital cost for the reactivation, recommissioning and system reinforcement could be up to $120 million.

Nova Scotia

HGL has the exclusive rights to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality. As at December 31, 2019, HGL's customer base is approximately 7,700 customers. HGL has a mix of residential, small commercial, large commercial and industrial customers. HGL's rate base as at December 31, 2019 was approximately $313 million.

HGL operates under a cost of service regulatory framework where prudently incurred investments earn a rate of return on its deemed capital structure which is approved by the NSUARB. For 2019 and 2018, HGL's approved regulated ROE is 11 percent with an approved deemed capital structure of 45 percent equity. In order to lower pricing for a portion of its commercial customers, HGL filed a CRP application with the NSUARB in March 2016 requesting a decrease in distribution rates for commercial customers with consumption between 500 and 4,999 GJ per year and allowing for flexible rate increases from time to time for these customers up to their previously approved distribution rates. HGL also requested a suspension of depreciation and a deferral of an additional approximately 25 percent of maintenance and administrative expenses while the program is in place. In September 2016, the NSUARB approved HGL's CRP application. The approval included all of the items requested by HGL as well as a reduction to residential customer rates of $0.50 per GJ during the 2016 to 2017 and 2017 to 2018 winter seasons and a return on the deferred depreciation and operating expense balances arising from the CRP of 4 percent.

The competitive position of natural gas pricing relative to propane improved in the Atlantic region throughout 2017 and into early 2018. Through enhanced gas procurement strategies and changes in market fundamentals, the average price of natural gas for HGL customers declined by over 20 percent in 2017 compared to 2016, while the 2017 Sarnia benchmark price for propane increased by over 30 percent compared to 2016. Accordingly, in November of 2017 and in June and November of 2018, HGL exercised the flexibility provided for in the CRP to increase the rates that were previously reduced as part of the CRP, which has partially restored the rates to previously approved cost of service levels.

Due to delays in gas infrastructure projects that are expected to further reduce natural gas prices in the Maritimes, on November 4, 2019, HGL filed an application with the NSUARB requesting to extend its CRP that was set to expire at the end of 2020 to the end of 2023 and to significantly reduce the degree of deferral currently approved. In addition to retaining pricing flexibility to adjust rates for certain commercial customers, HGL also requested to change the CRP deferral mechanism to defer amounts equivalent to the price discount provided to customers, rather than the current practice of suspension of depreciation and 50 percent capitalization of operating, maintenance and administrative expenses. If approved, future amounts deferred under the CRP program are expected to be lower than the current practice. HGL filed its final submission to the NSUARB on January 29, 2020 and is currently awaiting NSUARB's decision.

For its regulated operations, HGL has approval from the NSUARB to use a Revenue Deficiency Account ("RDA") until it is fully recovered, subject to a maximum of $50 million, which may be increased subject to approval by the NSUARB. The RDA is revenue required to afford HGL the opportunity to earn the rates of return on its rate base, as approved by the NSUARB. In periods where the actual revenue billed is less than the revenue required to earn the approved rates of return, the RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rates of return and the RDA is drawn down.

On June 1, 2018, HGL received approval from the NSUARB to enter into a long-term (22 year) contract with Portland Natural Gas Transmission System for natural gas transportation capacity from the Dawn Hub in Ontario to Nova Scotia on the Maritimes and Northeast Pipeline System and recover associated costs of the contract from its customers through regulated rates. The contract commenced on November 1, 2018.

In 2014, HGL signed an agreement with Enbridge Inc. for the Atlantic Bridge Expansion Project on the Algonquin Gas Transmission pipeline system. The contract is a 15-year commitment for 10,550 GJ per day of transportation that provides HGL an opportunity to diversify suppliers and provide access to another supply basin until the end of its term. The Atlantic Bridge Expansion Project is expected to be in-service in late 2020.

Inuvik Gas Ltd. & Ikhil Joint Venture
The Company has an approximate one-third interest in Inuvik Gas and the Ikhil Joint Venture natural gas reserves, which have historically supplied Inuvik Gas with natural gas for the Town of Inuvik. With the Ikhil Joint Venture natural gas reserves approaching the end of their life, a propane air mixture system producing synthetic natural gas was implemented as the main source of energy supply for Inuvik Gas with the Ikhil Joint Venture serving as a back-up. In December 2016, Inuvik Gas notified the Town of Inuvik of its intention to terminate the gas distribution franchise agreement effective December 2018. The franchise agreement was terminated on December 8, 2018. Through an in-person meeting in December 2018, Inuvik Gas agreed to continue to provide service to its customers in accordance with the previous franchise agreement and the Northwest Territories Public Utilities Board approved terms and conditions of service as Inuvik Gas and the Town of Inuvik continue negotiations to transition ownership of Inuvik Gas to the Town of Inuvik. The Company and its joint venture partners will continue to own and operate the Ikhil Joint Venture.

Renewable Energy Segment

Bear Mountain Wind Park
The Bear Mountain Wind Park near Dawson Creek, British Columbia is a 102 MW generating wind facility consisting of 34 turbines, a substation and transmission and collector lines, which is connected to the BC Hydro transmission grid. All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year EPA expiring in 2034 with an escalation factor of 50 percent of Canadian CPI.

Northwest Hydro Facilities
The Northwest Hydro Facilities, in which the Company has a 10 percent indirect equity interest, is located in Tahltan First Nation territory approximately 1,000 kilometers northwest of Vancouver, British Columbia, are comprised of the Forrest Kerr Hydroelectric Facility ("Forest Kerr"), the McLymont Creek Hydroelectric Facility ("McLymont Creek"), the Volcano Creek Hydroelectric Facility ("Volcano Creek") and a substation and transmission line and related facilities. The facilities have total installed capacity of 303 MW. These facilities are each underpinned by 60-year EPAs, fully indexed to BC CPI. The EPA for Forrest Kerr and Volcano Creek expire in 2074 and the EPA for McLymont Creek expires in 2075. Impact benefit agreements are in place with the Tahltan First Nation for all three facilities, to facilitate a cooperative and mutually beneficial relationship.

OUTLOOK AND CAPITAL PROGRAM

Over the 2020 to 2024 time period, ACI expects to achieve approximately six percent compound annual normalized net income growth. Over this period, ACI expects to spend $450 to $525 million at its utilities. The expected capital program includes the PNG Reactivation Project as well as investments in system betterment projects to maintain the safety and reliability of ACI's utility infrastructure, new business opportunities and technology improvements. In 2020, ACI expects capital spend to be in the range of $75 to $85 million.

SELECTED FINANCIAL INFORMATION

The following tables summarize key financial results:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized EBITDA(1)(2)	**40.1**	34.2	**113.5**	105.2
Operating income	**26.4**	27.2	**73.4**	76.0
Net income after taxes	**16.1**	20.8	**42.1**	45.3
Normalized net income(1)	**18.6**	20.0	**45.3**	41.8
Total assets	**1,582.3**	1,515.5	**1,582.3**	1,515.5
Total long-term liabilities	**852.4**	815.4	**852.4**	815.4
Net additions to property, plant and equipment	**27.4**	24.7	**69.7**	68.2
Dividends declared(3)	**7.8**	5.2	**29.9**	5.2
Cash from operations(4)	**17.2**	26.4	**76.6**	89.9
Normalized funds from operations(1)(4)	**34.7**	28.6	**79.9**	88.1

	Three Months Ended December 31		Year Ended December 31	
($ per Common Share, except Common Shares outstanding)	**2019**	2018	**2019**	2018
Net income after taxes - basic	**0.54**	0.69	**1.40**	1.51
Net income after taxes - diluted	**0.53**	0.69	**1.40**	1.51
Normalized net income - basic(1)	**0.62**	0.67	**1.51**	1.39
Dividends declared(3)	**0.2600**	0.1744	**0.9950**	0.1744
Cash from operations(4)	**0.57**	0.88	**2.55**	3.00
Normalized funds from operations(1)(4)	**1.16**	0.95	**2.66**	2.94
Weighted average number of Common Shares outstanding - basic (millions)(5)	**30.0**	30.0	**30.0**	30.0

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(2) Effective January 1, 2019, ACI revised the calculation of normalized EBITDA to incorporate ACI's proportionate share of normalized EBITDA from its equity investments instead of just the equity pickup. The comparative periods have been revised to conform to the current period presentation. Please refer to "*Non-GAAP Financial Measures*" section of this MD&A.

(3) Dividend declared per Common Share after the completion of the IPO.

(4) Inclusive of a special distribution related to the investment in the Northwest Hydro Facilities of $20.3 million during the year ended December 31, 2018, which was redistributed to AltaGas prior to the Acquisition.

(5) For comparative purposes, the Common Shares issued under the IPO including the Over-Allotment Option, have been assumed to be outstanding as of January 1, 2018.

The following table summarizes ACI's consolidated results:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Revenue	**101.2**	95.3	**326.3**	309.1
Cost of sales	**(38.2)**	(38.4)	**(125.8)**	(117.3)
Operating and administrative expense	**(28.3)**	(23.7)	**(100.4)**	(92.5)
Accretion expense	**—**	—	**(0.1)**	(0.1)
Depreciation and amortization expense	**(9.6)**	(6.9)	**(31.7)**	(28.9)
Income from equity investments	**2.1**	0.1	**7.4**	4.2
Unrealized gain (loss) on foreign exchange contract	**(0.7)**	0.8	**(2.2)**	1.7
Other loss	**—**	—	**(0.1)**	(0.1)
Foreign exchange loss	**(0.1)**	—	**—**	(0.1)
Operating income	**26.4**	27.2	**73.4**	76.0
Interest expense	**(6.9)**	(7.6)	**(26.9)**	(28.5)
Income tax recovery (expense)	**(3.4)**	1.3	**(4.4)**	(2.2)
Net income after taxes	**16.1**	20.8	**42.1**	45.3

Three Months Ended December 31

Normalized EBITDA for the three months ended December 31, 2019 was $40.1 million, an increase of $5.9 million relative to the same period in 2018 primarily due to rate base growth, higher approved rates, higher normalized EBITDA from the investment in the Northwest Hydro Facilities, higher generation at the Bear Mountain Wind Park and colder weather in Alberta, partially offset by higher operating and administrative expenses and warmer weather in Nova Scotia.

Operating income for the three months ended December 31, 2019 was $26.4 million, a decrease of $0.8 million relative to the same period in 2018 primarily due to an unrealized loss on foreign exchange contracts in comparison to a gain in the same period in 2018, higher depreciation and amortization expense, partially offset by the same factors as the increase in normalized EBITDA as discussed above.

Operating and administrative expense for the three months ended December 31, 2019 was $28.3 million, an increase of $4.6 million from the same period in 2018 mainly due to transaction costs incurred in respect of the Arrangement and higher employee related costs primarily from inflationary salary increases and employee incentive programs, and higher contractor and consulting fees.

Depreciation and amortization expense for the three months ended December 31, 2019 was $9.6 million, an increase of $2.7 million from the same period in 2018 mainly due to capital assets being put into service and approval of the AUI Depreciation Study in December 2019.

Interest expense for the three months ended December 31, 2019 was $6.9 million compared to $7.6 million in the same period in 2018. The decrease of $0.7 million was mainly due to lower average interest rates, partially offset by a higher average debt balance outstanding as a result of incremental borrowing to capitalize ACI as a standalone entity.

Income tax expense for the three months ended December 31, 2019 was $3.4 million, compared to income tax recovery of $1.3 million in the same period in 2018 primarily due to higher taxable income from the Company's investment in the Northwest Hydro Facilities, the income tax impact from the approval of the AUI Depreciation Study in December 2019 and the absence of true-up adjustments that were made in 2018 to transition ACI to a standalone entity.

Normalized net income for the three months ended December 31, 2019 was $18.6 million, a decrease of $1.4 million relative to the same period in 2018 mainly due to higher income tax expense and higher depreciation and amortization expense, partially offset by the same factors as the increase in normalized EBITDA discussed above and lower interest expense.

Net income after taxes for the three months ended December 31, 2019 was $16.1 million, a decrease of $4.7 million compared to the same period in 2018. The decrease was due to the same factors as the decrease in operating income discussed above and higher income tax expense, partially offset by lower interest expense.

Normalized funds from operations for the three months ended December 31, 2019 was $34.7 million, an increase of $6.1 million relative to the same period in 2018, primarily due to rate base growth, higher approved rates, higher distribution from the investment in the Northwest Hydro Facilities, colder weather in Alberta, higher generation volume at the Bear Mountain Wind Park, and lower interest expense, partially offset by higher current income tax expense, higher operating and administrative expense, and warmer weather in Nova Scotia.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2019 was $113.5 million, an increase of $8.3 million relative to the same period in 2018, primarily due to rate base growth, higher approved rates, colder weather in Nova Scotia, higher normalized EBITDA from the investment in the Northwest Hydro Facilities, partially offset by higher operating and administrative expense.

Operating income for the year ended December 31, 2019 was $73.4 million, a decrease of $2.6 million compared to the same period in 2018, primarily due to the absence of a one-time revenue of approximately $1.8 million related to the receipt of funds in 2018 from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods, an unrealized loss on foreign exchange contracts compared to a gain in the prior year, and higher depreciation and amortization expense, partially offset by the same factors as the increase in normalized EBITDA as discussed above.

Operating and administrative expense for the year ended December 31, 2019 was $100.4 million, an increase of $7.9 million from 2018 mainly due to transaction costs incurred in respect of the Arrangement, higher employee related costs primarily from inflationary salary increases and employee incentive programs, and higher contract and consultant expenses.

Depreciation and amortization expense for the year ended December 31, 2019 was $31.7 million, an increase of $2.8 million from 2018 primarily due to capital assets being put into service and approval of the AUI Depreciation Study in December 2019, partially offset by a write-down of unregulated plant assets in 2018.

Interest expense for the year ended December 31, 2019 was $26.9 million compared to $28.5 million in 2018. The decrease of $1.6 million was mainly due to lower average interest rates, partially offset by a higher average debt balance outstanding as a result of incremental borrowing to capitalize ACI as a standalone entity.

Income tax expense for the year ended December 31, 2019 was $4.4 million, an increase of $2.2 million compared to 2018, primarily due to higher taxable income from the Company's investment in the Northwest Hydro Facilities, the income tax impact from the approval of the AUI Depreciation Study in December 2019, and the absence of true-up adjustments that were made in 2018 to transition ACI to a standalone entity, partially offset by the one-time deferred income tax recovery related to the reduction in the Alberta statutory tax rate in June 2019 and the decrease in current income tax expense due to accelerated tax deductions related to property, plant and equipment ("PP&E").

Normalized net income for the year ended December 31, 2019 was $45.3 million, an increase of $3.5 million relative to the same period in 2018, primarily due to the same factors that resulted in an increase in normalized EBITDA discussed above and the decrease in interest expense, partially offset by an increase in depreciation and amortization expense and higher income tax expense.

Net income after taxes for the year ended December 31, 2019 was $42.1 million, a decrease of $3.2 million from the same period in 2018 due to the same factors as the decrease in operating income discussed above and higher income tax expense, partially offset by lower interest expense.

Normalized funds from operations for the year ended December 31, 2019 was $79.9 million, a decrease of $8.2 million relative to the same period in 2018, primarily due to the absence of a special distribution of $20.3 million received in 2018 from the equity investment in the Northwest Hydro Facilities, which was redistributed to AltaGas prior to the Acquisition, lower wind generation at the Bear Mountain Wind Park, and higher operating and administrative expense, partially offset by rate base growth, higher approved rates, colder weather in Nova Scotia, and lower interest and current income tax expense.

Please refer to the "*Liquidity*" section of this MD&A for a discussion of changes in cash from operating activities.

RESULTS BY REPORTING SEGMENT

Normalized EBITDA by Reporting Segment (1)(2)

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Utilities	**$ 34.3**	$ 29.7	**$ 95.1**	$ 87.8
Renewable Energy	**6.8**	4.7	**21.1**	17.6
Corporate	**(1.0)**	(0.2)	**(2.7)**	(0.2)
	$ 40.1	$ 34.2	**$ 113.5**	$ 105.2

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(2) Effective January 1, 2019, ACI revised the calculation of normalized EBITDA to incorporate ACI's proportionate share of normalized EBITDA from its equity investments instead of just the equity pick-up. The comparative periods have been revised to conform to the current period presentation. Please refer to "*Non-GAAP Financial Measures*" section of this MD&A.

Operating Income (Loss) by Reporting Segment

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Utilities	**$ 25.8**	$ 25.4	**$ 68.3**	$ 69.5
Renewable Energy	**4.0**	2.0	**10.1**	6.8
Corporate	**(3.4)**	(0.2)	**(5.0)**	(0.3)
	$ 26.4	$ 27.2	**$ 73.4**	$ 76.0

UTILITIES SEGMENT REVIEW

Financial results

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Revenue (1)	**$ 96.0**	$ 90.6	**$ 311.5**	$ 292.2
Cost of sales	**(38.2)**	(38.4)	**(125.6)**	(117.1)
Operating and administrative expense	**(23.5)**	(22.5)	**(90.7)**	(87.1)
Normalized EBITDA from equity investment	**—**	0.1	**—**	—
Other loss	**—**	(0.1)	**(0.1)**	(0.2)
Normalized EBITDA (2)(3)	**$ 34.3**	$ 29.7	**$ 95.1**	$ 87.8
Unrealized gain (loss) on foreign exchange contracts	**(0.7)**	0.8	**(2.2)**	1.7
Depreciation and amortization expense	**(7.8)**	(5.1)	**(24.5)**	(21.7)
Accretion expense	**—**	—	**(0.1)**	(0.1)
Part VI.1 revenue from AltaGas	**—**	—	**—**	1.8
Operating income	**$ 25.8**	$ 25.4	**$ 68.3**	$ 69.5

(1) Excludes Part VI.1 revenue from AltaGas of approximately $1.8 million for the year ended December 31, 2018.

(2) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(3) Effective January 1, 2019, ACI revised the calculation of normalized EBITDA to incorporate ACI's proportionate share of normalized EBITDA from its equity investments instead of just the equity pick-up. The comparative periods have been revised to conform to the current period presentation. Please refer to "*Non-GAAP Financial Measures*" section of this MD&A.

Operating statistics

	Three Months Ended December 31		Year Ended December 31	
	2019	2018	**2019**	2018
Natural gas deliveries - end-use (PJ)	**11.2**	11.1	**35.0**	34.3
Natural gas deliveries - transportation (PJ)	**1.5**	1.4	**5.8**	5.7
Degree day variance from normal - AUI (%)(1)	**1.3**	(4.3)	**6.6**	6.7
Degree day variance from normal - HGL (%)(1)	**2.8**	13.0	**3.5**	(0.6)

(1) A degree day for AUI and HGL is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at HGL. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG, as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

Regulatory Metrics

Year ended December 31	**2019**	2018
Average approved ROE (%)(1)	**9.6**	9.6
Rate base ($ millions)(2)(3)	**941**	895

(1) ROE is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base.

(2) Rate base is indicative of the earning potential of each utility over time. Approved revenue requirements for each utility is typically based on the rate base as approved by the regulator for the respective rate application, but may differ from the rate base indicated above.

(3) Inclusive of construction work in progress.

Three Months Ended December 31

Revenue increased by $5.4 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to rate base growth, higher approved rates, and colder weather in Alberta, partially offset by warmer weather in Nova Scotia.

Normalized EBITDA increased by $4.6 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to higher revenue discussed above, partially offset by higher employee related costs primarily from inflationary salary increases, and higher contractor and consulting fees.

Operating income increased by $0.4 million for the three months ended December 31, 2019 compared to the same period in 2018, primarily due to higher revenue discussed above, partially offset by higher depreciation and amortization expense as a result of the approval of the AUI Depreciation Study in December 2019 and an unrealized loss on foreign exchange contracts compared to a gain in the same period of 2018.

Year Ended December 31

Revenue increased by $19.3 million for the year ended December 31, 2019 compared to the same period in 2018 primarily due to rate base growth, higher approved rates, colder weather in Nova Scotia and flow through of higher gas supply costs to customers.

Normalized EBITDA increased by $7.3 million for the year ended December 31, 2019 compared to the prior year, primarily due to higher revenue discussed above, partially offset by higher employee related costs primarily from inflationary salary increases, and higher contractor and consulting fees.

Operating income decreased by $1.2 million for the year ended December 31, 2019 compared to the prior year, due to higher depreciation and amortization expense mainly due to the AUI Depreciation Study being approved in December 2019, an unrealized loss on foreign exchange contracts compared to a gain in the prior year, and the absence of the one-time revenue of approximately $1.8 million recognized in 2018 related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers, partially offset by the same factors as the increase in normalized EBITDA discussed above.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

($ millions)	Three Months Ended December 31 2019	2018	Year Ended December 31 2019	2018
Revenue	**$ 5.2**	$ 4.8	**$ 14.8**	$ 15.2
Cost of sales	**—**	—	**(0.2)**	(0.2)
Operating and administrative expense	**(1.5)**	(1.0)	**(4.7)**	(5.2)
Normalized EBITDA from equity investment	**3.1**	0.9	**11.2**	7.8
Normalized EBITDA[(1)(2)]	**$ 6.8**	$ 4.7	**$ 21.1**	$ 17.6
Depreciation and amortization expense	**(1.8)**	(1.8)	**(7.2)**	(7.2)
Accretion and depreciation and amortization expense from equity investment	**(1.0)**	(0.9)	**(3.8)**	(3.6)
Operating income	**$ 4.0**	$ 2.0	**$ 10.1**	$ 6.8

(1) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(2) Effective January 1, 2019, ACI revised the calculation of normalized EBITDA to incorporate ACI's proportionate share of normalized EBITDA from its equity investments instead of just the equity pick-up. The comparative periods have been revised to conform to the current period presentation. Please refer to "*Non-GAAP Financial Measures*" section of this MD&A.

Operating statistics

	Three Months Ended December 31 2019	2018	Year Ended December 31 2019	2018
Bear Mountain Wind Park power sold (GWh)	**51.1**	42.2	**141.9**	143.7
Northwest Hydro Facilities power sold (GWh)[(1)(2)]	**23.2**	10.5	**120.5**	101.4

(1) Representing 10 percent of the total power sold by the Northwest Hydro Facilities.

(2) Inclusive of 2.7 GWh of deemed energy for the year ended December 31, 2019 related to BC Hydro's curtailment.

Three Months Ended December 31

Revenue increased by $0.4 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to higher generation at the Bear Mountain Wind Park.

Normalized EBITDA increased by $2.1 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to higher generation at the Bear Mountain Wind Park and higher normalized EBITDA from the Northwest Hydro Facilities, partially offset by higher operating expenses.

Operating income increased by $2.0 million for the three months ended December 31, 2019 compared to the same period in 2018 due to the same factors as the increase in normalized EBITDA discussed above.

During the three months ended December 31, 2019, ACI recorded $2.1 million of equity income from its investment in the Northwest Hydro Facilities, compared to $nil in the same period of 2018 mainly due to higher generation.

For the year ended December 31

Revenue decreased by $0.4 million for the year ended December 31, 2019 compared to the same period in 2018 primarily due to lower generation at the Bear Mountain Wind Park.

Normalized EBITDA increased by $3.5 million for the year ended December 31, 2019 compared to the same period in 2018 mainly due to higher normalized EBITDA from the Northwest Hydro Facilities, and lower shared service allocation from the Corporate segment, partially offset by lower generation at the Bear Mountain Wind Park.

Operating income increased by $3.3 million for the year ended December 31, 2019 compared to the prior year due to the same factors discussed above for the increase in normalized EBITDA, partially offset by higher depreciation expense incurred at the Northwest Hydro Facilities due to additions in property, plant and equipment.

During the year ended December 31, 2019, ACI recorded $7.4 million of equity income from its investment in the Northwest Hydro Facilities, compared to $4.2 million in 2018. The increase was mainly due to higher generation and contracted price escalation at the Northwest Hydro Facilities.

CORPORATE SEGMENT REVIEW

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Operating and administrative expense[1]	**$ (1.0)**	$ (0.3)	**$ (2.7)**	$ (0.3)
Other income	**—**	0.1	**—**	0.1
Normalized EBITDA[2]	**$ (1.0)**	$ (0.2)	**$ (2.7)**	$ (0.2)
Foreign exchange loss	**(0.1)**	—	**—**	(0.1)
Transaction costs	**(2.3)**	—	**(2.3)**	—
Operating loss	**$ (3.4)**	$ (0.2)	**$ (5.0)**	$ (0.3)

(1) Excludes transaction costs of approximately $2.3 million in respect of the Arrangement for the three and twelve months ended December 31, 2019.

(2) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

For the three and twelve months ended December 31, 2019, normalized EBITDA was a loss of $1.0 million and $2.7 million, respectively (2018 - $0.2 million for both periods). Expenses incurred by the Corporate segment in 2019 are related to employee incentive programs tied to ACI's share price performance, business development activities, and costs associated with providing corporate shared services. For the three and twelve months ended December 31, 2019, corporate costs of $1.9 million and $7.2 million, respectively, were allocated to ACI's operating segments compared to $1.9 million and $8.4 million, respectively, for the same periods in 2018.

For the three and twelve months ended December 31, 2019, operating loss was $3.4 million and $5.0 million, respectively (2018 - $0.2 million and $0.3 million, respectively). The Company incurred transaction costs of approximately $2.3 million in 2019 in respect of the Arrangement.

SUMMARY OF SELECTED QUARTERLY RESULTS [1]

The following table sets forth unaudited quarterly information for each of the eight quarters from the quarter ended March 31, 2018 to the quarter ended December 31, 2019.

($ millions, except per Common Share amounts)	**Q4-19**	Q3-19	Q2-19	Q1-19
Revenue	**101.2**	45.2	61.3	118.6
Normalized net income[2]	**18.6**	2.4	3.8	20.4
Net income after taxes	**16.1**	2.8	3.9	19.2
Net income after taxes per Common Share - basic ($)[3]	**0.54**	0.09	0.13	0.64
Net income after taxes per Common Share - diluted ($)[3]	**0.53**	0.09	0.13	0.64
Dividends declared per Common Share ($)	**0.2600**	0.2600	0.2375	0.2375

($ millions, except per Common Share amounts)	Q4-18	Q3-18	Q2-18	Q1-18
Revenue	95.3	44.1	59.9	109.8
Normalized net income (loss)[2]	20.0	(1.0)	3.8	19.0
Net income after taxes	20.8	0.5	3.7	20.2
Net income after taxes per Common Share - basic and diluted ($)[3]	0.69	0.02	0.12	0.67
Dividends declared per Common Share ($)[4]	0.1744	—	—	—

(1) Amounts may not add due to rounding.

(2) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

(3) For comparative purposes, the Common Shares issued under the IPO including the Over-Allotment Option, have been assumed to be outstanding as of January 1, 2018.

(4) ACI declares and pays a quarterly dividend on its Common Shares. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of ACI. Dividends declared per Common Share in the fourth quarter of 2018 are for the period from October 25, 2018 to December 31, 2018

Quarter-over-quarter financial results are impacted by seasonality, weather, planned and unplanned outages, and timing and recognition of regulatory decisions.

Revenue for the Utilities segment is generally the highest in the first and fourth quarters of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March. The equity investment in the Northwest Hydro Facilities is impacted by seasonal precipitation and snowpack melt, which create periods of high river flow typically during May through October of any given year. In the third quarter of 2018, a one-time revenue of approximately $1.8 million was recorded in relation to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods.

Net income after taxes is affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, impairment, gains and losses on foreign exchange contracts, and gains or losses on the sale of assets. For these reasons, net income may not necessarily reflect the same trends as revenue. Net income after taxes during the periods noted was impacted by:

- higher interest expense during the fourth quarter of 2018 as a result of incremental borrowing to capitalize ACI as a standalone business;
- lower income tax expense during the fourth quarter of 2018 as a result of the transition of ACI to a standalone entity;
- lower interest expense throughout 2019 as a result of lower average interest rates on the MTNs and external credit facilities compared to the debt outstanding to AltaGas during 2018, partially offset by a higher average debt balance outstanding;
- an income tax recovery recognized in the second quarter of 2019 as a result of the one-time deferred income tax recovery related to the reduction in the Alberta statutory tax rate in June 2019 and the decrease in current income tax expense due to accelerated tax deductions related to PP&E; and
- after tax transaction costs of approximately $1.8 million incurred in the fourth quarter of 2019 in respect of the Arrangement.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

The Company's primary sources of liquidity are cash flow from operations and debt additions. The Company's cash requirements include funding for capital expenditures and working capital, servicing and repaying long-term debt, and dividend payments. The Company's sources and uses of cash are further discussed below:

		Year Ended December 31
($ millions)	**2019**	2018
Cash from operations	**76.6**	89.9
Cash used in investing activities	**(70.4)**	(76.2)
Cash used in financing activities	**(7.8)**	(11.9)
Increase (decrease) in cash and cash equivalents	**(1.6)**	1.8

Cash from operations

During the year ended December 31, 2019, cash from operations decreased by $13.3 million as compared to the same period in 2018 primarily due to the absence of a special distribution of $20.3 million received from the equity investment in the Northwest Hydro Facilities in 2018 as a result of the change in control of the entities indirectly holding the Northwest Hydro Facilities**,** partially offset by higher cash earnings.

Investing activities

During the year ended December 31, 2019, cash used in investing activities decreased by $5.8 million as compared to the same period in 2018 primarily due to timing of cash payments for capital expenditures.

See also the "*Invested Capital*" section of this MD&A.

Financing activities

During the year ended December 31, 2019, cash used in financing activities decreased by $4.1 million as compared to the same period in 2018 primarily due to the absence of various transactions that occurred in 2018 to capitalize ACI as a standalone entity, partially offset by an increase in dividends paid.

Working Capital

($ millions except current ratio)		**December 31, 2019**		December 31, 2018
Current assets	**$**	**71.7**	$	74.7
Current liabilities		**109.3**		91.5
Working capital deficiency	**$**	**(37.6)**	$	(16.8)
Working capital ratio		**0.66**		0.82

The variation in the working capital ratio was primarily due to an increase in short-term debt, the recognition of a mark-to-market liability on foreign exchange contracts instead of an asset, and the recognition of a current liability relating to leases, partially offset by a decrease in regulatory liabilities and an increase in regulatory assets. ACI's working capital will fluctuate in the normal course of business and the working capital deficiency will be funded using cash flow from operations and available credit facilities as required.

Capital Resources

The Company's objective for managing capital is to maintain its investment grade credit rating, ensure adequate liquidity, maximize the profitability of its existing assets and grow its business through prudent capital investments which ultimately add to the utilities' rate base, and enhance returns to investors. The Company's capital resources is comprised of short-term and long-term debt (including the current portion).

The use of debt or equity funding is based on ACI's capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

($ millions, except where noted)		**December 31, 2019**	December 31, 2018
Short-term debt	**$**	**12.1**	5.8
Current portion of long-term debt(1)		**14.8**	1.0
Long-term debt(2)		**642.8**	638.8
Total debt		**669.7**	645.6
Less: cash and cash equivalents		**(0.2)**	(1.8)
Net debt(3)	**$**	**669.5**	643.8
Shareholders' equity		**620.6**	608.6
Total capitalization	**$**	**1,290.1**	1,252.4
Net debt-to-total capitalization(3) (%)		**51.9**	51.4

(1) Net of debt issuance costs of $0.2 million as of December 31, 2019 (December 31, 2018 - $nil).

(2) Net of debt issuance costs of $3.1 million as of December 31, 2019 (December 31, 2018 - $2.5 million).

(3) Non-GAAP financial measure; see discussion in the *"Non-GAAP Financial Measures"* section of this MD&A.

On April 3, 2019, ACI completed the issuance of $250 million of MTNs with a coupon rate of 3.15 percent (3.151 percent yield to maturity) and a maturity date of April 6, 2026. The net proceeds were used to repay: (i) as to approximately $210 million, a portion of the Term Loan; and (ii) as to the remainder, amounts outstanding under the Revolving Credit Facility.

On December 5, 2018, ACI issued $300 million of MTNs with a coupon rate of 4.26 percent (4.269 percent yield to maturity) and maturity date of December 5, 2028. The net proceeds were used to pay down a portion of the Purchase Price Long-Term Note.

As at December 31, 2019, ACI's total debt primarily consisted of outstanding MTNs of $550.0 million (2018 - $300 million), PNG debentures of $25.0 million (2018 - $26.0 million), unsecured syndicated term loan of $14.0 million (2018 - $250 million), and

$83.5 million drawn under other bank credit facilities (2018 - $72.8 million). In addition, ACI had $7.7 million of letters of credit issued (2018 - $7.7 million).

As at December 31, 2019, ACI's total market capitalization was approximately $1.0 billion based on 30,000,000 Common Shares outstanding and a closing trading price on December 31, 2019 of $33.37 per Common Share.

ACI's earnings interest coverage for the rolling 12 months ended December 31, 2019 was 2.7 times (12 months ended December 31, 2018 – 2.7 times).

Credit Facilities

The Company funds its long and short term borrowing requirements with credit facilities as follows:

($ millions)	**Borrowing capacity**	**Drawn at December 31, 2019**	Drawn at December 31, 2018
Syndicated revolving credit facility[(1)]	$ **200.0**	$ **46.4**	$ 48.0
Syndicated term loan[(2)]	**14.0**	**14.0**	250.0
Operating credit facility[(3)]	**35.0**	**4.7**	4.0
PNG committed credit facility[(4)]	**25.0**	**25.0**	19.0
PNG operating credit facility[(5)]	**25.0**	**15.1**	9.5
	$ **299.0**	$ **105.2**	$ 330.5

(1) On October 25, 2018, the Company entered into definitive credit agreements establishing the $200 million unsecured syndicated revolving credit facility that matures October 25, 2022. On February 13, 2020, the Company extended the maturity date to December 31, 2023. Borrowing options under this facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings against this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. There are no mandatory repayments prior to maturity under this facility. The facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(2) On October 25, 2018, the Company entered into definitive credit agreements establishing the $250 million unsecured syndicated term loan that matures October 25, 2020. The term loan was fully drawn on October 25, 2018 and as at December 31, 2019, $14.0 million remains on the term loan. Borrowing options under this term loan include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings against this term loan bear fees and interest at rates relevant to the nature of the draw made and the Company credit rating. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. This term loan has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(3) On October 25, 2018, the Company entered into a definitive credit agreement with a Canadian chartered bank establishing the $35 million revolving operating credit facility. Borrowings under this facility are due on demand. Borrowing options under this facility include overdraft, letters of credit, Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on this credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating. This facility is used to fund overdraft amounts and to issue letters of credit. As at December 31, 2019 a total of $3.8 million (2018 - $4.0 million) in letters of credit were issued and are outstanding. This facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has complied with all financial covenants each quarter since the establishment of this facility.

(4) On May 4, 2018, PNG completed the financing of $55 million of revolving five-year credit facilities, $30 million of which was with AltaGas and $25 million of which is with a Canadian chartered bank. The facilities mature on May 4, 2023. The $30 million AltaGas intercompany term loan was acquired by the Company in connection with the Acquisition. The $25 million external facility will be used to support PNG's capital spending program. Borrowings under the external facility are available by way of bankers' acceptances bearing interest at the three-month bankers' acceptance rate plus a spread and subject to stand-by fees. Interest and stand-by costs are due monthly. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. The facilities have covenants customary for these types of facilities, which must be met at each quarter end. PNG has been in compliance with all financial covenants each quarter since the establishment of these facilities.

(5) On May 4, 2018, PNG completed the financing of the $25 million PNG operating credit facility with a Canadian chartered bank. This facility matures on May 4, 2021. The operating line is available for working capital purposes through cash draws in the form of prime-rate advances or bankers' acceptances and the issuance of letters of credit and is collateralized by a charge on PNG's accounts receivable and inventories. As at December 31, 2019, $3.9 million (2018 - $3.7 million) of letters of credit were issued and outstanding under this facility.

The following table summarizes the Company's primary financial covenants as defined by the credit facility agreements:

Ratios	**Debt covenant requirements**	**As at December 31, 2019**
Bank debt-to-capitalization[(1)(2)]	not greater than 65 percent	52%
Bank EBITDA-to-interest expense[(1)(2)]	not less than 2.5x	4.1x

(1) Calculated in accordance with the Company's credit facility agreements, which are available on SEDAR at *www.sedar.com*.

(2) Estimated, subject to final adjustments.

Base Shelf Prospectus

On November 14, 2018, a $1.0 billion base shelf prospectus was filed. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25 month period that the base shelf prospectus remains effective. As at December 31, 2019, approximately $450 million was available under the base shelf prospectus.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities.

On December 5, 2019, DBRS Limited ("DBRS") confirmed ACI's Issuer Rating and Unsecured Medium Term Notes rating of BBB(high) with a Stable trend.

Long-term obligations which are rated in the "BBB" category by DBRS are in the fourth highest category and are considered to be of adequate credit quality, with acceptable capacity for the payment of financial obligations. Entities in the "BBB" category may be considered to be vulnerable to future events, but the capacity for the payment of financial obligations is considered acceptable. DBRS uses "High" or "Low" designations to indicate the relative standing of the securities being rated within a particular rating category.

The credit ratings assigned by DBRS are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There can be no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by DBRS at any time in the future, if in their judgment, circumstances so warrant. The credit ratings on a security may not reflect the potential impact of all risks related to the value of the security.

Except as set forth above, DBRS have not announced that it is reviewing or intends to revise or withdraw the ratings on ACI.

ACI provides an annual fee to DBRS for credit rating services. ACI has paid DBRS its respective fees in connection with the provision of the above ratings. In addition to the aforementioned fees, ACI has made payments in respect of certain other services provided to the Company by DBRS.

CONTRACTUAL OBLIGATIONS

December 31, 2019					Payments Due by Period
($ millions)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Accounts payable and accrued liabilities	$ 62.1	$ 62.1	$ —	$ —	$ —
Short-term debt(1)	12.1	12.1	—	—	—
Long-term debt(1)	660.9	15.0	2.0	72.4	571.5
Operating and finance leases(2)	13.9	1.7	2.6	1.4	8.2
Purchase obligations(3)	340.6	40.5	60.4	38.9	200.8
Pension plan and retiree benefits(4)	6.8	6.8	—	—	—
Service agreement(5)	25.7	7.0	6.0	2.6	10.1
Total contractual obligations	$ 1,122.1	$ 145.2	$ 71.0	$ 115.3	$ 790.6

(1) Excludes interest payments and deferred financing costs.

(2) Operating and finance leases include lease arrangements for office spaces, land, and office and other equipment.

(3) The Company entered into contracts to purchase natural gas and natural gas transportation services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2020 to 2040, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

(4) Assumes only required payments will be made into the pension plans in 2020. Contributions are made in accordance with independent actuarial valuations.

(5) In 2007, the Company entered into a service and maintenance agreement with Enercon GmbH for the Bear Mountain wind turbines. The Company has an obligation to pay Enercon GmbH a minimum of $4.0 million over the next two years. In 2019, the Company entered into a long-term agreement for software implementation, hosting and maintenance. The Company is obligated to pay approximately US$17.0 million over the 12 year term of the contract.

CAPITAL EXPENDITURES

($ millions)	Three Months Ended December 31, 2019 Renewable Energy	Utilities	Corporate	Total	Three Months Ended December 31, 2018 Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E[1]	**$ —**	**$ 27.4**	**$ 0.1**	**$ 27.5**	$ —	$ 24.7	$ —	$ 24.7
Intangible assets	**—**	**4.4**	**0.1**	**4.5**	—	1.2	—	1.2
Capital expenditures	**—**	**31.8**	**0.2**	**32.0**	—	25.9	—	25.9
Disposals:								
PP&E	**—**	**(0.1)**	**—**	**(0.1)**	—	—	—	—
Net capital expenditures	**$ —**	**$ 31.7**	**$ 0.2**	**$ 31.9**	$ —	$ 25.9	$ —	$ 25.9

(1) Excludes $0.7 million of capitalized operating, maintenance and administrative expenses which have been deferred in regulatory assets as allowed by the CRP for the three months ended December 31, 2019 (2018 - $0.4 million).

($ millions)	Year Ended December 31, 2019 Renewable Energy	Utilities	Corporate	Total	Year Ended December 31, 2018 Renewable Energy	Utilities	Corporate	Total
Capital expenditures:								
PP&E[1]	**$ —**	**$ 69.6**	**$ 0.3**	**$ 69.9**	$ —	$ 68.5	$ —	$ 68.5
Intangible assets	**—**	**6.8**	**0.1**	**6.9**	—	3.2	—	3.2
Capital expenditures	**—**	**76.4**	**0.4**	**76.8**	—	71.7	—	71.7
Disposals:								
PP&E	**—**	**(0.2)**	**—**	**(0.2)**	—	(0.3)	—	(0.3)
Net capital expenditures	**$ —**	**$ 76.2**	**$ 0.4**	**$ 76.6**	$ —	$ 71.4	$ —	$ 71.4

(1) Excludes $2.5 million of capitalized operating, maintenance and administrative expenses which have been deferred in regulatory assets as allowed by the CRP for the year ended December 31, 2019 (2018 - $2.4 million).

Capital expenditures for the three months and year ended December 31, 2019 was $32.0 million and $76.8 million, respectively, the majority of which relates to system betterment, replacement of transmission and distribution lines and new business installations. In addition, AUI incurred approximately $9.2 million for the Etzikom Lateral Project in 2019. Including the costs incurred in 2018, the total cost of Etzikom Lateral Project was approximately $9.7 million.

INDEMNIFICATIONS AND CONTINGENCIES

Indemnifications

Under the terms of its gas transportation and supply agreements with certain customers, PNG has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of its property, plant and equipment, or in connection with the presence of gas deemed to be in its possession and control. PNG has $50 million of insurance coverage for third party liability with a $0.1 million deductible. PNG has also provided environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by PNG with applicable environmental laws.

Contingencies

The Company is subject to various legal claims and actions arising in the normal course of business. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Company does not believe that the resolution of such claims and actions will have a material impact on the Company's results of operations.

RISK MANAGEMENT

ACI is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. The Board of Directors provides oversight of the Company's risk management activities.

Risks Associated with Financial Instruments

The Company is exposed to various financial risks in the normal course of operations such as market risks resulting from currency exchange rates and interest rates as well as credit risk and liquidity risk.

Foreign Exchange Risk

A vast majority of HGL's natural gas supply costs are denominated in U.S. dollars. Although all natural gas procurement costs, including any realized foreign exchange gains or losses are passed through to its customers, the Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in gas costs for customers as a result of changes in foreign exchange rates. Details concerning the Company's outstanding foreign exchange forward contracts at December 31, 2019 and December 31, 2018 are provided in note 16 to the Consolidated Financial Statements.

Interest Rate Risk

The Company is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Company manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. In addition, the Company's strategy is to optimize financing plans to maintain credit ratings to minimize interest costs. The Company proactively monitors and manages its debt maturity profile and debt covenants and maintains financial flexibility through access to multiple credit facilities.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract. The Company's maximum credit exposure consists primarily of the carrying value of accounts receivable and the fair value of derivative financial assets. The Company's utilities business generally has a large and diversified customer base, which minimizes the concentration of credit risk. To minimize credit risk, the utilities business will request for a security deposit which is eligible for refund after an observable period of compliance with payment terms. A credit report may also be requested. For the Company's Renewable Energy segment, all power generated are sold under the EPA with BC Hydro, an investment grade counterparty.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations as they come due and to support business operations and capital program. The Company's objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required. The Company's strategy is to maintain and comply with debt covenants to minimize financing costs. The Company's primary sources of liquidity and capital resources are cash generated from operations, borrowings under credit facilities, and long-term debt. The Company actively monitors current and future credit metrics including the impact of any forecasted planned capital expenditures in excess of cash from operations. The Company also maintains a base shelf prospectus which allows the Company ready access to the Canadian debt and capital market, subject to market conditions.

Risks Associated with ACI's Operations

The following table is a summary of the Company's principal risks related to its operations that could materially affect its business, results of operations, financial condition or cash flows. Further information on the Company's risk factors can be found in the Annual Information Form. ACI manages its exposure to risks associated with operating its business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks
Regulatory and Stakeholder	
The Company is subject to uncertainties faced by regulated companies such as the approval by the applicable regulators of rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. A failure to obtain rates that recover the costs of providing service or provide a reasonable opportunity to earn an expected ROE and capital structure as applied for may adversely affect the business carried on by the Company and may have a material adverse effect on the Company's results of operations and financial position. The acquisition, ownership and operation of natural gas businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies and indigenous peoples. If there is a delay in obtaining any required regulatory approval or if the Company fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of natural gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Company's results of operations and financial position. The market for renewable power is heavily influenced by federal, provincial and local government regulations and policies in respect of tariffs, market structure and penalties. The Company's inability to predict, influence or respond appropriately to changes in law or regulatory frameworks could adversely impact the Company's results of operations.	• Skilled regulatory department retained • Regulatory personnel monitor new or changed laws or regulations • Proactive regulatory and stakeholder relations group • Maintain constructive and transparent relationships with stakeholders and regulators • Use of expert third parties when needed
Weather impact on the utilities	
The natural gas distribution business is highly seasonal with the majority of natural gas demand occurring during the winter heating season. The applicable regulators set rates which assume normal weather conditions.	• Anticipated volumes are determined based on the 20-year rolling average for weather at AUI and HGL • PNG has a weather normalization account for residential and small commercial customers
Demand for natural gas	
Natural gas demand is impacted by a number of factors, including the weather, economic conditions, the number of customers, the customer mix, the availability and price of natural gas and alternative forms of energy and energy efficiency measures taken by customers. The commodity cost of natural gas has traditionally been volatile. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk to levels of demand for natural gas, as other energy sources can become more cost-competitive.	• Stakeholder engagement • CRP in place at HGL to mitigate fuel switching
Volume of power generated	
Financial performance of the Company's renewable energy assets is dependent upon the availability of their input resources. The strength and consistency of the wind resource at the Bear Mountain Wind Park may impact the volume of power generated. A reduced amount of wind at the location of the Bear Mountain Wind Park over an extended period may reduce the production from the facility. This could also include shifts in weather or climate patterns, seasonal precipitation, and the timing and rate of snow pack melting and runoff which may impact the water flow to the Northwest Hydro Facilities and impact the volume of power generated. In addition, a material reduction in the water flow to Northwest Hydro Facilities would limit the ability to produce and market electricity from these facilities.	• EPAs for the Bear Mountain Wind Park and Northwest Hydro Facilities are in place for all power generated to be purchased. • Diversification of fuel source (wind and hydro) • Active management of maintenance schedule at Bear Mountain Wind Park to ensure the facility is available to produce when wind conditions are favourable.

Risks	Strategies and Organizational Capability to Mitigate Risks
Operational	
The natural gas distribution and renewable energy infrastructure is subject to physical risks such as fires, floods, explosions, leaks, sabotage, terrorism, natural disasters and equipment malfunction, many of which are beyond the control of the Company. Any of these hazards can interrupt operations, impact the Company's reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, and cause environmental damage that may include polluting water, land or air. Unplanned outages or prolonged downtime for maintenance and repair typically increase operation and maintenance expenses and reduce revenues.	• Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Ongoing infrastructure replacement programs within natural gas distribution system • Purchase property and business interruption insurance • Emergency response plan communicated and in place
Environment and safety	
The ownership and operation of the Company's regulated utilities and renewable power assets carries an inherent risk of liability related to worker health and safety and the environment. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licences, permits and other approvals will remain material to the Company's businesses. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licences, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures.	• Strong safety and environmental management systems • Continuous process improvement strategy employed • Focus on mitigating the impact of the climate change regulations • Zero tolerance safety policies for staff and contractors and reviews of past safety practices for contractors • Purchase and maintain general liability and business interruption insurance • Pipeline and asset integrity programs are in place
Cybersecurity	
Security breaches of the Company's information technology infrastructure, including, without limitation, cyber-attacks, cyber-terrorism, malware/ransomware or other failures of the Company's information technology infrastructure could result in operational outages, delays, damage to assets, the environment or to the Company's reputation, diminished customer confidence, lost profits, lost data (including confidential information), increased regulation and other adverse outcomes, including, without limitation, material legal claims and liability or fines or penalties under applicable laws and adversely affect its business operations and financial results.	• Continuously updated perimeter and internal security • Ongoing cybersecurity awareness training to staff and corporate communications • Improvements based on third-party vulnerability and cybersecurity tests • Security-focused solution and system design • Corporate threat detection and incident response protocols • Cybersecurity insurance coverage
Labour relations	
The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain skilled workforces and the inability to do so could have a material adverse effect on the Company. The Company employs members of labour unions that have entered into collective bargaining agreements with the Company. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have a material adverse effect on the Company's results of operations and financial position.	• Maintain access to strong labour markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions • Maintain succession plans for key positions • Maintain competitive compensation programs
Litigation	
In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company.	• Proactive management of lawsuits and other claims • Continuous monitoring of defense and settlement costs of lawsuits and claims • Use of expert third parties when needed • Strong in-house legal department

RELATED PARTY TRANSACTIONS

Concurrent with the completion of the Acquisition on October 18, 2018, the Company entered into a Transition Services Agreement with AltaGas pursuant to which AltaGas provides certain general administrative and corporate services required by the Company, which include: accounting, tax, finance, legal and regulatory, payroll, corporate human resources and pension management, environmental, health and safety administration, procurement, enterprise resource planning and information technology. AltaGas provides the services on a cost recovery basis only. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances, and is extendable by mutual agreement of the parties.

The following transactions with ACI's affiliates and AltaGas and its affiliates are measured at the exchange amount and have been recorded on the Consolidated Statements of Income:

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Revenue [1]	**$ 0.8**	$ 0.5	**$ 2.4**	$ 3.9
Unrealized gain (loss) on foreign exchange contracts with AltaGas	**$ —**	$ 0.4	**$ (0.9)**	$ 1.2
Cost of sales [2]	**$ (23.9)**	$ (33.4)	**$ (100.8)**	$ (93.2)
Operating and administrative expenses [3]	**$ (0.3)**	$ (1.3)	**$ (1.9)**	$ (8.6)
Interest expense [4]	**$ —**	$ (4.7)	**$ —**	$ (22.1)

(1) *In the normal course of business, the Company provided gas sales and transportation services to related parties.*

(2) *In the normal course of business, the Company purchased natural gas from a related party.*

(3) *Operating and administrative expenses include the allocation of corporate costs for the year ended December 31, 2018 from AltaGas, fees paid to AltaGas for transition services, and administrative costs recovered from affiliates.*

(4) *Interest expense on debt due to related parties.*

SHARE INFORMATION

	As at March 4, 2020
Issued and outstanding	
Common shares	30,000,000
Issued	
Share options	534,766
Share options exercisable	50,095

In addition, as at March 4, 2020, there were an aggregate of 210,647 restricted share units and performance share units outstanding, which, upon vesting, are paid in cash or, at the option of the Company, in Common Shares issued from treasury or purchased from the market.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. The Company's significant accounting policies are described in note 3 to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

Significant estimates and judgments made by management in the preparation of the Consolidated Financial Statements are outlined below:

Regulatory Assets and Liabilities

AUI, HGL and PNG engage in the delivery and sale of natural gas and are regulated by the following regulatory agencies: AUC, NSUARB and BCUC, respectively.

The regulatory agencies exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the regulators, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate-setting process.

Asset Impairment

The Company reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. The determination of fair value requires management to make assumptions about future cash inflows and outflows over the life of an asset. Any changes to assumptions used for the future cash flow could result in revisions to the evaluation of the recoverability of the long-lived assets or intangible assets and the recognition of an impairment loss in the Consolidated Financial Statements.

The Company also tests goodwill for impairment annually at December 31 or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Company has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the fair value of each reporting unit is compared to its carrying value. The fair value of each reporting unit is determined using either the income approach or the market approach. If the carrying value of the reporting unit exceeds the fair value, an impairment loss would be recorded in the Consolidated Statement of Income. The determination of the fair value of the reporting units used in a quantitative impairment test of goodwill requires judgment and involves significant assumptions. Under the income approach, the fair value of the reporting unit is estimated based on future cash flows as well as appropriate discount rates. Under the market approach, the estimation of fair value involves analysis regarding comparable transactions and premiums paid. The Company assessed goodwill for impairment as at December 31, 2019 and determined that no write-down was required.

Revenue Recognition

Revenue includes natural gas sales that are recorded on the basis of estimates of customer usage from the last meter reading date to the end of the reporting period.

Asset Retirement Obligations

The Company records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation. See note 12 to the Consolidated Financial Statements for the assumptions used in calculating the asset retirement obligations.

Income Taxes

The Company is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada. The determination of the Company's provision for income taxes requires the application of these complex rules.

Deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. A valuation allowance is recorded against deferred tax assets where all or a portion of that asset is not expected to be realized. The amount of the deferred tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of tax authorities, or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See note 15 to the Consolidated Financial Statements.

Pension Plans and Post-Retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Critical assumptions include the expected long-term rate-of-return on plan assets, the discount rate applied to pension plan obligations, and the expected rate of compensation increase. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Note 19 to the Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Depreciation and Amortization

Depreciation and amortization of property, plant, and equipment and intangible assets are based on management's judgment of the estimated useful life of the assets. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. For regulated entities, amortization rates are generally prescribed by the applicable regulatory authority. There are a number of uncertainties inherent in estimating the remaining useful life of certain assets and changes in assumptions could result in material adjustments to the amount of amortization that the Company recognizes from period to period.

Loss Contingencies

The Company is subject to various legal claims and actions arising in the normal course of business. Liabilities for loss contingencies are determined on a case-by-case basis and are accrued for when it is probable that a liability has been incurred and the amount can be reasonably estimated. Significant judgement is required to determine the probability of having incurred the liability and the estimated amount. Estimates are reviewed regularly and updated as new information is received. As at December 31, 2019, no provisions on loss contingencies have been recorded by the Company. However, due to the inherent uncertainty of the litigation process, the resolution of any particular contingencies could have a material adverse effect on the Company's results of operations or financial position.

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by management. Where bid or ask prices in an active market are not available, management's judgment on valuation inputs is necessary to determine fair value. The Company uses derivative instruments to manage fluctuations in foreign exchange rates. The Company estimates forward prices based on published sources. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Leases – Lessee

The Company recognizes a right of use asset and lease liability at the lease commencement date. In determining the lease liability, judgement is required, including (a) identifying whether a contract includes a lease, (b) determining the term of the lease and whether it is reasonably certain that lease extension or termination options will be exercised; and (c) the discount rate. See note 8 to the Consolidated Financial Statements for the assumptions used in calculating the lease liability.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2019, the Company adopted the following FASB issued Accounting Standards Updates ("ASU"):

- ASU No. 2016-02 "Leases" and all related amendments (collectively "ASC 842"). ACI has applied ASC 842 using the modified retrospective approach as of the effective date of the new standard. Comparative information has not been restated and continues to be reported under the previous lease guidance ASC 840. The Company has applied the package of transition practical expedients which permitted the Company to not reassess (a) whether any expired or existing contracts contain leases, (b) lease classifications for any expired or existing leases, and (c) initial direct costs for any existing leases. In addition, the Company applied the transition practical expedient that permitted the Company to grandfather its accounting policy for land easements that existed as of, or expired, before January 1, 2019. On adoption of ASC 842, all operating leases were recognized on the balance sheet with an increase to other long-term assets of approximately $5.3 million and an increase to lease liabilities of approximately $4.2 million (net of the current portion which was recorded under other current liabilities of approximately $1.1 million). The lease liabilities were measured using the present value of the remaining minimum lease payments for existing operating leases discounted using the Company's incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019, adjusted for any prepaid or accrued lease payments. The adoption of ASC 842 did not impact lessor accounting, the consolidated statement of income, or the consolidated statement of cash flow. Please also refer to note 8 in the Consolidated Financial Statements for further details.

- ASU No. 2018-07 "Compensation – Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting". The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees, with the objective of making the measurement consistent with employee share based payment awards. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2018-15 "Intangibles-Goodwill and Other – Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract". The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, however, the Company has chosen to early adopt this ASU. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements; and

- ASU No. 2019-08 "Compensation – Stock Compensation (Topic 718) and Revenue from Contracts with Customers (Topic 606). The amendments in this ASU align the measurement of share based sales incentives in accordance with ASC 718 to measure and classify using a fair-value based measure to calculate the incentive on grant data and reflect the result as a reduction of revenue in accordance with ASC 606. The adoption of this ASU did not have a material impact on the Company's Consolidated Financial Statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. Early adoption is permitted. The Company is currently completing its assessment of the impact of these ASUs on its Consolidated Financial Statements.

In August 2018, FASB issued ASU No. 2018-13 "Fair Value Measurement – Disclosure Framework: Changes to the Disclosure Requirements for Fair Value Measurement". The amendments in this ASU modify the disclosure requirements on fair value measurements. The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

In August 2018, FASB issued ASU No. 2018-14 "Compensation – Retirement Benefits-Defined Benefit Plans – General: Disclosure Framework – Changes to the Disclosure Requirements for the Defined Benefit Plans". The amendments in this ASU modify the disclosure requirements on defined benefit pension and other postretirement plans. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

In October 2018, FASB issued ASU 2018-17 "Consolidation – Targeted Improvements to Related Party Guidance for Variable Interest Entities ("VIE")". The amendments in this ASU provide that indirect interest held through related parties under common control will be considered on a proportional basis when determining whether fees paid to decision makers and service providers are variable interests. Under the new guidance, fewer decision-making fees will be considered variable interests in a VIE because the other interests held will be less significant using the proportionate method rather than when considered in their entirety. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. All entities are required to apply the amendments in this ASU retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

In November 2018, FASB issued ASU 2018-18 "Collaborative Arrangements – Clarifying the Interaction between Topic 808 and Topic 606". The amendments in this ASU clarifies that certain transactions between collaborative partners should be accounted for as revenue under ASC 606 when the collaborative partner is a customer, provides guidance specifying that a distinct good or service is the unit of account for evaluating whether a transaction is with a customer, and precludes a company from presenting transactions with a collaborative partner that are not in the scope of ASC 606 together with revenue from contracts with customers. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

In April 2019, FASB issued ASU No. 2019-04 "Topic 815 – Derivatives and Hedges and Topic 825 – Financial Instruments." The amendments in this ASU clarify aspects of ASU 2017-12 regarding partial-term fair value hedges and fair value basis adjustments. In addition, this ASU, amends ASU 2016-01 to clarify that the measurement alternative in ASC 321-10 for equity securities without readily determinable fair value represents a nonrecurring fair value measurement under ASC 820. The amendments to ASU 2017-12 and ASU 2016-01 are effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal years. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

In December 2019, FASB issued ASU No. 2019-12 "Income Taxes (Topic 740) Simplifying the Accounting for Income Taxes". The amendments in this ASU removes certain exceptions and provides some simplifications in accounting for income taxes. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020. The adoption of this ASU is not expected to have a material impact on the Company's Consolidated Financial Statements.

OFF-BALANCE SHEET ARRANGEMENTS

In October 2014, HGL entered into a throughput service contract with Enbridge Inc. (formerly Spectra Energy Corp.) for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems. The contract will commence upon completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas issued two guarantees with an aggregate maximum liability of approximately US$91.7 million, guaranteeing HGL's payment obligations under the throughput service contract with Enbridge Inc. Effective October 25, 2018, the two guarantees issued by AltaGas were cancelled and reissued by ACI.

On October 22, 2018, the Company issued a guarantee with a maximum liability of $0.3 million related to the right of way for permanent access and power line access at the Bear Mountain Wind Park.

The Company, through HGL has agreements in place with Union Gas Limited ("UGL") to deliver natural gas. In October 25, 2018, the Company issued a guarantee with a maximum liability of $0.3 million guaranteeing UGL's reasonable costs incurred to enforce obligations created under those agreements.

The Company, through HGL has agreements in place with Maritimes & Northeast Pipeline Limited Partnership ("M&NP") to store or transport natural gas. On December 1, 2019, The Company issued a guarantee with a maximum liability of $3.0 million guaranteeing M&NP's reasonable costs incurred to enforce obligations created under those agreements.

DISCLOSURE CONTROLS AND PROCEDURES ("DC&P") AND INTERNAL CONTROL OVER FINANCIAL REPORTING ("ICFR")

ACI is required to comply with National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*. The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation. ACI's management, including its Chief Executive Officer and Chief Financial Officer certified that they have designed or caused it to be designed under their supervision, DC&P and ICFR to provide reasonable assurance that information required to be disclosed by the Company in its annual flings, interim filings and other reports filed or submitted by it under securities legislation is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements are prepared in accordance with U.S. GAAP.

There were no material weaknesses in the design of DC&P and ICFR as at December 31, 2019 and no changes in ICFR during the interim period from October 1, 2019 to December 31, 2019 that have materially affected, or are reasonably likely to materially effect, the Company's ICFR.

The ICFR has been designed based on the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, ACI has evaluated the effectiveness of the Company's DC&P and ICFR as at December 31, 2019 and concluded that as at December 31, 2019, the Company's DC&P and ICFR were effective.

It should be noted that a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, including instances of fraud, if any, have been detected. The design of any system of controls is also based in part on certain assumptions about the likelihood of future events, and there can be no assurances that any design will succeed in achieving its stated goals under all potential conditions.

SELECTED ANNUAL FINANCIAL INFORMATION

		Year Ended December 31	
($ millions, except where noted)	**2019**	2018	2017
Revenue	**326.3**	309.1	309.2
Net income after taxes	**42.1**	45.3	41.7
Net income after taxes per Common Share - Basic ($ per Common Share)(1)	**1.40**	1.51	1.39
Net income after taxes per Common Share - Diluted ($ per Common Share)(1)	**1.40**	1.51	1.39
Total assets	**1,582.3**	1,515.5	1,611.8
Total long-term financial liabilities(3)	**645.9**	641.3	411.2
Weighted average number of Common Shares outstanding (millions)(1)	**30.0**	30.0	30.0
Dividends declared per Common Share ($ per share)(2)	**0.9950**	0.1744	—

(1) For comparative purposes, the Common Shares issued under the IPO including the Over-Allotment option, have been assumed to be outstanding as of the beginning of each period, including the periods prior to the Acquisition.

(2) Dividends declared per Common Share after the completion of IPO for the period from October 25, 2018 to December 31, 2018.

(3) Excludes deferred financing costs.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures used by the Company that do not have a standardized meaning prescribed by U.S. GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with U.S. GAAP. The non-GAAP measures and their reconciliation to U.S. GAAP financial measures are shown below. These non-GAAP measures provide additional information that Management believes is meaningful in describing the Company's operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to normalized EBITDA, normalized net income, normalized funds from operations, net debt and net debt to total capitalization throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized EBITDA	**$ 40.1**	$ 34.2	**$ 113.5**	$ 105.2
Add (deduct):				
Foreign exchange loss	**(0.1)**	—	**—**	(0.1)
Unrealized gain (loss) on foreign exchange contracts	**(0.7)**	0.8	**(2.2)**	1.7
Accretion expense	**—**	—	**(0.1)**	(0.1)
Part VI.1 revenue from AltaGas	**—**	—	**—**	1.8
Depreciation and amortization expense	**(9.6)**	(6.9)	**(31.7)**	(28.9)
Accretion and depreciation and amortization expense from equity investment	**(1.0)**	(0.9)	**(3.8)**	(3.6)
Transaction costs	**(2.3)**	—	**(2.3)**	—
Operating income	**$ 26.4**	$ 27.2	**$ 73.4**	$ 76.0

Normalized EBITDA is a measure of the Company's operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using operating income adjusted for depreciation and amortization expense, accretion expenses, foreign exchange gain (loss), unrealized gain (loss) on foreign exchange contracts, and other typically non-recurring items. Normalized EBITDA is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets and the capital structure.

Normalized EBITDA as presented should not be viewed as an alternative to operating income or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Net Income

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized net income	**$ 18.6**	$ 20.0	**$ 45.3**	$ 41.8
Add (deduct) after-tax:				
Unrealized gain (loss) on foreign exchange contracts	**(0.7)**	0.8	**(2.2)**	1.7
Part VI.1 revenue from AltaGas	**—**	—	**—**	1.8
Income tax recovery related to decrease in Alberta statutory tax rate	**—**	—	**0.8**	—
Transaction costs	**(1.8)**	—	**(1.8)**	—
Net income after taxes	**$ 16.1**	$ 20.8	**$ 42.1**	$ 45.3

Normalized net income represents net income after taxes adjusted for after tax impact of unrealized gain (loss) on foreign exchange contracts and other typically non-recurring items. This measure is presented in order to enhance the comparability of results, as it reflects the underlying performance of the Company.

Normalized net income as presented should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Funds from Operations

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized funds from operations	**$ 34.7**	$ 28.6	**$ 79.9**	$ 88.1
Add (deduct):				
Part VI.1 revenue from AltaGas	**—**	—	**—**	1.8
Changes in operating assets and liabilities	**(15.2)**	(2.2)	**(1.0)**	—
Transaction costs	**(2.3)**	—	**(2.3)**	—
Cash from operations	**$ 17.2**	$ 26.4	**$ 76.6**	$ 89.9

Normalized funds from operations is used to assist Management and investors in analyzing the liquidity of the Company without regard to changes in operating assets and liabilities in the period as well as other non-operating related income and expenses. Management uses this measure to understand the ability to generate funds for use in investing and financing activities.

Normalized funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with U.S. GAAP as an indicator of liquidity.

Net Debt and Net Debt to Total Capitalization

Net debt and net debt to total capitalization are used by the Company to monitor its capital structure and financing requirements. It is also used as a measure of the Company's overall financial strength. Net debt is defined as short-term debt, plus current and long-term portions of long-term debt, less cash and cash equivalents. Total capitalization is defined as net debt plus shareholders' equity. Additional information regarding these non-GAAP measures can be found under the *Capital Resources* section of this MD&A.

DEFINITIONS

CPI means Consumer Price Index
GJ means gigajoule
GW means gigawatt
GWh means gigawatt hour
MW means megawatt
MWh means megawatt hour
PJ means petajoule; one million gigajoules
US$ means United States dollar

ABOUT ACI

ACI is a Canadian company with natural gas distribution utilities and renewable power generation assets. ACI serves approximately 130,000 customers, delivering low carbon energy, safely and reliably. For more information visit: www.altagascanada.ca.

Management's Responsibility for Financial Reporting

The Consolidated Financial Statements and Management's Discussion and Analysis ("MD&A") of AltaGas Canada Inc. (the "Company") are the responsibility of Management and have been approved by the Board of Directors of the Company. The Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP") and include amounts that are based on Management's best estimates and judgments.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting for the Company. Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and accurate, and that the Company's assets are safeguarded and that transactions are properly executed in accordance with Management's authorization. Management undertakes communication to employees of policies that govern ethical business conduct.

The Consolidated Financial Statements and MD&A are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of independent non-management directors.

The Audit Committee meets with Management regularly and meets independently with internal and external auditors and as a group to review any significant accounting, internal controls and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing Management's performance in carrying out its financial reporting responsibilities and reviewing the Consolidated Financial Statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without obtaining prior Management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed Ernst & Young LLP as independent external auditors to express an opinion as to whether the Consolidated Financial Statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with U.S. GAAP. The report of Ernst & Young LLP outlines the scope of its examination and its opinion on the Consolidated Financial Statements.

(signed) "Jared Green"

JARED GREEN
President and
Chief Executive Officer
AltaGas Canada Inc.

(signed) "Shaun Toivanen"

SHAUN TOIVANEN
Executive Vice President and
Chief Financial Officer
AltaGas Canada Inc.

March 4, 2020

Independent Auditor's Report

To the Shareholders of AltaGas Canada Inc.

Opinion

We have audited the consolidated financial statements of AltaGas Canada Inc. and its subsidiaries (the Group), which comprise the consolidated balance sheets as at December 31, 2019 and 2018, and the consolidated statements of income and comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at December 31, 2019 and 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles (US GAAP).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, 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.

In preparing the consolidated financial statements, management is responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Group's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Gord M. Graham.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Alberta
March 4, 2020

Consolidated Balance Sheets

As at *($ millions)*	**December 31, 2019**	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	**$ 0.2**	$ 1.8
Accounts receivable, net of allowances *(note 16)*	**64.6**	64.4
Inventory *(note 4)*	**1.4**	1.4
Regulatory assets *(note 7)*	**1.6**	0.6
Foreign exchange contracts asset *(note 16)*	**—**	1.4
Prepaid expenses and other current assets	**3.9**	5.1
	71.7	74.7
Property, plant and equipment *(note 5)*	**1,003.8**	968.6
Intangible assets *(note 6)*	**21.9**	17.5
Goodwill	**119.1**	119.1
Regulatory assets *(note 7)*	**235.0**	215.8
Other long-term assets *(notes 8 and 19)*	**12.4**	0.9
Investments accounted for by the equity method *(note 9)*	**118.4**	118.9
	$ 1,582.3	$ 1,515.5
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 16)*	**$ 62.1**	$ 64.9
Short-term debt *(notes 10 and 16)*	**12.1**	5.8
Current portion of long-term debt *(notes 8 and 11)*	**14.8**	1.0
Customer deposits	**10.1**	10.9
Regulatory liabilities *(note 7)*	**7.1**	8.9
Foreign exchange contracts liability *(note 16)*	**0.8**	—
Other current liabilities *(note 8)*	**2.3**	—
	109.3	91.5
Long-term debt *(notes 8, 11 and 16)*	**642.8**	638.8
Asset retirement obligations *(note 12)*	**3.1**	1.8
Deferred income taxes *(note 15)*	**136.3**	122.6
Regulatory liabilities *(note 7)*	**26.6**	22.1
Lease liabilities *(note 8)*	**7.0**	—
Future employee obligations *(note 19)*	**36.6**	30.1
	$ 961.7	$ 906.9

As at *($ millions)*	**December 31, 2019**	December 31, 2018
Shareholders' equity		
Common shares, no par value, unlimited shares authorized; December 31, 2019 and 2018 - 30 million shares issued and outstanding *(note 17)*	**321.0**	321.0
Contributed surplus	**100.5**	100.0
Retained earnings	**200.2**	188.0
Accumulated other comprehensive loss *(notes 13 and 19)*	**(1.1)**	(0.4)
	620.6	608.6
	$ 1,582.3	$ 1,515.5

Commitments and contingencies *(note 20)*
Subsequent events *(note 24)*

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Canada Inc.

(signed) "David W. Cornhill"

DAVID W. CORNHILL
Director

(signed) "William J. Demcoe"

WILLIAM J. DEMCOE
Director

Consolidated Statements of Income

($ millions except per share amounts)		2019		Year ended December 31 2018
REVENUE *(note 14)*	**$**	**326.3**	$	309.1
EXPENSES				
Cost of sales, exclusive of items shown separately		**125.8**		117.3
Operating and administrative		**100.4**		92.5
Accretion *(note 12)*		**0.1**		0.1
Depreciation and amortization *(notes 5 and 6)*		**31.7**		28.9
		258.0		238.8
Income from equity investments *(note 9)*		**7.4**		4.2
Unrealized gain (loss) on foreign exchange contracts *(note 16)*		**(2.2)**		1.7
Other loss		**(0.1)**		(0.1)
Foreign exchange loss		**—**		(0.1)
Operating income		**73.4**		76.0
Interest expense				
Short-term debt		**(0.5)**		(3.3)
Long-term debt		**(26.4)**		(25.2)
Income before income taxes		**46.5**		47.5
Income tax expense (recovery) *(note 15)*				
Current		**2.2**		3.5
Deferred		**2.2**		(1.3)
Net income after taxes	**$**	**42.1**	$	45.3
Net income per common share *(note 18)*				
Basic	**$**	**1.40**	$	1.51
Diluted	**$**	**1.40**	$	1.51

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Comprehensive Income

($ millions)		2019		Year ended December 31 2018
Net income after taxes	**$**	**42.1**	$	45.3
Other comprehensive income (loss) (OCI), net of taxes				
Actuarial gain (loss) on pension and post-retirement benefit plans *(notes 13 and 19)*		**(0.7)**		0.2
Other comprehensive income (loss), net of taxes		**(0.7)**		0.2
Comprehensive income, net of taxes	**$**	**41.4**	$	45.5

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Equity

($ millions)		2019		Year ended December 31 2018
Common shares *(note 17)*				
Balance, beginning of year	$	**321.0**	$	—
Shares issued to AltaGas Ltd. in connection with the Acquisition		**—**		58.4
Shares issued on public offering, net of issuance costs (after tax)		**—**		228.1
Shares issued pursuant to over-allotment option, net of issuance costs (after tax)		**—**		34.5
Balance, end of year	$	**321.0**	$	321.0
Net parental investment *(note 21)*				
Balance, beginning of year	$	**—**	$	804.7
Net income after taxes		**—**		28.8
Distributions to AltaGas Ltd. prior to the Acquisition		**—**		(114.7)
Transactions in connection with the Acquisition		**—**		(383.7)
Recapitalization by AltaGas Ltd.		**—**		(335.1)
Balance, end of year	$	**—**	$	—
Contributed surplus				
Balance, beginning of year	$	**100.0**	$	—
Share option expense		**0.5**		100.0
Balance, end of year	$	**100.5**	$	100.0
Retained earnings				
Balance, beginning of year	$	**188.0**	$	—
Recapitalization by AltaGas Ltd.		**—**		176.7
Net income after taxes		**42.1**		16.5
Common share dividends		**(29.9)**		(5.2)
Balance, end of year	$	**200.2**	$	188.0
Accumulated other comprehensive loss *(note 13)*				
Balance, beginning of year	$	**(0.4)**	$	(0.6)
Other comprehensive income (loss)		**(0.7)**		0.2
Balance, end of year	$	**(1.1)**	$	(0.4)
Total shareholders' equity	$	**620.6**	$	608.6

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

($ millions)		2019		Year ended December 31 2018
Cash from operations				
Net income after taxes	**$**	**42.1**	$	45.3
Items not involving cash:				
Depreciation and amortization expense *(notes 5 and 6)*		**31.7**		28.9
Accretion expense *(note 12)*		**0.1**		0.1
Deferred income tax expense (recovery) *(note 15)*		**2.2**		(1.3)
Income from equity investments *(note 9)*		**(7.4)**		(4.2)
Unrealized loss (gain) on foreign exchange contracts *(note 16)*		**2.2**		(1.7)
Other		**(1.3)**		(2.0)
Distributions from equity investment		**8.0**		24.8
Changes in operating assets and liabilities *(note 22)*		**(1.0)**		—
	$	**76.6**	$	89.9
Investing activities				
Acquisition of property, plant and equipment		**(63.7)**		(73.2)
Acquisition of intangible assets		**(6.9)**		(3.3)
Proceeds from disposition of assets, net of transaction costs		**0.2**		0.3
	$	**(70.4)**	$	(76.2)
Financing activities				
Net issuance of advances due to related parties		**—**		134.2
Net issuance (repayment) of short-term debt		**6.3**		(3.3)
Net issuance (repayment) of bankers' acceptances		**(231.0)**		316.3
Issuance of long-term debt, net of debt issuance costs		**248.1**		297.7
Repayment of long-term debt due to related parties		**—**		(28.4)
Repayment of notes issued to AltaGas Ltd.		**—**		(858.9)
Repayment of long-term debt		**(1.0)**		(8.0)
Issuance of common shares, net of share issuance costs		**(0.3)**		258.4
Distributions to AltaGas Ltd. prior to the Acquisition		**—**		(114.7)
Common share dividends		**(29.9)**		(5.2)
	$	**(7.8)**	$	(11.9)
Change in cash and cash equivalents		**(1.6)**		1.8
Cash and cash equivalents, beginning of year		**1.8**		—
Cash and cash equivalents, end of year	**$**	**0.2**	$	1.8

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars, unless otherwise indicated.)

1. OVERVIEW OF THE COMPANY

AltaGas Canada Inc. (the "Company") was incorporated under the *Canada Business Corporations Act* ("CBCA") on October 27, 2011 as AltaGas Utility Holdings (Pacific) Inc., a wholly owned subsidiary of AltaGas Ltd. ("AltaGas"). On September 5, 2018, the Company amended its articles to, among other things, facilitate it becoming a public company, change its name to AltaGas Canada Inc., amend its authorized capital and consolidate its outstanding common shares on the basis of one post-consolidation common share for every 28 pre-consolidation common shares. Prior to the acquisition of assets from AltaGas (the "Acquisition"), as further described below, the Company owned rate-regulated natural gas distribution and transmission utility assets in British Columbia through its subsidiaries, Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)"). Subsequent to the Acquisition, the Company owns rate-regulated natural gas distribution and transmission utility businesses in Alberta, British Columbia, Nova Scotia and the Northwest Territories, wind power assets located near Dawson Creek, British Columbia and an approximately 10 percent indirect interest hydroelectric power generation assets in northwest British Columbia. The Company is a reporting issuer listed on the Toronto Stock Exchange.

Pending Acquisition of ACI

On October 21, 2019, ACI announced it had entered into a definitive arrangement agreement (the "Arrangement Agreement") pursuant to which the Public Sector Pension Investment Board and the Alberta Teachers' Retirement Fund Board (together, the "Consortium") will indirectly acquire through PSPIB Cycle Investments Inc. (the "Purchaser"), all of the issued and outstanding common shares of ACI for $33.50 in cash per common share pursuant to a plan of arrangement under the CBCA (the "Arrangement"). The Board of Directors, after receiving the unanimous recommendation of an independent committee of the Board of Directors formed to review and consider various strategic and financial options available to ACI and in consultation with its financial and legal advisors, unanimously determined that the Arrangement is in the best interests of ACI and fair to the holders of common shares and therefore unanimously recommended that holders of common shares vote in favour of the Arrangement.

On December 19, 2019, the holders of the common shares voted to approve the Arrangement and on December 20, 2019, ACI received the Final Order from the Court of Queen's Bench of Alberta approving the transaction.

ACI has received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not intend to challenge the proposed acquisition, as well as approval of the transaction from the Alberta Utilities Commission ("AUC").

Closing of the Arrangement remains subject to approval of the transaction from the British Columbia Utilities Commission ("BCUC") and the satisfaction or waiver of other customary closing conditions. The Arrangement is expected to close in the first half of 2020.

The Company is expected to incur certain customary closing costs but the closing of the Arrangement is not expected to have a material impact on the financial condition, financial performance and future cash flows of the Company.

Acquisition of Assets from AltaGas (the "Acquisition")

On October 18, 2018, pursuant to the Purchase and Sale Agreement, the Company acquired the following assets from AltaGas for approximately $889.1 million (the "Acquired Assets"), through the acquisition of (a) all of the issued and outstanding common shares of AltaGas Utility Group Inc. ("AUGI"); (b) all of the issued and outstanding common shares of Bear Mountain Wind Power Corporation ("BMWPC"); (c) AltaGas' 99.99 percent partnership interest in Bear Mountain Wind Limited Partnership ("BMWLP") as a limited partner; (d) AltaGas' 99.99 percent partnership interest in AltaGas Canadian Energy Holdings Limited Partnership as a limited partner; (e) all of the issued and outstanding common shares of AltaGas Canadian Energy Holdings Ltd.; and (f) 10 common shares in the capital of Northwest Hydro GP Inc. (“Coast GP”), the general partner of Northwest Hydro Limited Partnership (“Coast LP”):

- Rate-regulated natural gas distribution utility assets in Alberta and Nova Scotia owned by AUGI via its operating subsidiaries, AltaGas Utilities Inc. (“AUI”) and Heritage Gas Limited (“HGL”);
- Minority interests in entities (Inuvik Gas and Ikhil Joint Venture) providing natural gas to the Town of Inuvik, Northwest Territories;
- Fully contracted 102 MW Bear Mountain Wind Park located near Dawson Creek, British Columbia (the “Bear Mountain Wind Park”) owned by BMWLP and BMWPC; and
- Approximately 10 percent indirect equity interest in the capital of Coast LP and Coast GP which indirectly own three fully contracted 303 MW run of river hydroelectric power generation assets in northwest British Columbia (the “Northwest Hydro Facilities”) by way of the CMH Group.

Pursuant to the Purchase and Sale Agreement, the Company also acquired on October 18, 2018, the indebtedness that AUGI and PNG owed to AltaGas and certain of its subsidiaries in the aggregate amount of approximately $481.6 million (the “Acquired Indebtedness”)

The Company satisfied the purchase price of $889.1 million for the Acquired Assets and Acquired Indebtedness by issuing to AltaGas the following:

- 5,912,857 common shares;
- An unsecured promissory note dated October 18, 2018 bearing interest at 4.5 percent per annum in the principal amount of approximately $316.3 million (the “Purchase Price Short-Term Note”) which was to be repaid upon closing of the initial public offering by the Company of its common shares completed on October 25, 2018 (the “IPO”);
- An unsecured promissory note dated October 18, 2018 bearing interest at 3.3 percent per annum in the principal amount of $35.9 million (adjustable to approximately $34.0 million in the event the over-allotment option is exercised in full) (the “Over-Allotment Note”) which was to be repaid no later than 30 days after closing of the IPO; and
- An unsecured promissory note dated October 18, 2018 bearing interest at 4.5 percent per annum in the principal amount of $351.2 million (the “Purchase Price Long-Term Note”) with a term of 30 months, the interest to be increased by 0.25 percent on the 18 and 24 month anniversaries of the issuance date.

The Purchase Price Short-Term Note, the Over-Allotment Note, and the Purchase Price Long-Term Note have been fully repaid as at December 31, 2018.

Immediately prior to the Acquisition:

- The Company paid an eligible dividend of $31.0 million to AltaGas;
- BMWLP distributed cash of $64.6 million to AltaGas; and
- AUGI repaid indebtedness of $28.4 million to AltaGas.

Initial Public Offering of Common Shares

On October 25, 2018, the Company completed its IPO, issuing 16,500,000 common shares at a price of $14.50 per common share for gross proceeds of $239.3 million.

In connection with the IPO, the Company granted to the underwriters of the IPO an over-allotment option (the “Over-Allotment Option”), exercisable at the underwriters’ discretion at any time, in whole or in part, until 30 days following the closing of the IPO, to purchase at $14.50 per common share up to an additional 2,475,000 common shares (representing 15 percent of the common shares offered under the IPO) to cover over-allotments, if any, and for market stabilization purposes. On November 21, 2018, the Over-Allotment Option was exercised in full for additional gross proceeds of $35.9 million.

Upon closing of the IPO and the exercise of the Over-Allotment Option, 30,000,000 common shares were issued and outstanding, of which AltaGas owned approximately 36.8 percent. The Company ceased to be a wholly-owned subsidiary of AltaGas upon completion of the IPO on October 25, 2018.

The net proceeds of the IPO were $223.7 million after deducting the underwriters' fee of $12.6 million and approximately $3.0 million in other expenses. The net proceeds from the exercise of the Over-Allotment Option were $34.0 million after deducting the underwriters' fee of $1.8 million and other expenses of $0.1 million. In accordance with the Purchase and Sale Agreement, the Company used the net proceeds of the IPO and including the proceeds from the exercise of the Over-Allotment Option, to:

- Repay in full a note issued by the Company to AltaGas bearing interest at 5.0 percent per annum in the principal amount of $157.4 million issued in connection with a return on capital on the Company's common shares immediately prior to the Acquisition;
- Repay a portion of the Purchase Price Short-Term Note with the remaining portion of the Purchase Price Short-Term Note being repaid with the proceeds of the syndicated term loan; and
- Repay in full the Over-Allotment Note. Per the terms of the Over-Allotment Note, if the Over-Allotment Option was exercised, the principal amount would be reduced by the amount of the underwriters' fee and other expenses of approximately $1.9 million. On November 21, 2018, the Company repaid the Over-Allotment Note in full.

2. BASIS OF PRESENTATION

Basis of Preparation

These consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP").

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" ("NI 52-107"), U.S. GAAP reporting is permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that the Company is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, the Company sought and obtained exemptive relief from the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2024, the date upon which the Company ceases to have activities subject to rate regulation, or the effective date prescribed for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

As all of the businesses acquired from AltaGas were transferred in contemplation of and immediately prior to the IPO, the acquisitions are considered a common control transaction with the consolidated financial statements being prepared on a continuity of interest basis. The financial information prior to October 18, 2018 included in these consolidated financial statements has been derived from the accounting records of AltaGas using the historical results of operations and historical basis of the assets and liabilities acquired from AltaGas as though the Company and the acquired businesses had been one consolidated entity for all periods presented.

Since the Company operated as part of AltaGas and was not a stand-alone entity prior to October 18, 2018, the historical consolidated financial statements include allocations of certain AltaGas revenue, expenses, assets and liabilities.

Transactions with AltaGas and its affiliates have been identified as related party transactions. It is possible that the terms of the transactions with AltaGas and its affiliates are not the same as those that would result from transactions among unrelated parties. In the opinion of the Company's management, all adjustments have been reflected that are necessary for a fair presentation in the consolidated financial statements. Also, the Company's management believes that expenses related to shared assets and liabilities have been allocated by AltaGas to the Company on a reasonable basis, as described in note 21, and have been applied consistently for each period presented.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its direct and indirect subsidiaries, including, without limitation: AUGI, BMWLP, AltaGas Canadian Energy Holdings Ltd., PNG, AUI, and HGL. The consolidated financial statements also include investments in Inuvik Gas Ltd. and Coast LP, which are accounted for by the equity method. Intercompany transactions and balances are eliminated. Investments in unconsolidated companies that the Company has significant influence over, but not control, are accounted for using the equity method. In addition, the Company uses the equity method of accounting for investments in limited partnership interests in which it has more than a minor interest or influence over the partnership's operating and financial policies.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition

Renewable Energy segment

The majority of the revenues are earned through power purchase agreements whereby the Company is the lessor in these operating lease arrangements. Variable lease payments are recorded as revenue in the period in which the changes in facts and circumstances on which the variable lease payments are based on occur, such as when actual electricity is generated and delivered.

Utilities segment

Customers are billed monthly based on regular meter readings. Customer billings are based on two components: (i) a fixed service fee; and (ii) a variable fee based on usage. Revenue is recognized over time when the gas has been delivered or as the service has been performed. As meter readings occur on a cycle basis, the Company recognizes accrued revenue for any services rendered to its customers but not billed at month-end. Although the majority of these contracts have a term of one-month, certain contracts have terms of one year or longer. For these long-term contracts, there is generally a contract demand specified in the contract whereby the customer has to pay regardless of whether or not gas has been delivered. These contracts generally do not contain any make up rights and revenue is recognized monthly as service is performed.

Rate-Regulated Operations

AUI, PNG and HGL, (collectively “the Utilities”) engage in the delivery and sale of natural gas and are regulated by the AUC, the BCUC, and the Nova Scotia Utility and Review Board (“NSUARB”), respectively.

The AUC, BCUC, and NSUARB exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC, BCUC, and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate setting process. See note 7 for a description of the principal financial statements effects of rate regulation.

Cash and cash equivalents

Cash and cash equivalents include cash on deposit with banks and interest-bearing short term investments with a maturity of three months or less when purchased. Cash and cash equivalents are stated at cost, which approximates market value.

Accounts Receivable

Receivables are recorded net of the allowance for doubtful accounts in the Consolidated Balance Sheet. The Company regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, and natural gas, which are valued at the lower of cost or net realizable value. Cost of inventory is determined using a weighted average cost formula.

Property, Plant, and Equipment ("PP&E") and Depreciation

PP&E are carried at cost. The Company depreciates the cost of PP&E, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of rate regulated utilities assets, where depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

Interest costs are capitalized on major additions to PP&E until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on the prior quarter actual borrowing long-term interest rate.

Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction ("AFUDC"). AFUDC is the amount that a rate regulated enterprise is allowed to recover for its cost of financing assets under construction. Capitalized overhead, administrative expenses and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers through depreciation expense, as allowed by the regulators.

Certain additions to PP&E are made with the assistance of contributions in aid of construction, which are offset against the corresponding asset balances and amortized at the same rate as the corresponding asset.

The range of useful lives for the Company's PP&E is as follows:

Renewable Energy assets	30 years
Utilities assets	3 – 75 years
Corporate assets	2 – 3 years

As required by the respective regulatory authorities, net additions to utility assets at HGL and PNG are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI are depreciated commencing in the year in which the assets are brought into active service.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in the Consolidated Statement of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statement of Income.

Leases - Lessee

Under Accounting Standards Codification ("ASC") Topic 842, Leases, an arrangement contains a lease when such arrangement conveys the right to control the use of an identified asset. ACI recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which consists of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, less any lease incentives received and any initial direct costs incurred by the lessee. The lease liability is initially measured at the present value of the lease payments that are not yet paid at the commencement date, discounted using the interest rate implicit in the lease or if that cannot be readily determined, ACI's incremental borrowing rate. Lease payments include: fixed payments (including in substance fixed payments), variable lease payments that are based on an index or a rate, the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, payments for penalties for terminating the lease if the lease term reflects the lessee exercising that option, and amounts probable of being payable by the lessee under residual value guarantees. The Company has elected the practical expedient to not separate lease and non-lease components for its office and equipment leases. Subsequent measurement of the right-of-use asset and lease liability depend on whether the lease is classified as an operating lease or financing lease. Lease payments for leases with a term of twelve months or less are expensed on a straight-line basis over the lease term.

Intangible Assets

Intangible assets which have a finite life are recorded at cost and are amortized on a straight-line basis over their term or estimated useful life. The range of useful lives for intangible assets with a finite life is as follows:

Software	3 - 10 years
Land rights	5 - 75 years
Franchises and consents	9 - 25 years

Impairment of Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value and an impairment loss is recognized.

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Company has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the fair value of each reporting unit is compared to its carrying value. The fair value of each reporting unit is determined using either the income approach or the market approach. If the carrying value of the reporting unit exceeds the fair value, an impairment loss would be recorded in the Consolidated Statement of Income.

Development Costs

The Company expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria continue to be met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period of benefit, beginning at the commencement of commercial operations.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which the Company has the ability to exercise significant influence, but does not have a controlling interest. In addition, the Company uses the equity method of accounting for investments in limited partnership interests in which it has more than a minor interest or influence over the partnership's operating and financial policies. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Company will capitalize interest costs associated with its investment during such period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statement of Income.

Financial Instruments

Financial instruments are initially recorded at fair value unless they qualify for, and are designated under a normal purchase and normal sale ("NPNS") exemption. Subsequent measurement of the financial instruments is based on their classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Company's business needs and the Company has the ability, and intent, to deliver or take delivery of the underlying item. The Company continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading financial assets and liabilities consist of foreign exchange forward contracts. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income under “unrealized gain and loss from foreign exchange contracts”. Held-to-maturity, loans and receivables, and other financial liabilities are recognized at amortized cost using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in earnings.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheet. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “Interest expense” on the Consolidated Statement of Income.

Asset Retirement Obligations

The Company recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

Certain utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to their indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations.

Foreign Currency Translation

These consolidated financial statements are presented in Canadian dollars. Monetary assets and liabilities denominated in a foreign currency are converted to the functional currency (Canadian dollars) using the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statement of Income. Non-monetary assets and liabilities are converted at the historical exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

Pension Plans and Post-Retirement Benefits

The Company maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Company to the defined contribution plans are expensed in the period in which the contribution occurs. The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated based on service and management’s best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Pension expense for the defined benefit and post-retirement benefit plans includes the cost of pension benefits earned during the year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments, the amortization of prior service costs, and the amortization of cumulative unrecognized net actuarial gains and losses in excess of 10 percent of the greater of the accrued benefit obligation or the fair value of plan assets. Amortizations are calculated on a straight-line basis over the expected average remaining service life of active employees. The expected average remaining service period of the active members covered by the defined benefit pension plans and the post-retirement benefit plans is 15.0 years and 14.7 years, respectively.

The Company recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheet. Unrecognized actuarial gains and losses and past service costs and credits that arise during the period are recognized in OCI.

For certain regulated Utilities, the Company expects to recover pension expense in future rates and therefore records actuarial gains and losses as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees or the benefit period for employees, or a specific recovery period as approved by the respective regulator.

Stock-Based Compensation

Share options granted are recorded using fair value. Compensation expense is measured at the date of the grant using the Black-Scholes-Merton model and is recognized over the vesting period of the options. Consideration received by the Company on exercise of the share options is credited to shareholders' equity.

The Company has a medium-term incentive plan ("MTIP") for directors, officers and employees which includes two types of awards: restricted share units ("RSUs") and performance share units ("PSUs"). Both RSUs and PSUs are valued based on the dividends declared during the vesting period and the weighted average share price of the Company's common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RSUs and PSUs are paid in cash or, at the election of the Company, its equivalent in common shares issued from treasury or purchased from the market. The PSUs are also subject to a performance multiplier. Compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the RSUs or PSUs is recognized in the period the change occurs.

In addition, the Company has a deferred share unit plan ("DSUP") for directors, officers and employees as an additional form of long-term variable compensation incentive. Although the DSUP is available to directors, officers and employees, the Company currently only intends to grant deferred share units ("DSUs") under the DSUP as a form of director compensation. The DSUs granted are fully vested upon grant and immediately credited to a participant's account. Payment of the value of DSUs granted occurs on or following the participant's termination date, and payment is not subject to satisfaction of any requirements as to any minimum period of membership or employment or other conditions. Such payment may be satisfied in cash or in common shares purchased from the market. DSUs are accounted for at fair value. Compensation expense is determined based on the fair value of the DSUs on the date of the grant and fluctuations in fair value are recognized in the period the change occurs.

Earnings per Share

Basic earnings per share is computed by dividing net income after tax by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed giving effect to the potential dilution that would occur if stock options were exercised. The method the Company uses to determine the dilutive impact of stock options assumes that any proceeds from the exercise of in-the-money stock options would be used to purchase common shares at the average market price during the period.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized.

The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Investment tax credits, if any, are deferred and amortized over the estimated service lives of the related assets.

Interest and penalties assessed by taxing authorities on any underpayment of income tax are accrued and classified as a component of interest expense in the Consolidated Statement of Income.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from, or paid to, customers in the future.

Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Any such accruals are adjusted thereafter as additional information becomes available or circumstances change.

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: revenue recognition, depreciation and amortization rates, determination of the classification, term and discount rate for leases, fair value of asset retirement obligations, fair value of property, plant and equipment and goodwill for impairment assessments, fair value of financial instruments, provisions for income taxes, assumptions used to measure employee future benefits, provisions for contingencies, and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which the Company operates, which often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2019, the Company adopted the following Financial Accounting Standards Board ("FASB") issued Accounting Standards Updates ("ASU"):

- ASU No. 2016-02 "Leases" and all related amendments (collectively "ASC 842"). ACI has applied ASC 842 using the modified retrospective approach as of the effective date of the new standard. Comparative information has not been restated and continues to be reported under the previous lease guidance ASC 840. The Company has applied the package of transition practical expedients which permitted the Company to not reassess (a) whether any expired or existing contracts contain leases, (b) lease classifications for any expired or existing leases, and (c) initial direct costs for any existing leases. In addition, the Company applied the transition practical expedient that permitted the Company to grandfather its accounting policy for land easements that existed as of, or expired, before January 1, 2019. On adoption of ASC 842, all operating leases were recognized on the balance sheet with an increase to other long-term assets of approximately $5.3 million and an increase to lease liabilities of approximately $4.2 million (net of the current portion which was recorded under other current liabilities of approximately $1.1 million). The lease liabilities were measured using the present value of the remaining minimum lease payments for existing operating leases discounted using the Company's incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019, adjusted for any prepaid or accrued lease payments. The adoption of ASC 842 did not impact lessor accounting, the consolidated statement of income, or the consolidated statement of cash flow. Please also refer to note 8 for further details.

- ASU No. 2018-07 "Compensation – Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting". The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees, with the objective of making the measurement consistent with employee share based payment awards. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2018-15 "Intangibles-Goodwill and Other – Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract". The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, however, the Company has chosen to early adopt this ASU. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements; and

- ASU No. 2019-08 "Compensation – Stock Compensation (Topic 718) and Revenue from Contracts with Customers (Topic 606)". The amendments in this ASU align the measurement of share based sales incentives in accordance with ASC 718 to measure and classify using a fair-value based measure to calculate the incentive on grant data and reflect the result as a reduction of revenue in accordance with ASC 606. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments". The amendments in this ASU replace the current "incurred loss" impairment methodology with an "expected loss" model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates" which deferred the effective date of ASU No. 2016-13 to January 1, 2023. Early adoption is permitted. The Company is currently completing its assessment of the impact of these ASUs on its consolidated financial statements.

In August 2018, FASB issued ASU No. 2018-13 "Fair Value Measurement – Disclosure Framework: Changes to the Disclosure Requirements for Fair Value Measurement". The amendments in this ASU modify the disclosure requirements on fair value measurements. The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's consolidated financial statements.

In August 2018, FASB issued ASU No. 2018-14 "Compensation – Retirement Benefits-Defined Benefit Plans – General: Disclosure Framework – Changes to the Disclosure Requirements for the Defined Benefit Plans". The amendments in this ASU modify the disclosure requirements on defined benefit pension and other postretirement plans. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company's consolidated financial statements.

In October 2018, FASB issued ASU 2018-17 “Consolidation – Targeted Improvements to Related Party Guidance for Variable Interest Entities (“VIE”)”. The amendments in this ASU provide that indirect interest held through related parties under common control will be considered on a proportional basis when determining whether fees paid to decision makers and service providers are variable interests. Under the new guidance, fewer decision-making fees will be considered variable interests in a VIE because the other interests held will be less significant using the proportionate method rather than when considered in their entirety. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. All entities are required to apply the amendments in this ASU retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company’s consolidated financial statements.

In November 2018, FASB issued ASU 2018-18 “Collaborative Arrangements – Clarifying the Interaction between Topic 808 and Topic 606”. The amendments in this ASU clarifies that certain transactions between collaborative partners should be accounted for as revenue under ASC 606 when the collaborative partner is a customer, provides guidance specifying that a distinct good or service is the unit of account for evaluating whether a transaction is with a customer, and precludes a company from presenting transactions with a collaborative partner that are not in the scope of ASC 606 together with revenue from contracts with customers. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Company’s consolidated financial statements.

In April 2019, FASB issued ASU No. 2019-04 “Topic 815 – Derivatives and Hedges and Topic 825 – Financial Instruments.” The amendments in this ASU clarify aspects of ASU 2017-12 regarding partial-term fair value hedges and fair value basis adjustments. In addition, this ASU, amends ASU 2016-01 to clarify that the measurement alternative in ASC 321-10 for equity securities without readily determinable fair value represents a nonrecurring fair value measurement under ASC 820. The amendments to ASU 2017-12 and ASU 2016-01 are effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal years. The adoption of this ASU is not expected to have a material impact on the Company’s consolidated financial statements.

In December 2019, FASB issued ASU No. 2019-12 “Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes”. The amendments in this ASU removes certain exceptions and provides some simplifications in accounting for income taxes. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020. The adoption of this ASU is not expected to have a material impact on the Company’s consolidated financial statements.

4. INVENTORY

As at	**December 31, 2019**	December 31, 2018
Natural gas	**$ 0.7**	$ 0.8
Other inventory	**0.7**	0.6
	$ 1.4	$ 1.4

5. PROPERTY, PLANT AND EQUIPMENT

As at	**December 31, 2019**			December 31, 2018		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Renewable Energy	**$ 212.5**	**$ (71.2)**	**$ 141.3**	$ 211.0	$ (63.9)	$ 147.1
Utilities	**1,003.6**	**(141.4)**	**862.2**	941.3	(119.8)	821.5
Corporate	**0.3**	**—**	**0.3**	—	—	—
	$ 1,216.4	**$ (212.6)**	**$ 1,003.8**	$ 1,152.3	$ (183.7)	$ 968.6

Interest capitalized on long-term capital construction projects for the year ended December 31, 2019 was $0.1 million (2018 - $nil).

Contributions in aid of construction of $3.5 million (2018 - $4.3 million) were recorded as a reduction of cost during the year.

Depreciation expense related to property, plant and equipment for the year ended December 31, 2019 was $27.6 million (2018 - $25.7 million). As at December 31, 2019, the Company had approximately $20.2 million (December 31, 2018 - $13.3 million) of capital projects under construction that were not yet subject to amortization. In addition, as at December 31, 2019, $2.6 million of land costs (December 31, 2018 - $9.2 million) were not subject to amortization.

6. INTANGIBLE ASSETS

As at	**December 31, 2019**			December 31, 2018		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Software	**$ 26.2**	**$ (12.4)**	**$ 13.8**	$ 29.0	$ (19.7)	$ 9.3
Land rights	**9.4**	**(2.5)**	**6.9**	9.2	(2.3)	6.9
Franchises and consents	**3.6**	**(2.4)**	**1.2**	3.6	(2.3)	1.3
	$ 39.2	**$ (17.3)**	**$ 21.9**	$ 41.8	$ (24.3)	$ 17.5

Amortization expense related to intangible assets for the year ended December 31, 2019 was $3.0 million (2018 - $2.6 million).

As at December 31, 2019, the Company excluded $1.9 million (December 31, 2018 - $1.9 million) of assets with an indefinite life from the asset base subject to amortization.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization as well as assets with indefinite life, for the years ended December 31:

2020	$ 3.4
2021	$ 3.6
2022	$ 2.8
2023	$ 2.1
2024	$ 0.8
Thereafter	$ 7.3

7. REGULATORY ASSETS AND LIABILITIES

The Company accounts for certain transactions in accordance with ASC 980, Regulated Operations. The Company refers to this accounting guidance for regulated entities as “regulatory accounting". Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheet when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statement of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statement of Income in future periods when the amounts are reflected in customer rates. Management’s assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the AUC, BCUC and NSUARB.

If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting for all or part of its utility operations, regulatory assets and liabilities related to those portions ceasing to meet the criteria would be de-recognized from the Consolidated Balance Sheet and included in the Consolidated Statement of Income for the period in which discontinuance of regulatory accounting occurs. Factors that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the Company’s ability to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Company’s review of these criteria currently supports continued application of regulatory accounting for the Utilities.

The table below summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets as at December 31, 2019 and 2018 and the remaining period over which the Company expects to realize the assets or settle the liabilities:

As at		**December 31, 2019**		December 31, 2018	Recovery Period
Regulatory assets - current					
Deferred cost of gas	**$**	**1.0**	$	0.1	Less than one year
Deferred property taxes		**0.6**		0.5	Less than one year
	$	**1.6**	$	0.6	
Regulatory assets - non-current					
Deferred regulatory costs and rate stabilization adjustment	**$**	**4.5**	$	2.5	Various
Future recovery of pension and other retirement benefits [(a)]		**33.6**		30.2	Various
Deferred depreciation and amortization [(b)]		**22.0**		22.6	Various
Deferred future income taxes [(c)]		**115.6**		103.9	Various
Deferred customer retention program amortization [(d)]		**36.2**		26.2	Various
Revenue deficiency account [(e)]		**21.2**		28.0	Various
Other		**1.9**		2.4	Various
	$	**235.0**	$	215.8	
Regulatory liabilities - current					
Deferred cost of gas	**$**	**6.7**	$	7.3	Less than one year
Deferred regulatory costs		**—**		1.4	Less than one year
Other		**0.4**		0.2	Less than one year
	$	**7.1**	$	8.9	
Regulatory liabilities - non-current					
Option fees deferral [(f)]	**$**	**4.6**	$	4.5	Various
Future removal and site restoration costs [(g)]		**22.0**		17.5	Various
Other		**—**		0.1	Various
	$	**26.6**	$	22.1	

(a) Certain utilities have recovered pension costs related to regulated operations in rates, and as such the Company has recorded a regulatory asset for the pension funding deficiency. Depending on the method utilized by the utility the recovery period can be either the expected service life of the employees or the benefit period for employees or a specific recovery period as approved by the respective regulator.

(b) Pursuant to the NSUARB decisions in 2009 and 2011, HGL was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the fiscal periods from 2009 to 2013. The NSUARB, in its decision dated November 24, 2011, directed amortization to be phased in over a four year period at the following rates: 2014 at 25 percent of the authorized rates; 2015 at 50 percent of the authorized rates; 2016 at 75 percent of the authorized rates; and 2017 at 100 percent of the authorized rates. As a result of this order, HGL recognized a regulatory asset equal to the amortization that would have otherwise been included in rates.

(c) Remaining amortization period varies depending on the timing of underlying transactions.

(d) In 2016, the NSUARB approved HGL's Customer Retention Program application to decrease distribution rates for commercial customers with consumption between 500 and 4,999 gigajoule per year, suspend depreciation and to increase the capitalization rate for operating, maintenance and administrative expenses effective March 22, 2016.

(e) HGL has an approval from the NSUARB to use a revenue deficiency account ("RDA") until it is fully recovered, subject to a maximum of $50 million, imposed in 2010, which may be increased subject to approval by the NSUARB. The RDA is the cumulative difference between the revenue requirements and the actual amounts billed to customers.

(f) Pursuant to BCUC approved negotiated settlement agreement.

(g) This amount and timing of draw down is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.

8. LEASES

The Company's leases include: land, buildings, and office and field equipment.

As at	**December 31, 2019**	January 1, 2019
Weighted average remaining lease term (years)		
Operating leases	**19.6**	27.8
Finance leases	**14.9**	n/a
Weighted average discount rate (%)		
Operating leases	**3.5**	4.1
Finance leases	**2.9**	n/a

As at		**December 31, 2019**		January 1, 2019
Operating Leases				
Operating lease right of use assets[(a)]	**$**	**8.3**	$	5.3
Current[(b)]	**$**	**1.3**	$	1.1
Long-term		**7.0**		4.2
Total operating lease liabilities	**$**	**8.3**	$	5.3
Finance Leases				
Finance lease right of use assets, net[(c)]	**$**	**0.5**	$	—
Current portion of long-term debt	**$**	**—**	$	—
Long-term debt		**0.5**		—
Total finance lease liabilities	**$**	**0.5**	$	**—**

(a) Included under the line item "Other long-term assets" on the Consolidated Balance Sheet.
(b) Included under the line item "Other current liabilities" on the Consolidated Balance Sheet.
(c) Included under the line item "Property, plant and equipment" on the Consolidated Balance Sheet.

Maturity analysis of lease liabilities during the next five years and thereafter is as follows:

As at December 31, 2019		**Operating Leases**	**Finance Leases**
2020	**$**	1.7	—
2021		1.6	—
2022		1.0	—
2023		0.7	—
2024		0.7	—
Thereafter		7.6	0.6
Total lease payments	**$**	13.3	0.6
Less: imputed interest		(5.0)	(0.1)
Total	**$**	8.3	0.5

The following table summarizes the lease expense recognized in the Consolidated Statement of Income:

		Year ended December 31 2019
Operating lease cost		
Operating leases	**$**	**1.3**
Short-term leases		**0.2**
Variable lease payments not included in the determination of lease liabilities		**0.3**
Total operating lease cost[(a)]		**1.8**
Finance lease cost		
Amortization of right-of-use assets		**—**
Interest on lease liabilities		**—**
Total finance lease cost		**—**
Total lease cost	**$**	**1.8**

(a) Included under the line item "Operating and administrative" on the Consolidated Statement of Income.

The following table provides supplemental information related to leases:

		Year ended December 31 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows used for operating leases	**$**	**1.3**
Operating cash flows used for finance leases	**$**	**—**
Financing cash flows used for finance leases	**$**	**—**
Right of use assets obtained in exchange for new lease liabilities:		
Operating leases	**$**	**4.0**
Finance leases	**$**	**0.5**

9. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Description	**Location**	**Ownership Percentage**		**December 31, 2019**		December 31, 2018
Inuvik Gas Ltd.	Canada	33.333	**$**	**—**	$	—
Coast LP	Canada	10		**118.4**		118.9
			$	**118.4**	$	118.9

Summarized financial information, assuming a 100% ownership interest in the equity investments listed above, is as follows:

Year ended December 31		**2019**		2018
Revenues	**$**	**148.7**	$	111.4
Expenses		**(74.6)**		(68.4)
	$	**74.1**	$	43.0

As at		**December 31, 2019**		December 31, 2018
Current assets	**$**	**29.6**	$	15.1
Property, plant and equipment	**$**	**1,068.1**	$	1,089.8
Intangible assets	**$**	**243.5**	$	246.3
Current liabilities	**$**	**(26.4)**	$	(24.7)
Other long-term liabilities	**$**	**(131.6)**	$	(137.4)

During the year ended December 31, 2019, a distribution of $8.0 million was received from Coast LP while during the year ended December 31, 2018, a distribution of $24.8 million was received from Coast LP. Of the $24.8 million received in 2018, $20.3 million was related to a special distribution due to a change in ownership in Coast LP and was redistributed to AltaGas prior to the Acquisition.

10. SHORT-TERM DEBT

As at December 31, 2019, the Company held a $35.0 million (December 31, 2018 - $35.0 million) revolving operating credit facility with a Canadian chartered bank. Borrowings under this facility are due on demand. Draws on this facility are by way of overdraft, Canadian prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and LIBOR loans. As at December 31, 2019, outstanding overdraft under this facility were $0.9 million (December 31, 2018 - $nil). Letters of credit outstanding under this facility as at December 31, 2019 were $3.8 million (December 31, 2018 - $4.0 million).

As at December 31, 2019, the Company held a $25.0 million (December 31, 2018 - $25.0 million) bank operating facility which is available for PNG's working capital purposes and expires on May 4, 2021. Draws on this facility are by way of prime-rate advances, bankers' acceptances or letters of credit at the bank's prime rate or for a fee. As at December 31, 2019, prime-rate advances under the operating facility were $11.2 million (December 31, 2018 - $5.8 million). Letters of credit outstanding under this facility as at December 31, 2019 were $3.9 million (December 31, 2018 - $3.7 million).

11. LONG-TERM DEBT

As at	Maturity date	**December 31, 2019**	December 31, 2018
Credit facilities			
$200 million unsecured revolving credit facility[(a)(c)]	31-Dec-2023	**$ 46.4**	$ 47.9
$25 million PNG committed credit facility[(a)]	4-May-2023	**25.0**	19.0
Debenture notes			
PNG 2025 series debenture - 9.30 percent[(b)]	18-Jul-2025	**12.0**	12.5
PNG 2027 series debenture - 6.90 percent[(b)]	2-Dec-2027	**13.0**	13.5
Unsecured term loan	25-Oct-2020	**14.0**	249.4
Medium term notes			
$300 million senior unsecured - 4.26 percent	5-Dec-2028	**300.0**	300.0
$250 million senior unsecured - 3.15 percent	6-Apr-2026	**250.0**	—
Finance lease liabilities *(note 8)*		**0.5**	—
		$ 660.9	$ 642.3
Less debt issuance costs and discount		**(3.3)**	(2.5)
		$ 657.6	$ 639.8
Less current portion		**(14.8)**	(1.0)
		$ 642.8	$ 638.8

(a) Borrowings on the credit facility can be by way of Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans.

(b) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of PNG's PP&E and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

(c) On February 13, 2020, the maturity date of the $200 million unsecured revolving credit facility was extended to December 31, 2023.

Principal repayments of long-term debt during the next five years and thereafter are as follows:

As at	
2020	$ 15.0
2021	$ 1.0
2022	$ 1.0
2023	$ 72.4
Thereafter	$ 571.5
	$ 660.9

12. ASSET RETIREMENT OBLIGATIONS

As at		**December 31, 2019**		December 31, 2018
Balance, beginning of year	**$**	**1.8**	$	1.2
Revision in estimated cash flow		**1.2**		0.5
Accretion expense		**0.1**		0.1
Balance, end of year	**$**	**3.1**	$	1.8

The Company estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2019 was $8.1 million (December 31, 2018 - $7.9 million).

Asset retirement obligations have been recorded in the consolidated financial statements at estimated values discounted at rates between 2.4 and 7.5 percent and are expected to be incurred between 2024 and 2044. No assets have been legally restricted for settlement of the estimated liability.

13. ACCUMULATED OTHER COMPREHENSIVE LOSS

($ millions)		**Defined benefit pension and Post-Retirement Benefits plans**
Opening balance, January 1, 2019	$	**(0.4)**
OCI before reclassification		**(0.9)**
Current period OCI (pre-tax)		**(0.9)**
Income tax on amounts retained in AOCI		**0.2**
Net current period OCI		**(0.7)**
Ending balance, December 31, 2019		**(1.1)**
Opening balance, January 1, 2018	$	(0.6)
OCI before reclassification		0.3
Current period OCI (pre-tax)		0.3
Income tax on amounts retained in AOCI		(0.1)
Net current period OCI		0.2
Ending balance, December 31, 2018		(0.4)

14. REVENUE

The following table disaggregates revenue by major sources:

Year ended December 31, 2019

	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	**$ —**	**$ 309.4**	**$ —**	**$ 309.4**
Other	**—**	**1.6**	**—**	**1.6**
Total revenue from contracts with customers	**$ —**	**$ 311.0**	**$ —**	**$ 311.0**
Other sources of revenue				
Revenue from alternative revenue programs (a)	**$ —**	**$ (5.7)**	**$ —**	**$ (5.7)**
Leasing revenue (b)	**14.8**	**—**	**—**	**14.8**
Other	**—**	**6.2**	**—**	**6.2**
Total revenue from other sources	**$ 14.8**	**$ 0.5**	**$ —**	**$ 15.3**
Total revenue	**$ 14.8**	**$ 311.5**	**$ —**	**$ 326.3**

(a) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.

(b) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

Year ended December 31, 2018

	Renewable Energy	Utilities	Corporate	Total
Revenue from contracts with customers				
Gas sales and transportation services	$ —	$ 289.3	$ —	$ 289.3
Other	—	1.8	—	1.8
Total revenue from contracts with customers	$ —	$ 291.1	$ —	$ 291.1
Other sources of revenue				
Revenue from alternative revenue programs (a)	$ —	$ (1.1)	$ —	$ (1.1)
Leasing revenue (b)	15.2	—	—	15.2
Other	—	3.9	—	3.9
Total revenue from other sources	$ 15.2	$ 2.8	$ —	$ 18.0
Total revenue	$ 15.2	$ 293.9	$ —	$ 309.1

(a) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.

(b) Relates to power sold to BC Hydro under the power purchase agreement for the Bear Mountain Wind Park, which is accounted for as an operating lease. The lease revenue earned are from variable lease payments which are recorded when actual electricity is generated and delivered.

The carrying value of PP&E associated with leasing revenue was $139.8 million as at December 31, 2019 (December 31, 2018 - $147.1 million).

Accounts receivable as at December 31, 2019 include unbilled receivables of $17.7 million (December 31, 2018 - $15.7 million) related to gas sales and transportation services rendered to customers but not billed at period end.

Transaction price allocated to the remaining obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied as at December 31, 2019:

	2020	2021	2022	2023	2024	> 2024	Total
Gas sales and transportation services	$ 34.0	$ 29.9	$ 18.6	$ 17.1	$ 15.8	$ 197.7	**$ 313.1**

The Company applies the practical expedient available under ASC 606 and does not disclose information about the remaining performance obligations for (i) contracts with an original expected length of one year or less, (ii) contracts for which revenue is recognized at the amount to which the Company has the right to invoice for performance completed, and (iii) contracts with variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation. In addition, the table above does not include any estimated amounts of variable consideration that are constrained. The majority of gas sales and transportation service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as gas is delivered or as service is provided.

15. INCOME TAXES

		Year ended December 31
	2019	2018
Income before income taxes	**$ 46.5**	$ 47.5
Statutory income tax rate (%)	**26.5**	27.0
Expected taxes at statutory rates	**$ 12.3**	$ 12.8
Add (deduct) the tax effect of:		
Permanent differences between accounting and tax basis of assets and liabilities	**0.5**	(3.7)
Rate adjustments to enacted Canadian rates	**0.8**	0.5
Change in tax basis of investments	**(15.1)**	—
Change in valuation allowance	**13.4**	1.2
Other	**(0.2)**	(0.3)
Deferred income tax recovery on regulated assets	**(7.3)**	(8.3)
Income tax provision	**$ 4.4**	$ 2.2
Current	**$ 2.2**	$ 3.5
Deferred	**2.2**	(1.3)
	$ 4.4	$ 2.2
Effective income tax rate (%)	**9.5**	4.6

Net deferred income tax liabilities comprise of the following:

As at	**December 31, 2019**	December 31, 2018
PP&E and intangible assets	**$ 75.6**	$ 72.8
Investments	**19.1**	36.2
Regulatory assets	**53.2**	44.6
Deferred compensation	**(4.1)**	(7.8)
Non-capital losses	**(22.0)**	(24.2)
Tax pools	**(2.6)**	(3.0)
Valuation allowance	**17.2**	3.8
Other	**(0.1)**	0.2
	$ 136.3	$ 122.6

The amount shown on the Consolidated Balance Sheets as deferred income tax liabilities represents the net differences between the tax basis and book carrying values on the Company's balance sheets at enacted tax rates.

As at December 31, 2019, the Company had non-capital losses of approximately $78.9 million (December 31, 2018 - $84.6 million), which expire between 2035 and 2039.

As at December 31, 2019 and 2018, the Company had no provision for uncertain tax positions.

16. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments consist of accounts receivable, foreign exchange contracts, accounts payable and accrued liabilities, short-term debt, current portion of long-term debt, and long-term debt.

Fair Value Hierarchy

The Company categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used.

Level 2 - fair values are determined based on valuation models and techniques where inputs other than quoted prices included within level 1 are observable for the asset or liability either directly or indirectly. The Company uses derivative instruments to manage fluctuations in foreign exchange rates. The Company estimates forward prices based on published sources.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. The Company uses valuation techniques when observable market data is not available.

Accounts receivable, accounts payable and accrued liabilities, and short-term debt - the carrying amounts approximate fair value because of the short maturity of these instruments.

					December 31, 2019
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	**$ 0.8**	**$ —**	**$ 0.8**	**$ —**	**$ 0.8**
Amortized cost					
Current portion of long-term debt [(a)]	**$ 15.0**	**$ —**	**$ 15.0**	**$ —**	**$ 15.0**
Long-term debt [(a)]	**645.9**	**—**	**686.8**	**—**	**686.8**
	$ 661.7	**$ —**	**$ 702.6**	**$ —**	**$ 702.6**

(a) Excludes deferred financing costs and debt discount.

	Carrying Amount	Level 1	Level 2	Level 3	December 31, 2018 Total Fair Value
Financial assets					
Fair value through net income					
Foreign exchange contracts asset	$ 1.4	$ —	$ 1.4	$ —	$ 1.4
	$ 1.4	$ —	$ 1.4	$ —	$ 1.4
Financial liabilities					
Amortized cost					
Current portion of long-term debt [(a)]	$ 1.0	$ —	$ 1.1	$ —	$ 1.1
Long-term debt [(a)]	641.3	—	650.7	—	650.7
	$ 642.3	$ —	$ 651.8	$ —	$ 651.8

(a) Excludes deferred financing costs and debt discount.

Risks associated with financial instruments

The Company is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in currency exchange rates and interest rates as well as credit risk and liquidity risk.

Foreign Exchange Risk

A vast majority of HGL's natural gas supply costs are denominated in U.S. dollars. Although all natural gas procurement costs, including any realized foreign exchange gains or losses are passed through to its customers, the Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in gas costs for customers as a result of changes in foreign exchange rates. As at December 31, 2019, the Company had outstanding foreign exchange forward contracts for US$31.5 million at an average rate of $1.32 Canadian per U.S. dollar. As at December 31, 2018, the Company had outstanding foreign exchange forward contracts for US$23.6 million at an average rate of $1.30 Canadian per U.S. dollar.

Interest Rate Risk

The Company is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Company manages interest rate risk by holding a mix of both fixed and floating interest rate debt. In addition, the Company's strategy is to optimize financing plans to maintain credit ratings to minimize interest costs. The Company proactively monitors and manages its debt maturity profile and debt covenants and maintains financial flexibility through access to multiple credit facilities.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract. The Company's maximum credit exposure consists primarily of the carrying value of accounts receivable and the fair value of derivative financial assets. The Company's utilities business generally has a large and diversified customer base, which minimizes the concentration of credit risk. To minimize credit risk, the utilities business will request for a security deposit which is eligible for refund after an observable period of compliance with payment terms. A credit report may also be requested. For the Company's renewable generation assets, all power generated are sold under the electricity purchase agreement with BC Hydro, an investment grade counterparty.

Accounts Receivable Past Due or Impaired

The Company had the following past due or impaired accounts receivable (AR):

As at December 31, 2019	**Total**	**AR accruals**	**Receivables impaired**	**Less than 30 days**	**31 to 60 days**	**61 to 90 days**	**Over 90 days**
Trade receivable	**$ 62.0**	**$ 17.7**	**1.0**	**40.7**	**1.8**	**0.3**	**0.5**
Other	**3.6**	**0.8**	**—**	**2.8**	**—**	**—**	**—**
Allowance for credit losses	**(1.0)**	**—**	**(1.0)**	**—**	**—**	**—**	**—**
	$ 64.6	**$ 18.5**	**$ —**	**$ 43.5**	**$ 1.8**	**$ 0.3**	**$ 0.5**

As at December 31, 2018		Total		AR accruals		Receivables impaired		Less than 30 days		31 to 60 days		61 to 90 days		Over 90 days
Trade receivable	$	60.4	$	15.7	$	1.1	$	41.1	$	1.6	$	0.5	$	0.4
Other		5.1		3.3		—		1.8		—		—		—
Allowance for credit losses		(1.1)		—		(1.1)		—		—		—		—
	$	64.4	$	19.0	$	—	$	42.9	$	1.6	$	0.5	$	0.4

Allowance for credit losses		**2019**		Year ended December 31 2018
Balance, beginning of year	**$**	**1.1**	$	1.0
New allowance		**0.4**		0.4
Recovery of allowance		**0.2**		0.2
Allowance applied to uncollectible customer accounts		**(0.7)**		(0.5)
Balance, end of year	**$**	**1.0**	$	1.1

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. The Company's objective is to ensure it has access to debt and equity funding as required. The Company's strategy is to maintain and comply with debt covenants to minimize financing costs.

The Company had the following contractual maturities with respect to financial liabilities:

				Payments due by period					
As at December 31, 2019		**Total**		**Less than 1 year**		**1-3 years**		**4-5 years**		**After 5 years**
Accounts payable and accrued liabilities	**$**	**62.1**	**$**	**62.1**	**$**	**—**	**$**	**—**	**$**	**—**
Short-term debt		**12.1**		**12.1**		**—**		**—**		**—**
Current portion of long-term debt [(a)]		**15.0**		**15.0**		**—**		**—**		**—**
Long-term debt [(a)]		**645.9**		**—**		**2.0**		**72.4**		**571.5**
	$	**735.1**	**$**	**89.2**	**$**	**2.0**	**$**	**72.4**	**$**	**571.5**

(a) Excludes deferred financing costs

As at December 31, 2018		Total		Less than 1 year		1-3 years		4-5 years		After 5 years
										Payments due by period
Accounts payable and accrued liabilities	$	64.9	$	64.9	$	—	$	—	$	—
Short-term debt		5.8		5.8		—		—		—
Current portion of long-term debt [(a)]		1.0		1.0		—		—		—
Long-term debt [(a)]		641.3		—		251.4		68.9		321.0
	$	713.0	$	71.7	$	251.4	$	68.9	$	321.0

(a) Excludes deferred financing costs

17. SHAREHOLDERS' EQUITY

Authorized share capital

The Company is authorized to issue an unlimited number of voting common shares. The Company is also authorized to issue preferred shares not to exceed 50 percent share of the voting rights attached to the issued and outstanding common shares.

Common shares issued and outstanding

	Number of shares		Amount
As at January 1, 2018	143,140,001	$	—
Consolidation of common shares on a 28:1 basis	(138,027,858)		—
Shares issued to AltaGas in connection with the Acquisition	5,912,857		58.4
Shares issued on public offering, net of issuance costs (after tax)	16,500,000		228.1
Shares issued pursuant to the Over-Allotment Option (after tax)	2,475,000		34.5
As at December 31, 2018	30,000,000		321.0
As at December 31, 2019	**30,000,000**	**$**	**321.0**

On September 5, 2018, the Company consolidated its shares on a 28:1 basis.

On October 18, 2018, 5,912,857 shares were issued to AltaGas in connection with the Acquisition described under note 1. By resolution of the Board of Directors, the stated capital was increased by $58.4 million.

On October 25, 2018, the Company completed the IPO and issued 16,500,000 common shares at the IPO price of $14.50 per share for gross proceeds of $239.3 million (net proceeds of $228.1 million, after share issuance costs and tax of $11.2 million).

On November 21, 2018, a further 2,475,000 shares were issued pursuant to the Over-Allotment Option at the IPO price of $14.50 per share for gross proceeds of $35.9 million (net proceeds of $34.5 million, after share issuance costs and tax of $1.4 million).

Share Option Plan

Effective October 24, 2018, the Company has a Share Option Plan under which directors, officers and employees are eligible to receive grants. As at December 31, 2019, 965,234 shares were reserved for issuance under the plan. Options granted under the plan have a term between 6 years until expiry and vest no longer than over a 4 year period.

As at December 31, 2019, the unexpensed fair value of share option compensation cost associated with future periods was $0.9 million (December 31, 2018 - $0.3 million).

The following table summarizes information about the Company's share options:

As at	**December 31, 2019**			December 31, 2018		
	Number of options		**Exercise price [(a)]**	Number of options		Exercise price [(a)]
Share options outstanding, beginning of period	**200,375**	**$**	**14.65**	—	$	—
Granted	**334,391**		**20.90**	200,375		14.65
Share options outstanding, end of period	**534,766**	**$**	**18.56**	200,375	$	14.65
Share options exercisable, end of period	**50,095**	**$**	**14.65**	—	$	—

As at December 31, 2019, the aggregate intrinsic value of the total options exercisable was $0.9 million (December 31, 2018 - $nil), the total intrinsic value of options outstanding was $7.9 million (December 31, 2018 - $0.3 million) and the total intrinsic value of options exercised was $nil (December 31, 2018 - $nil).

The following table summarizes employee share options outstanding and exercisable as at December 31, 2019:

	Options outstanding				Options exercisable			
	Number outstanding		Weighted average exercise price	Weighted average remaining contractual life	Number exercisable		Weighted average exercise price	Weighted average remaining contractual life
$14.65	200,375	$	14.65	4.9	50,095	$	14.65	4.9
$15.73	11,888		15.73	5.0	—		—	—
$21.09	322,503		21.09	5.4	—		—	—
	534,766	**$**	**18.56**	**5.2**	**50,095**	**$**	**14.65**	**4.9**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option pricing model. The weighted average grant date fair value and assumptions are as follows:

Year ended December 31	**2019**
Fair value per option ($)	**3.18**
Risk-free interest rate (%)	**1.6**
Expected life (years)	**6.0**
Expected volatility (%)	**25.9**
Annual dividend yield (%)	**4.6**
Forfeiture rate (%)	**n/a**

MTIP and DSUP

The Company has a MTIP for employees and executive officers, which includes RSUs and PSUs with vesting periods of 36 months from the grant date. In addition, the Company has a DSUP, which allows granting of DSUs to directors. DSUs granted under the DSUP vests immediately but settlement of the DSUs occur when the individual ceases to be a director.

PSUs, RSUs, and DSUs	**2019**	2018
(number of units)		
Balance, beginning of period	**92,502**	—
Granted	**126,123**	92,502
Units in lieu of dividends	**7,307**	—
Outstanding, end of period	**225,932**	92,502

For the year ended December 31, 2019, the compensation expense recorded for the MTIP and DSUP was $2.4 million (2018 - $0.1 million). As at December 31, 2019, the unrecognized compensation expense relating to the remaining vesting period for the MTIP was $5.0 million (December 31, 2018 - $1.4 million). All RSUs and PSUs will vest immediately upon the occurrence of a change of control transaction.

18. NET INCOME PER COMMON SHARE

Basic net income per common share is based on net income after taxes and is calculated using the weighted average number of common shares outstanding during the periods presented. For comparative purposes, the consolidation of common shares on a 28:1 basis and the common shares issued pursuant to the IPO, including the Over-Allotment Option, have been assumed to have occurred as of the beginning of 2018.

The following table summarizes the computation of net income per common share:

				Year ended December 31
		2019		2018
Numerator:				
Net income after taxes	**$**	**42.1**	$	45.3
Denominator *(millions)*:				
Weighted average number of common shares outstanding - basic		**30.0**		30.0
Dilutive equity instruments		**0.1**		—
Weighted average number of common shares outstanding - diluted		**30.1**		30.0
Basic net income per common share	**$**	**1.40**	$	1.51
Diluted net income per common share	**$**	**1.40**	$	1.51

For the year ended December 31, 2019, 0.3 million of share options (2018 – nil) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

19. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

The Company has a defined contribution ("DC") pension plan for substantially all employees who are not members of defined benefit plans. The pension cost recorded for the DC plan was $0.5 million for the year ended December 31, 2019 (2018 - $0.4 million).

Defined Benefit Plans and Post-Retirement Benefits

The Company has several defined benefit plans and post-retirement benefit plans for unionized and non-unionized employees. All defined benefit plans are funded. The post-retirement benefit plans are not funded except for one plan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

Supplemental Executive Retirement Plan (SERP)

The Company has non-registered, defined benefit pension plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Company as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Actuarial valuation

The Company's most recent actuarial valuation of its defined benefit plans for funding purposes was completed as at December 31, 2016. The Company is required to file an actuarial valuation of its Canadian defined benefit plans with the pension regulators at least every three years. The next actuarial valuation for funding purposes is being completed as at December 31, 2019 and is expected to be filed with the pension regulators in 2020. The following table summarizes details of the Company's defined benefit plans, including the SERP and post-retirement plans:

Year ended December 31, 2019		**Defined Benefit**		**Post-Retirement Benefits**		**Total**
Accrued benefit obligation						
Balance, beginning of year	**$**	**117.2**	**$**	**13.2**	**$**	**130.4**
Actuarial (gain) loss		**12.5**		**(1.2)**		**11.3**
Current service cost		**6.3**		**0.6**		**6.9**
Member contributions		**0.1**		**—**		**0.1**
Interest cost		**4.5**		**0.5**		**5.0**
Benefits paid		**(4.4)**		**(0.3)**		**(4.7)**
Expenses paid		**(0.2)**		**—**		**(0.2)**
Balance, end of year	**$**	**136.0**	**$**	**12.8**	**$**	**148.8**
Plan assets						
Fair value, beginning of year	**$**	**91.9**	**$**	**8.8**	**$**	**100.7**
Actual return on plan assets		**11.1**		**0.4**		**11.5**
Employer contributions		**6.8**		**0.5**		**7.3**
Member contributions		**0.1**		**—**		**0.1**
Benefits paid		**(4.4)**		**(0.3)**		**(4.7)**
Expenses paid		**(0.2)**		**—**		**(0.2)**
Fair value, end of year	**$**	**105.3**	**$**	**9.4**	**$**	**114.7**
Net amount recognized	**$**	**(30.7)**	**$**	**(3.4)**	**$**	**(34.1)**

Year ended December 31, 2018		Defined Benefit		Post-Retirement Benefits		Total
Accrued benefit obligation						
Balance, beginning of year	$	117.2	$	13.2	$	130.4
Actuarial gain		(6.3)		(0.9)		(7.2)
Current service cost		6.5		0.7		7.2
Member contributions		0.1		—		0.1
Interest cost		4.1		0.5		4.6
Benefits paid		(4.2)		(0.3)		(4.5)
Expenses paid		(0.2)		—		(0.2)
Balance, end of year	$	117.2	$	13.2	$	130.4
Plan assets						
Fair value, beginning of year	$	92.5	$	8.3	$	100.8
Actual return on plan assets		(1.8)		(0.2)		(2.0)
Employer contributions		5.5		1.0		6.5
Member contributions		0.1		—		0.1
Benefits paid		(4.2)		(0.3)		(4.5)
Expenses paid		(0.2)		—		(0.2)
Fair value, end of year	$	91.9	$	8.8	$	100.7
Net amount recognized	$	(25.3)	$	(4.4)	$	(29.7)

The following amounts were included in the Consolidated Balance Sheet:

	December 31, 2019						December 31, 2018					
		Defined Benefit		**Post-Retirement Benefits**		**Total**		Defined Benefit		Post-Retirement Benefits		Total
Other long-term assets	**$**	**—**	**$**	**2.5**	**$**	**2.5**	$	—	$	0.4	$	0.4
Future employee obligations		**(30.7)**		**(5.9)**		**(36.6)**		(25.3)		(4.8)		(30.1)
	$	**(30.7)**	**$**	**(3.4)**	**$**	**(34.1)**	$	(25.3)	$	(4.4)	$	(29.7)

The funded status based on the accumulated benefit obligation for all defined benefit plans were:

As at		**December 31, 2019**		December 31, 2018
Accumulated benefit obligation [(a)]	**$**	**(119.8)**	$	(101.5)
Fair value of plan assets		**105.3**		91.9
Funded status	**$**	**(14.5)**	$	(9.6)

(a) Accumulated benefit obligation differs from future employee obligations accrued on the balance sheet in that it does not include an assumption with respect to future compensation levels.

The following amounts were not recognized in the net periodic benefit cost and recorded in other comprehensive losses:

Year ended December 31, 2019		**Defined Benefit**		**Post-Retirement Benefits**		**Total**
Net actuarial loss	**$**	**(0.4)**	**$**	**(1.1)**	**$**	**(1.5)**
Recognized in AOCI pre-tax	**$**	**(0.4)**	**$**	**(1.1)**	**$**	**(1.5)**
Increase by the amount included in deferred tax liabilities		**0.1**		**0.3**		**0.4**
Net amount in AOCI after-tax	**$**	**(0.3)**	**$**	**(0.8)**	**$**	**(1.1)**

Year ended December 31, 2018		Defined Benefit		Post-Retirement Benefits		Total
Net actuarial loss	$	(0.3)	$	(0.3)	$	(0.6)
Recognized in AOCI pre-tax	$	(0.3)	$	(0.3)	$	(0.6)
Increase by the amount included in deferred tax liabilities		0.1		0.1		0.2
Net amount in AOCI after-tax	$	(0.2)	$	(0.2)	$	(0.4)

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

The net pension expense by plan for the period was as follows:

Year ended December 31, 2019		**Defined Benefit**		**Post-Retirement Benefits**		**Total**
Current service cost [(a)]	**$**	**6.3**	**$**	**0.6**	**$**	**6.9**
Interest cost [(b)]		**4.5**		**0.5**		**5.0**
Expected return on plan assets [(b)]		**(5.7)**		**(0.3)**		**(6.0)**
Amortization of regulatory asset [(b)]		**1.2**		**—**		**1.2**
Net benefit cost recognized	**$**	**6.3**	**$**	**0.8**	**$**	**7.1**

(a) Recorded under the line item "Operating and administrative" expenses on the Consolidated Statement of Income
(b) *Recorded under the line item "Other loss" on the Consolidated Statement of Income.*

Year ended December 31, 2018		Defined Benefit		Post-Retirement Benefits		Total
Current service cost [(a)]	$	6.5	$	0.7	$	7.2
Interest cost [(b)]		4.1		0.5		4.6
Expected return on plan assets [(b)]		(5.7)		(0.3)		(6.0)
Amortization of regulatory asset [(b)]		1.5		—		1.5
Net benefit cost recognized	$	6.4	$	0.9	$	7.3

(a) Recorded under the line item "Operating and administrative" expenses on the Consolidated Statement of Income
(b) Recorded under the line item "Other loss" on the Consolidated Statement of Income.

The objective of the Company's investment policy is to maximize long-term total return while protecting the capital value of the fund from major market fluctuations through diversification and selection of investments.

The objective for fund returns, over three to five-year periods, is the sum of two components - a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management. It is the Company's belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three-to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each fund manager's mandate. There is also the risk of annual volatility in returns, which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the fund manager(s) within the constraints prescribed by their mandate(s).

The Company has a target asset mix of 45 percent to 55 percent fixed income assets. These objectives take into account the nature of the liabilities and the risk-reward tolerance of the Company.

The collective investment mixes for the plans are as follows as at December 31, 2019:

	Fair value	Level 1	Level 2	Level 3	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ **5.1**	$ 5.1	$ —	$ —	4.4
Canadian equities	**38.7**	38.7	—	—	33.7
Foreign equities	**18.2**	18.2	—	—	15.9
Fixed income	**46.2**	46.2	—	—	40.3
Real estate	**6.5**	—	6.5	—	5.7
	$ **114.7**	$ 108.2	$ 6.5	$ —	100.0

Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Year ended December 31	**2019**		2018	
Discount rate (%)	**3.10 - 4.10**	**3.90**	2.80 - 3.60	3.60
Expected long-term rate of return on plan assets (%) [(a)]	**0.00 - 6.08**	**3.10**	0.00 - 6.20	3.10
Rate of compensation increase (%)	**0.00 - 3.50**	**3.25**	0.00 - 3.25	3.25
Average remaining service life of active employees (years)	**15.0**	**14.7**	14.7	14.7

(a) Only applicable for funded plans

Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
As at December 31	**2019**		2018	
Discount rate (%)	**2.50 - 3.20**	**3.16 - 3.17**	3.10 - 4.10	3.90
Rate of compensation increase (%)	**0.00 - 3.50**	**3.00**	0.00 - 3.50	3.25

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 6.2 percent and the ultimate trend rate is 4.00 percent, which is expected to be achieved by 2040.

The assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percentage point change in the assumed health care trend rates would have the following effects for 2019:

		Increase		Decrease
Service and interest costs	$	0.3	$	(0.2)
Accrued benefit obligation	$	2.1	$	(1.6)

The following table shows the expected cash flows for defined benefit pension and other-post retirement plans:

		Defined Benefit		Post-Retirement Benefits
Expected employer contributions:				
2020	$	6.7	$	0.1
Expected benefit payments:				
2020	$	4.3	$	0.3
2021		4.5		0.3
2022		4.7		0.4
2023		4.9		0.4
2024		5.2		0.4
2025-2029	$	29.0	$	2.4

20. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

The Company has long-term natural gas purchase and transportation arrangements, service agreements and operating and finance leases, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments at December 31, 2019 are estimated as follows:

		2020		2021		2022		2023		2024		2025 and beyond		**Total**
Gas purchase and transportation [(a)]	$	40.5	$	36.1	$	24.3	$	20.1	$	18.8	$	200.8	**$**	**340.6**
Service agreement [(b)]		7.0		4.8		1.2		1.3		1.3		10.1		**25.7**
Operating and finance leases [(c)]		1.7		1.6		1.0		0.7		0.7		8.2		**13.9**
	$	49.2	$	42.5	$	26.5	$	22.1	$	20.8	$	219.1	**$**	**380.2**

(a) The Company enters into contracts to purchase natural gas and natural gas transportation services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2020 to 2040, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

(b) In 2007, the Company entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain Wind Park. The Company has an obligation to pay a minimum of $4 million over the next two years. In 2019, the Company entered into a long-term agreement for software implementation, hosting and maintenance. The Company is obligated to pay approximately US$17.0 million over the 12 year term of the contract.

(c) Operating and finance leases include lease arrangements for office spaces, land, and office and other equipment.

Guarantees

In October 2014, HGL entered into a throughput service contract with Enbridge Inc. (formerly Spectra Energy Corp.) for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (the Atlantic Bridge Project). The contract will commence upon completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas issued two guarantees with an aggregate maximum liability of US$91.7 million, guaranteeing HGL's payment obligations under the throughput service contract with Enbridge Inc. Effective October 25, 2018, the two guarantees issued by AltaGas were cancelled and reissued by the Company.

On October 22, 2018, the Company issued a guarantee with a maximum liability of $0.3 million related to the right of way for permanent access and power line access at Bear Mountain Wind Park.

The Company, through HGL has agreements in place with Union Gas Limited ("UGL") to deliver natural gas. In October 25, 2018, the Company issued a guarantee with a maximum liability of $0.3 million guaranteeing UGL's reasonable costs incurred to enforce obligations created under those agreements.

The Company, through HGL has agreements in place with Maritimes & Northeast Pipeline Limited Partnership ("M&NP") to store or transport natural gas. On December 1, 2019, the Company issued a guarantee with a maximum liability of $3.0 million guaranteeing M&NP's reasonable costs incurred to enforce obligations created under those agreements.

Contingencies

The Company is subject to various legal claims and actions arising in the normal course of the Company. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Company does not believe that the resolution of such claims and actions will have a material impact on the Company's consolidated financial position or results of operations.

21. RELATED PARTY TRANSACTIONS AND BALANCES

Pre-Acquisition Relationship with AltaGas

Prior to the Acquisition, the Company has historically been managed and operated in the normal course of business by AltaGas along with other AltaGas affiliates. Accordingly, certain shared costs have been allocated to the Company and reflected as expenses in the consolidated financial statements. Management of AltaGas and the Company consider the allocation methodologies used to be reasonable and appropriate reflections of the related expenses attributable to the Company for purposes of the consolidated financial statements; however, the expenses reflected may not be indicative of the actual expenses that would have been incurred during the year ended December 31, 2018 as presented if the Company historically operated as a separate entity.

Net Parental Investment

AltaGas' net investment in the Company pre-acquisition is presented as "Net Parental Investment". In lieu of shareholder's equity in the consolidated financial statements as there was no share ownership between AltaGas and the Acquired Assets (as the Acquired Assets were not a separate legal entity).

Pension and Other Post-Employment Benefit Plans

The Company sponsors several pension and post-employment plans. In addition, the Company's employees also participate in certain pension plans and post-employment benefit plans sponsored by AltaGas prior to the IPO. There is no contractual agreement or stated policy between the Company and AltaGas for charging the costs of these plans.

All obligations pursuant to these plans were obligations of AltaGas. AltaGas allocated to the Company, the net periodic benefit costs associated with employees that are beneficiaries of pensions and other employment benefit costs. These costs are included in operating and administrative expenses and other loss in the consolidated statement of income for the year ended December 31, 2018. AltaGas contributes to these plans. The amount contributed to certain of these plans by AltaGas on the Company's behalf cannot be determined.

Derivatives

Some of the derivatives held that relate to the Company are entered into on behalf of the Company by an AltaGas entity during the year ended December 31, 2018.

Allocated Corporate Costs

Allocated costs include AltaGas charges including, but not limited to: board of directors, executive management, finance, accounting and tax, legal and compliance, office services and corporate resources, information technology and procurement. These costs are included in operating and administrative expenses in the consolidated statement of income for the year ended December 31, 2018 have a pre-tax total of $7.5 million. The costs were allocated to the Company based on similar methodology used to allocate costs within AltaGas, which is a combination of asset values, payroll expenses and earnings. Note that these expenses may have been different had the Company been a separate entity during the periods presented.

Transition Services Agreement

Concurrent with the Acquisition on October 18, 2018, the Company entered into a Transition Services Agreement with AltaGas pursuant to which AltaGas provides certain general administrative and corporate services required by the Company, which include: accounting, tax, finance, legal and regulatory, payroll, corporate human resources and pension management, environmental, health and safety administration, procurement, enterprise resource planning and information technology. AltaGas provides the services on a cost recovery basis only. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances, and is extendable by mutual agreement of the parties.

Related party balances

Amounts due to or from related parties on the Consolidated Balance Sheets, arising from transactions with joint ventures and AltaGas and its affiliates, are measured at the exchange amount and are as follows:

As at		**December 31, 2019**		December 31, 2018
Due from related parties				
Foreign exchange contracts asset - current [(a)]	**$**	**—**	$	0.9
	$	**—**	$	0.9
Due to related parties				
Accounts payable [(b)]	**$**	**14.3**	$	16.4
	$	**14.3**	$	16.4

(a) Foreign exchange hedges with AltaGas.

(b) Payables to AltaGas and affiliates of AltaGas.

Related party transactions

The following transactions with joint ventures and AltaGas and its affiliates are measured at the exchange amount and have been recorded on the Consolidated Statements of Income:

		Year ended December 31		
		2019		2018
Revenue [(a)]	**$**	**2.4**	$	3.9
Unrealized gain (loss) on foreign exchange contracts with AltaGas	**$**	**(0.9)**	$	1.2
Cost of sales [(b)]	**$**	**(100.8)**	$	(93.2)
Operating and administrative expenses [(c)]	**$**	**(1.9)**	$	(8.6)
Interest expense [(d)]	**$**	**—**	$	(22.1)

(a) In the normal course of business, the Company provided gas sales and transportation services to related parties.

(b) In the normal course of business, the Company purchased natural gas from a related party.

(c) Operating and administrative expenses include the allocation of corporate costs for the year ended December 31, 2018 from AltaGas, fees paid to AltaGas for transition services, and administrative costs recovered from affiliates.

(d) Interest expense on debt due to related parties.

22. SUPPLEMENTAL CASH FLOW INFORMATION

The following table details the changes in operating assets and liabilities:

		Year ended December 31		
		2019		2018
Source (use) of cash:				
Accounts receivable	**$**	**(2.7)**	$	0.6
Inventory		**—**		0.3
Other current assets		**1.1**		(2.8)
Regulatory assets (current)		**(1.0)**		0.2
Accounts payable and accrued liabilities		**(3.4)**		(4.5)
Customer deposits		**(0.8)**		1.1
Regulatory liabilities (current)		**(1.8)**		4.6
Other current liabilities		**0.9**		—
Net change in regulatory assets and liabilities (long-term)[(a)]		**7.9**		0.5
Other long-term assets		**(1.2)**		—
Changes in operating assets and liabilities	**$**	**(1.0)**	$	—

(a) Inclusive of a decrease in the revenue deficiency account (source of cash) of $6.8 million during the year ended December 31, 2019 (year ended December 31, 2018 – a decrease in the revenue deficiency account (source of cash) of $3.0 million).

The following cash payments have been included in the determination of net income after taxes:

		Year ended December 31		
		2019		2018
Interest paid	**$**	**28.1**	$	23.6
Income taxes paid (net of refunds)	**$**	**1.7**	$	1.4

23. SEGMENTED INFORMATION

The following describes the Company's three reporting segments:

Renewable Energy	–	Includes the 102 MW Bear Mountain Wind Park, and an approximately 10 percent indirect equity investment in Coast LP, which indirectly owns and operates three run-of-river hydroelectric power generation assets in northwest British Columbia.
Utilities	–	Includes the rate-regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia as well as an approximately 33.3 percent equity investment in Inuvik Gas Ltd.
Corporate	–	Includes the cost of providing shared services, financial and general corporate support and corporate assets.

The following tables show the composition by segment:

					Year ended December 31, 2019
	Utilities	**Renewable Energy**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 311.5**	**$ 14.8**	**$ —**	**$ —**	**$ 326.3**
Cost of sales	**(125.6)**	**(0.2)**	**—**	**—**	**(125.8)**
Operating and administrative	**(90.7)**	**(4.7)**	**(5.0)**	**—**	**(100.4)**
Accretion expenses	**(0.1)**	**—**	**—**	**—**	**(0.1)**
Depreciation and amortization	**(24.5)**	**(7.2)**	**—**	**—**	**(31.7)**
Income from equity investments	**—**	**7.4**	**—**	**—**	**7.4**
Unrealized loss on foreign exchange contracts	**(2.2)**	**—**	**—**	**—**	**(2.2)**
Other loss	**(0.1)**	**—**	**—**	**—**	**(0.1)**
Operating income (loss)	**$ 68.3**	**$ 10.1**	**$ (5.0)**	**$ —**	**$ 73.4**
Interest expense	**(3.8)**	**—**	**(23.1)**	**—**	**(26.9)**
Income (loss) before income taxes	**$ 64.5**	**$ 10.1**	**$ (28.1)**	**$ —**	**$ 46.5**
Net additions (reductions) to:					
Property, plant and equipment(a)	**$ 69.4**	**$ —**	**$ 0.3**	**$ —**	**$ 69.7**
Intangible assets	**$ 6.8**	**$ —**	**$ 0.1**	**$ —**	**$ 6.9**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash Flows due to classification differences.

					Year ended December 31, 2018
	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 294.0	$ 15.2	$ —	$ (0.1)	$ 309.1
Cost of sales	(117.1)	(0.2)	—	—	(117.3)
Operating and administrative	(87.1)	(5.2)	(0.3)	0.1	(92.5)
Accretion expenses	(0.1)	—	—	—	(0.1)
Depreciation and amortization	(21.7)	(7.2)	—	—	(28.9)
Income from equity investments	—	4.2	—	—	4.2
Unrealized gain on foreign exchange contracts	1.7	—	—	—	1.7
Other income (loss)	(0.2)	—	0.1	—	(0.1)
Foreign exchange loss	—	—	(0.1)	—	(0.1)
Operating income (loss)	$ 69.5	$ 6.8	$ (0.3)	$ —	$ 76.0
Interest expense	(23.7)	—	(4.8)	—	(28.5)
Income (loss) before income taxes	$ 45.8	$ 6.8	$ (5.1)	$ —	$ 47.5
Net additions (reductions) to:					
Property, plant and equipment(a)	$ 68.2	$ —	$ —	$ —	$ 68.2
Intangible assets	$ 3.2	$ —	$ —	$ —	$ 3.2

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash Flows due to classification differences

The following table shows goodwill and total assets by segment:

	Utilities	Renewable Energy	Corporate	Total
As at December 31, 2019				
Goodwill	**$ 119.1**	**$ —**	**$ —**	**$ 119.1**
Segmented assets	**$ 1,276.6**	**$ 262.4**	**$ 43.3**	**$ 1,582.3**
As at December 31, 2018				
Goodwill	$ 119.1	$ —	$ —	$ 119.1
Segmented assets	$ 1,244.9	$ 274.0	$ (3.4)	$ 1,515.5

24. SUBSEQUENT EVENTS

Subsequent events have been reviewed through March 4, 2020, the date on which these consolidated financial statements were approved for issue by the Board of Directors. Other than what has been described under note 11, there were no subsequent events requiring disclosure or adjustment to the consolidated financial statements.