2018 | ANNUAL REPORT

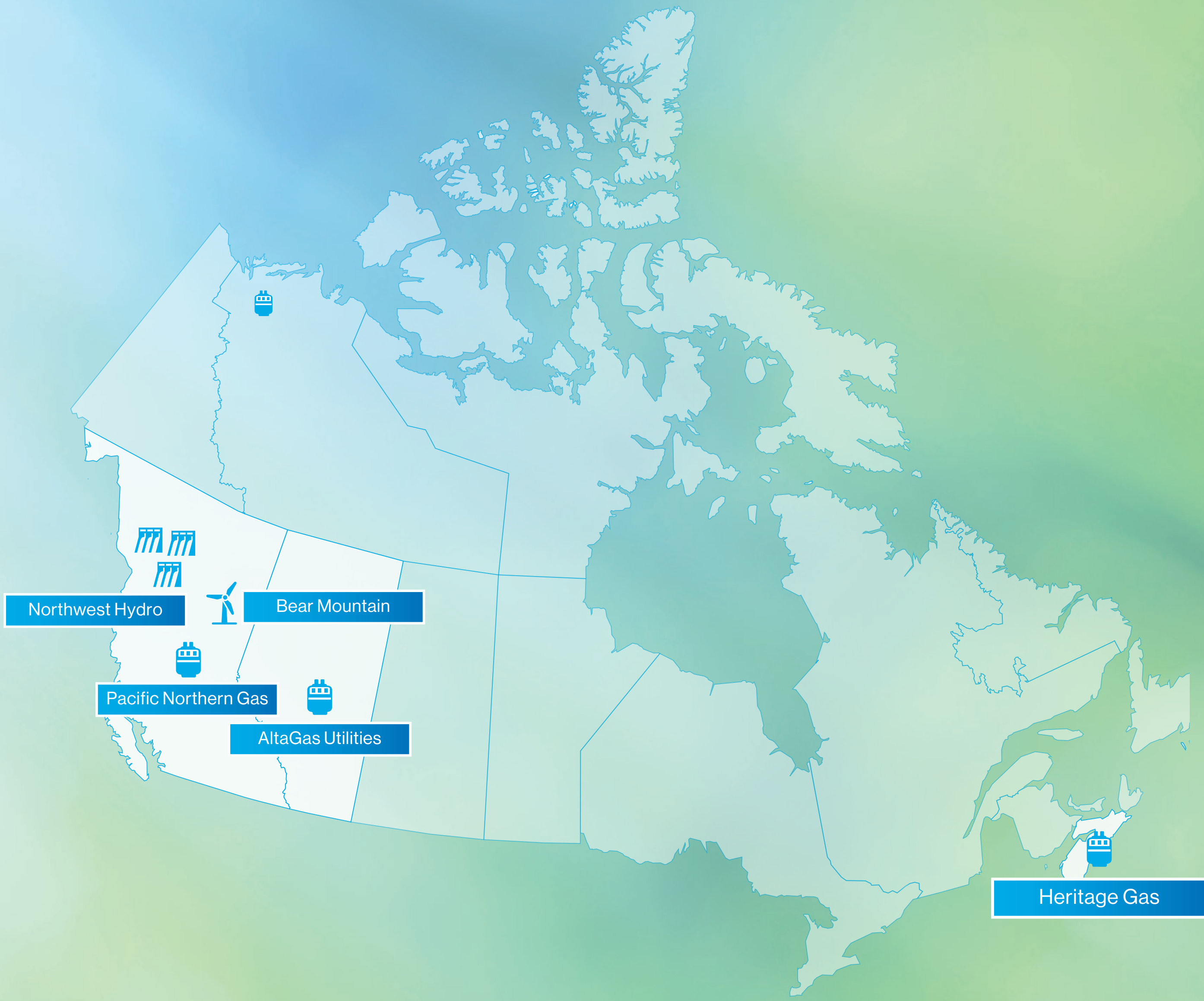
BUILDING A BRAND NEW COMPANY

AltaGas Canada

OUR OPERATIONS

LOW-RISK, LONG-TERM PROFITABLE GROWTH

$886 M	132 MW	100%	~130 K	431
in rate base (2018)	of net renewable generation	regulated/ contracted	natural gas utility customers	employees across Canada



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.

HYDRO POWER FACILITIES — WIND POWER FACILITY — UTILITY OPERATIONAL AREA

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 6, 2019 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, 2018. This MD&A should be read in conjunction with the accompanying audited consolidated financial statements as at and for the year ended December 31, 2018 (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 "*Utilities*" section in the annual information form of ACI dated March 6, 2019 (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: estimated cost and timing for the Etzikom Lateral Project (as defined herein), including timing of related AUC decisions; expectations regarding arrangements in relation to the Kitimat, British Columbia to Summit Lake, British Columbia pipeline and proposed loop; estimated timing for the Heritage Gas Limited Customer Retention Program; the expected accumulation of Heritage Gas Limited's revenue deficiency account; expected in-service date for the Atlantic Bridge Expansion Project; expected transition of Inuvik Gas to the Town of Inuvik; anticipated 2019 to 2023 financial results, net income growth, capital program, and rate base; anticipated sources of indebtedness; expected funding of the Company's capital program; planned expenditures under the approved capital budget; expected business environment and operational factors contributing to the Company's performance; and expected timing of regulatory approvals.

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: 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).

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*". The estimates of certain of the Company's financial results for the year ended December 31, 2018, assuming the Acquisition had been completed and the IPO had been closed at the beginning of the period, may constitute a financial outlook, but is not a forecast or projection of future results, and is based on management's assessment of the relevant information currently available. See "*Non-GAAP Financial Measures – Adjusted Normalized Net Income*".

These estimates are based on the same assumptions, risk factors, limitations and qualifications as set forth. In addition, the estimates are based on the Company's historical results of operations, using the expectations and assumptions set out in the footnotes to the table in "*Non-GAAP Financial Measures – Adjusted Normalized Net Income*" to develop the estimated values. 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: (a) the 2019 to 2023 outlook; and (b) results for the year ended December 31, 2018, assuming the Acquisition had been completed and the IPO had been closed at the beginning of the period, each as measured by certain operational and financial performance measures. 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* 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 Recent Developments"* 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, an approximately 10 percent indirect interest in the Northwest Hydro Facilities. 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, consistent returns with strong organic growth for investors through the ownership of rate-regulated utilities and renewable power assets contracted through long-term power purchase agreements ("PPAs") 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 RECENT DEVELOPMENTS

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. The Company repaid in full $34.0 million to AltaGas on November 21, 2018.

2018 FINANCIAL HIGHLIGHTS

(Normalized EBITDA, normalized funds from operations, normalized net income, adjusted 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 $45.3 million ($1.51 per Common Share) compared to $41.7 million ($1.39 per Common Share) in 2017.
- Normalized net income was $41.8 million ($1.39 per Common Share), a decrease of 2 percent compared to $42.5 million ($1.42 per Common Share) in 2017.
- Adjusted normalized net income was $40.5 million ($1.35 per Common Share).
- Operating income was $76.0 million, an increase of 1 percent compared to $75.2 million in 2017.
- Normalized EBITDA was $101.6 million, a decrease of 3 percent compared to $104.3 million in 2017.
- Normalized funds from operations were $88.1 million ($2.94 per Common Share), a 39 percent increase compared to $63.2 million ($2.11 per Common Share) in 2017.
- Net debt was $643.8 million as at December 31, 2018, compared to $552.9 million as at December 31, 2017.
- Net debt to total capitalization ratio was 51.4 percent as at December 31, 2018, compared to 40.7 percent as at December 31, 2017.
- On October 25, 2018, the Company executed:
  - A $200.0 million unsecured revolving credit facility with a syndicate of lenders having a term of four years subject to customary extension provisions available for general corporate purposes;
  - A $250.0 million unsecured term loan with a syndicate of lenders having a term of two years, which was fully drawn with the proceeds utilized to pay for a portion of the Purchase Price Short-Term Note; and
  - A $35.0 million unsecured, uncommitted demand operating facility, which is available for general corporate purposes.
- On December 5, 2018, ACI issued $300.0 million of medium-term notes (MTNs) with a coupon rate of 4.26 percent (4.269 percent yield to maturity) and maturity date of December 5, 2028. The proceeds were used to partially repay the Purchase Price Long-Term Note.
- On December 7, 2018, the Purchase Price Long-term Note was fully repaid.

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 $886 million of rate base as at December 31, 2018 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 corporate 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, 2018, AUI served approximately 80,400 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, 2018 was approximately $357 million. The Alberta Utilities Commission ("AUC") approved a Return on Equity ("ROE") of 8.5 percent on 41 percent equity for 2017. On August 2, 2018, the AUC approved an ROE of 8.5 percent on 39 percent equity for AUI 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 ("PBR 1"). 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 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 28 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 is expected to be completed in the fourth quarter of 2019 at a cost of approximately $10 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.

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 the end of December 2018, PNG served approximately 42,000 customers. Approximately 87 percent of PNG’s total customers are residential. PNG’s rate base as at December 31, 2018 was approximately $221 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 British Columbia Utilities Commission (“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 October 9, 2018, PNG published a request for expressions of interest in a multi-lateral process, in which PNG identified interested parties who require firm transportation service on its existing pipeline system for natural gas deliveries from Station 4a on the Enbridge Westcoast Energy Inc. southern mainline near the Summit Lake, British Columbia to the Terrace, British Columbia, Kitimat, British Columbia and Prince Rupert, British Columbia areas, as well as on a proposed expansion of its pipeline system from Summit Lake, British Columbia to Kitimat, British Columbia (the “PNG Looping Project”). PNG has subsequently invited interested parties to participate in its multi-lateral process and execute binding agreements, which will include the payment of reservation fees to reserve existing PNG transportation capacity, as well as support agreements, for a pro-rata share of the project Pre-FEED development costs to assess feasibility of its expansion project. Through the project development phase, option holders will be required to backstop PNG’s ongoing pipeline development costs, on a pro-rata basis, until such time transportation service agreements have been executed on an unconditional basis.

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, 2018, HGL’s customer base is approximately 7,300 customers. HGL has a mix of residential, small commercial, large commercial and industrial customers. For 2018 and 2017, HGL’s approved regulated ROE is 11 percent with an approved deemed capital structure of 45 percent equity. HGL’s rate base as at December 31, 2018 was approximately $308 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 Nova Scotia Utility and Review Board ("NSUARB"). In order to lower pricing for its commercial customers, HGL filed a customer retention program 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 (the "Customer Retention Program"). In September 2016, the NSUARB approved HGL's Customer Retention Program 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 Customer Retention Program 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 Customer Retention Program to increase the rates that were previously reduced as part of the Customer Retention Program, which has partially restored the rates to previously approved cost of service levels. HGL estimates that the Customer Retention Program will be in place until the end of 2020.

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 cap 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 10,000 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 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 PPA expiring in 2034 with escalation factor of 50 percent of 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 PPAs, fully indexed to BC CPI. The PPA for Forrest Kerr and Volcano Creek expire in 2074 and the PPA 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 2019 to 2023 time period, ACI expects to achieve approximately 5 percent compound annual normalized net income growth from the adjusted normalized net income of $40.5 million achieved in 2018 (see reconciliation under the section *Non-GAAP Measures - Adjusted Normalized Net Income* of this MD&A). Over this period, ACI expects to spend approximately $330 million at its utilities through investments in system betterment projects to maintain the safety and reliability of its utility infrastructure, new business opportunities and technology improvements. ACI expects these investments will grow its rate base to over $1 billion and expects to fund this capital program utilizing internally generated cash flow and a small amount of incremental debt.

In 2019, ACI expects growth in adjusted normalized net income to be driven primarily by additions to rate base at the utilities, normal weather and stronger expected results from ACI's renewable power assets, partially offset by higher expected income tax expense. ACI expects capital spend to be in the range of $75 to $85 million. The expected capital spend also includes approximately $10 million for the Etzikom Lateral Project.

SELECTED FINANCIAL INFORMATION

The following tables summarize key financial results:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Revenue	**95.3**	88.4	**309.1**	309.2
Normalized EBITDA(1)	**33.3**	33.8	**101.6**	104.3
Operating income	**27.2**	27.1	**76.0**	75.2
Net income after taxes	**20.8**	17.1	**45.3**	41.7
Normalized net income(1)	**20.0**	16.6	**41.8**	42.5
Total assets	**1,515.5**	1,611.8	**1,515.5**	1,611.8
Total long-term liabilities	**815.4**	585.4	**815.4**	585.4
Net additions to property, plant and equipment	**24.7**	27.9	**68.2**	58.0
Dividends declared(2)	**5.2**	—	**5.2**	—
Cash from operations	**26.4**	17.7	**89.9**	65.8
Normalized funds from operations(1)	**28.6**	22.6	**88.1**	63.2

	Three Months Ended December 31		Year Ended December 31	
($ per Common Share, except Common Shares outstanding)	**2018**	2017	**2018**	2017
Net income after taxes per Common Share - basic	**0.69**	0.57	**1.51**	1.39
Net income after taxes per Common Share - diluted	**0.69**	0.57	**1.51**	1.39
Normalized net income - basic(1)	**0.67**	0.55	**1.39**	1.42
Dividends declared(2)	**0.1744**	—	**0.1744**	—
Cash from operations	**0.88**	0.59	**3.00**	2.19
Normalized funds from operations(1)	**0.95**	0.75	**2.94**	2.11
Weighted average number of Common Shares outstanding - basic (millions)(3)	**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) Dividend declared per Common Share after the completion of the IPO for the period from October 25, 2018 to December 31, 2018.

(3) 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.

Three Months Ended December 31

Net income after taxes for the three months ended December 31, 2018 was $20.8 million, an increase of $3.7 million compared to the same period in 2017. The increase was due to the same factors as the increase in normalized net income discussed below coupled with a higher unrealized gain on foreign exchange contracts.

Normalized net income for the three months ended December 31, 2018 was $20.0 million, an increase of $3.4 million relative to the same period in 2017 mainly due to lower income tax expense, partially offset by higher interest expense and the same factors as the decrease in normalized EBITDA discussed below.

Operating income for the three months ended December 31, 2018 was $27.2 million, an increase of $0.1 million relative to the same period in 2017 primarily due to a higher unrealized gain on foreign exchange contracts, lower depreciation and amortization expense, partially offset by the same factors as the decrease in normalized EBITDA as discussed below.

Normalized EBITDA for the three months ended December 31, 2018 was $33.3 million, a decrease of $0.5 million relative to the same period in 2017 primarily due to lower generation volume at the Bear Mountain Wind Park and the Northwest Hydro Facilities, higher operating and administrative expenses, warmer weather in Alberta, partially offset by rate base growth at the utilities and colder weather in Nova Scotia.

Operating and administrative expense for the three months ended December 31, 2018 was $23.7 million, an increase of $0.9 million from the same period in 2017 mainly due to an increase in pension expense as a result of lower discount rate, higher wages and salaries as a result of filling vacant positions, and higher contractor and consultant expenses.

Depreciation and amortization expense for the three months ended December 31, 2018 was $6.9 million, a decrease of $0.2 million from the same period in 2017 mainly due to lower depreciation rates per the depreciation study completed at PNG in 2018.

Interest expense for the three months ended December 31, 2018 was $7.6 million compared to $6.7 million in the same period in 2017. The increase of $0.9 million was mainly due to incremental debt issued to capitalize the standalone ACI business.

Income tax recovery for the three months ended December 31, 2018 was $1.3 million, compared to income tax expense of $3.3 million in the same period in 2017 primarily due to the transition of ACI to a standalone entity, a Part VI.1 tax expense that was allocated to PNG by AltaGas in 2017 which was not present in 2018, and lower taxable earnings from the renewable energy assets.

Normalized funds from operations for the three months ended December 31, 2018 was $28.6 million, an increase of $6.0 million relative to the same period in 2017, primarily due to a $4.2 million distribution from Coast LP in the fourth quarter of 2018.

Year Ended December 31

Net income after taxes for the year ended December 31, 2018 was $45.3 million, an increase of $3.6 million from the same period in 2017 driven by a one-time revenue of approximately $1.8 million related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods, an unrealized gain on foreign exchange contracts compared to a loss in the prior year, partially offset by the same factors as the decrease in normalized net income discussed below.

Normalized net income for the year ended December 31, 2018 was $41.8 million, a decrease of $0.7 million relative to the same period in 2017, primarily due to an increase in interest expense, depreciation and amortization expense, and the same factors that resulted in a decrease in normalized EBITDA discussed below, partially offset by lower income tax expense.

Operating income for the year ended December 31, 2018 was $76.0 million, an increase of $0.8 million compared to the same period in 2017, primarily due to a one-time revenue of approximately $1.8 million related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods and an unrealized gain on foreign exchange contracts compared to a loss in the prior year, partially offset by higher depreciation and amortization expense and the same factors as the decrease in normalized EBITDA as discussed below.

Normalized EBITDA for the year ended December 31, 2018 was $101.6 million, a decrease of $2.7 million relative to the same period in 2017, primarily due to lower generation at the Bear Mountain Wind Park and the Northwest Hydro Facilities and higher operating and administrative expenses, partially offset by rate base growth at all the utilities, and colder weather in Alberta and Nova Scotia resulting in higher natural gas consumption.

Operating and administrative expense for the year ended December 31, 2018 was $92.5 million, an increase of $4.2 million from the same period in 2017 mainly due to higher wages and salaries as a result of filling vacant positions, higher pension costs, higher consulting fees, and normal course inflation on costs.

Depreciation and amortization expense for the year ended December 31, 2018 was $28.9 million, an increase of $0.7 million from the same period in 2017 primarily due to an increase in property, plant and equipment, partially offset by lower depreciation rates per the depreciation study completed at PNG in 2018.

Interest expense for the year ended December 31, 2018 was $28.5 million compared to $26.4 million in the same period in 2017. The increase of $2.1 million was mainly due to incremental debt issued to capitalize the standalone ACI business.

Income tax expense for the year ended December 31, 2018 was $2.2 million, a decrease of $4.9 million compared to the same period in 2017, primarily due to the transition of ACI to a standalone entity, a Part VI.1 tax expense that was allocated to PNG by AltaGas in 2017 which was not present in 2018, a one-time non-taxable revenue of approximately $1.8 million received in connection with Part VI.1 tax transfers occurring from earlier periods, and lower taxable earnings from the renewable energy assets.

Normalized funds from operations for the year ended December 31, 2018 was $88.1 million, an increase of $24.9 million relative to the same period in 2017, primarily due to a $24.8 million distribution from Coast LP in 2018, of which $20.6 million was distributed to AltaGas prior to the Acquisition.

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]

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Utilities	**$ 29.7**	$ 28.7	**$ 87.8**	$ 85.9
Renewable Energy	**3.8**	5.1	**14.0**	18.4
Corporate	**(0.2)**	—	**(0.2)**	—
	$ 33.3	$ 33.8	**$ 101.6**	$ 104.3

(1) Non-GAAP financial measure; see discussion in the "*'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)	**2018**	2017	**2018**	2017
Utilities	**$ 25.4**	$ 23.8	**$ 69.5**	$ 64.0
Renewable Energy	**2.0**	3.3	**6.8**	11.2
Corporate	**(0.2)**	—	**(0.3)**	—
	$ 27.2	$ 27.1	**$ 76.0**	$ 75.2

UTILITIES SEGMENT REVIEW

Financial results

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Revenue[1]	**$ 90.6**	$ 82.9	**$ 292.2**	$ 291.8
Cost of sales	**(38.4)**	(32.6)	**(117.1)**	(121.9)
Operating and administrative expense	**(22.5)**	(21.4)	**(87.1)**	(83.1)
Income from equity investment	**0.1**	0.1	**—**	—
Other loss	**(0.1)**	(0.3)	**(0.2)**	(0.9)
Normalized EBITDA[2]	**$ 29.7**	$ 28.7	**$ 87.8**	$ 85.9
Unrealized gain (loss) on foreign exchange contracts	**0.8**	0.5	**1.7**	(0.8)
Depreciation and amortization expense	**(5.1)**	(5.3)	**(21.7)**	(21.0)
Accretion expense	**—**	(0.1)	**(0.1)**	(0.1)
Part VI.1 revenue from AltaGas	**—**	—	**1.8**	—
Operating income	**$ 25.4**	$ 23.8	**$ 69.5**	$ 64.0

(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.

Operating statistics

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Natural gas deliveries - end-use (PJ)	**11.1**	10.8	**34.3**	33.2
Natural gas deliveries - transportation (PJ)	**1.4**	0.9	**5.7**	6.3
Degree day variance from normal - AUI (%) (1)	**(4.3)**	4.0	**6.7**	(1.1)
Degree day variance from normal - HGL (%) (1)	**12.8**	(4.6)	**0.8**	(3.7)

(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	**2018**	2017
Average approved ROE (%)(1)	**9.6**	9.6
Rate base ($ millions)(2)	**886**	834

(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.

Three Months Ended December 31

Revenue increased by $7.7 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to rate base growth, colder weather in Nova Scotia, and higher flow through of gas supply costs to customers, partially offset by warmer weather in Alberta.

Normalized EBITDA increased by $1.0 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to higher revenue discussed above, partially offset by higher cost of gas, higher wages and salaries as a result of filling vacant positions, higher pension costs, and higher consulting fees.

Operating income increased by $1.6 million for the three months ended December 31, 2018 compared to the same period in 2017, primarily due to the same factors as the increase in normalized EBITDA discussed above, lower depreciation and amortization expense as a result of lower depreciation rates per the depreciation study completed in 2018 at PNG, and higher unrealized gain on foreign exchange contracts.

Year Ended December 31

Revenue increased by $2.2 million for the year ended December 31, 2018 compared to the same period in 2017 primarily due to rate base growth at all utilities, colder weather in Alberta and Nova Scotia, and a one-time revenue of approximately $1.8 million related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods. These increases were partially offset by lower cost of service requirements in 2018 at PNG and lower flow through of gas supply costs to customers.

Normalized EBITDA increased by $1.9 million for the year ended December 31, 2018 compared to the prior year, primarily due to rate base growth at all utilities, colder weather in Alberta and Nova Scotia, partially offset by higher operating and administrative expenses primarily due to higher wages and salaries from filling vacant positions, higher pension costs, higher consulting fees and normal course inflation on costs.

Operating income increased by $5.5 million for the year ended December 31, 2018 compared to the prior year, due to the same factors as the increase in normalized EBITDA discussed above, a one-time revenue of approximately $1.8 million related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods, and an unrealized gain on foreign exchange contracts compared to a loss in the prior year, partially offset by higher depreciation and amortization expense due to additions to property, plant, and equipment.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

($ millions)	Three Months Ended December 31				Year Ended December 31			
		2018		2017		**2018**		2017
Revenue	**$**	**4.8**	$	5.4	**$**	**15.2**	$	17.4
Cost of sales		**—**		(0.1)		**(0.2)**		(0.3)
Operating and administrative expense		**(1.0)**		(1.4)		**(5.2)**		(5.2)
Income from equity investment		**—**		1.2		**4.2**		6.5
Normalized EBITDA[(1)]	**$**	**3.8**	$	5.1	**$**	**14.0**	$	18.4
Depreciation and amortization expense		**(1.8)**		(1.8)		**(7.2)**		(7.2)
Operating income	**$**	**2.0**	$	3.3	**$**	**6.8**	$	11.2

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

Operating statistics

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Bear Mountain Wind Park power sold (GWh)	**42.2**	53.3	**143.7**	169.3
Northwest Hydro Facilities power sold (GWh)[(1)]	**10.5**	17.2	**101.4**	115.1

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

Three Months Ended December 31

Revenue decreased by $0.6 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to lower wind generation at the Bear Mountain Wind Park.

Normalized EBITDA decreased by $1.3 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to lower wind generation at the Bear Mountain Wind Park and lower river flow at the Northwest Hydro Facilities as a result of unseasonably cool and dry weather in the fourth quarter of 2018 resulting in a lower equity income pickup.

Operating income decreased by $1.3 million for the three months ended December 31, 2018 compared to the same period in 2017 due to the same factors as the decrease in normalized EBITDA discussed above.

For the year ended December 31

Revenue decreased by $2.2 million for the year ended December 31, 2018 compared to the same period in 2017 primarily due to lower wind generation at the Bear Mountain Wind Park.

Normalized EBITDA decreased by $4.4 million for the year ended December 31, 2018 compared to the same period in 2017 due to lower wind generation at the Bear Mountain Wind Park and lower equity income pick-up from the investment in the Northwest Hydro Facilities. Equity income from the Northwest Hydro Facilities decreased by $2.3 million primarily as a result of lower river flow and increase in operating costs from higher repairs and maintenance work at Forrest Kerr.

Operating income decreased by $4.4 million for the year ended December 31, 2018 compared to the prior year due to the same factors discussed above for normalized EBITDA.

CORPORATE SEGMENT REVIEW

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Operating and administrative expense	**$ (0.3)**	$ —	**$ (0.3)**	$ —
Other income	**0.1**	—	**0.1**	—
Normalized EBITDA[1]	**$ (0.2)**	$ —	**$ (0.2)**	$ —
Foreign exchange loss	**—**	—	**(0.1)**	—
Operating loss	**$ (0.2)**	$ —	**$ (0.3)**	$ —

(1) 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, 2018, operating loss was $0.2 million and $0.3 million, respectively. The increase was mainly due to operating and administrative expense as a result of the Company becoming a standalone entity subsequent to the completion of the Acquisition.

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, 2017 to the quarter ended December 31, 2018.

($ millions, except per Common Share amounts)	**Q4-18**	Q3-18	Q2-18	Q1-18
Revenue	**95.3**	44.1	59.9	109.8
Normalized EBITDA[2]	**33.3**	14.1	18.4	35.8
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**	—	—	—

($ millions, except per Common Share amounts)	Q4-17	Q3-17	Q2-17	Q1-17
Revenue	88.4	45.5	59.5	115.8
Normalized EBITDA[2]	33.8	16.5	17.3	36.7
Net income after taxes	17.1	1.9	3.5	19.2
Net income after taxes per Common Share - basic and diluted ($)[3]	0.57	0.06	0.12	0.64
Dividends declared per Common Share ($)	—	—	—	—

(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 the beginning of each period, including the periods prior to the Acquisition.
(4) Dividends declared per common share after the completion of IPO 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.

Other significant item(s) that impacted quarter-over-quarter revenue during the periods noted include:

- A one-time revenue of approximately $1.8 million recorded in the third quarter of 2018 related to the receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring from earlier periods.

Net income after taxes is also 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 (loss) applicable to common shares during the periods noted was impacted by:

- Higher interest expense during the first three quarters of 2018 as a result of a $30 million debenture issuance to AltaGas in October 2017;
- Higher interest expense during the fourth quarter of 2018 as a result of incremental borrowing to capitalize ACI as a standalone business; and
- Lower income tax expense during the fourth quarter of 2018 as a result of the transition of ACI to a standalone entity.

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		**2018**		2017
($ millions)				
Cash from operations	**$**	**89.9**	$	65.8
Cash used in investing activities		**(76.2)**		(58.2)
Cash used in financing activities		**(11.9)**		(7.6)
Increase in cash and cash equivalents	**$**	**1.8**	$	—

Cash from operations

During the year ended December 31, 2018, cash from operations increased by $24.1 million as compared to the same period in 2017 primarily due to higher cash earnings and a distribution of $24.8 million received from the equity investment in the Northwest Hydro Facilities in 2018**,** partially offset by unfavourable variance to changes in operating assets and liabilities. The unfavourable variance to changes in operating assets and liabilities were mainly due to an increase in payments of supplier invoices. Of the $24.8 million of distribution received from the equity investment in the Northwest Hydro Facilities in 2018, approximately $20.6 million was distributed to AltaGas prior the completion of the Acquisition as part of ACI's financing activities described below.

Investing activities

During the year ended December 31, 2018, cash used in investing activities increased by $18.0 million as compared to the same period in 2017 primarily due to higher capital spending on system betterment and growth.

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

Financing activities

During the year ended December 31, 2018, cash used in financing activities increased by $4.3 million as compared to the same period in 2017 primarily due the repayment of related party debt and advances in connection with the Acquisition and IPO and distributions to AltaGas prior to the completion of the Acquisition, partially offset by the net proceeds received from the IPO and the Over-Allotment Option, the issuance of MTNs, and borrowings from ACI's syndicated term loan and credit facility.

Working Capital

($ millions except current ratio)		December 31, 2018		December 31, 2017
Current assets	**$**	**74.7**	$	201.0
Current liabilities		**91.5**		222.3
Working capital deficiency	**$**	**(16.8)**	$	(21.3)
Working capital ratio		**0.82**		0.90

The variation in the working capital ratio was primarily due to the settlement of the balances due to and from AltaGas and its affiliates as part of the transactions in connection with the Acquisition and the IPO, partially offset by an increase in regulatory liabilities. 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. Its capital resources comprise 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, 2018		December 31, 2017
Short-term debt	**$**	**5.8**	$	9.1
Short-term advances due to related party		**—**		69.8
Current portion of long-term debt		**1.0**		8.0
Current portion of long-term debt due to related parties		**—**		55.0
Long-term debt(1)		**638.8**		25.8
Long-term debt due to related parties		**—**		385.2
Total debt		**645.6**		552.9
Less: cash and cash equivalents		**(1.8)**		—
Net debt	**$**	**643.8**	$	552.9
Shareholders' equity		**608.6**		804.1
Total capitalization	**$**	**1,252.4**	$	1,357.0
Net debt-to-total capitalization (%)		**51.4**		40.7

(1) Net of debt issuance costs of $2.5 million as of December 31, 2018 (December 31, 2017 - $0.2 million).

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. In addition, the Company also entered into a $200 million unsecured syndicated revolving credit facility and a $250 million unsecured syndicated term loan on October 25, 2018 as discussed under the "*Credit Facilities*" section below.

As at December 31, 2018, ACI's total debt primarily consisted of outstanding MTNs of $300 million (2017 - $nil), PNG debentures of $26.0 million (2017 - $34.0 million), unsecured syndicated term loan of $250 million (2017 - $nil), and $72.8 million drawn under other bank credit facilities (2017 - $71.3 million). In addition, ACI had $7.7 million of letters of credit issued (2017 - $7.2 million letters of credit issued and outstanding by AltaGas on behalf of the Company and its subsidiaries).

As at December 31, 2018, ACI's total market capitalization was approximately $486.6 million based on 30,000,000 Common Shares outstanding and a closing trading price on December 31, 2018 of $16.22 per Common Share.

ACI's earnings interest coverage for the rolling 12 months ended December 31, 2018 was 2.7 times (12 months ended December 31, 2017 – 2.8 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, 2018**	Drawn at December 31, 2017
Syndicated revolving credit facility(1)	**$ 200.0**	**$ 48.0**	$ —
Syndicated term loan(2)	**250.0**	**250.0**	—
Operating credit facility(3)	**35.0**	**4.0**	—
PNG committed credit facility(4)	**25.0**	**19.0**	—
PNG operating credit facility(5)	**25.0**	**9.5**	12.8
AltaGas intercompany credit facility(6)	**—**	**—**	55.0
AUGI demand operating facility(7)	**—**	**—**	3.5
	$ 535.0	**$ 330.5**	$ 71.3

(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. Borrowings options under the facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on the credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company credit rating. There are no mandatory repayments prior to maturity. The facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has been in compliance with all financial covenants each quarter since the establishment of the 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 remains fully drawn. Proceeds were used to repay a portion of the Purchase Price Short-Term Note. Borrowings options under the term loan include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on the 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. The term loan has covenants customary for these types of facilities, which must be met at each quarter end. The Company has been in compliance with all financial covenants each quarter since the establishment of the 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 the facility are due on demand. Borrowings options under the facility include overdraft, letters of credit, Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on the credit facility bear fees and interest at rates relevant to the nature of the draw made and the Company credit rating. The facility is used to fund overdraft amounts and to issue letters of credit. At December 31, 2018 a total of $4.0 million (2017 - $nil) in letters of credit have been issued and are outstanding. The facility has covenants customary for these types of facilities, which must be met at each quarter end. The Company has been in compliance with all financial covenants each quarter since the establishment of the facility.

(4) On May 4, 2018, PNG completed the financing of $55 million of revolving five-year credit facilities, $30 million with AltaGas and $25 million with a Canadian chartered bank, that mature on May 4, 2023. The $30 million AltaGas intercompany term loan was acquired by the Company in connection with the Acquisition. The 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 facility has 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 the facility.

(5) On May 4, 2018, the $25 million PNG operating credit facility with a Canadian chartered bank was extended to November 4, 2019. 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, 2018, $3.7 million (2017 - $3.7 million) of letters of credit were outstanding under this facility.

(6) On May 4, 2018, PNG converted its $70 million intercompany revolving 5-year credit facility with AltaGas into a 4.15 percent $55 million intercompany term loan that matures on December 2, 2027. The AltaGas intercompany term loan was acquired by the Company in connection with the Acquisition.

(7) The $20 million AUGI unsecured, uncommitted, demand revolving operating credit facility with a Canadian chartered bank was cancelled effective October 25, 2018.

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, 2018**
Bank debt-to-capitalization(1)(2)	not greater than 65 percent	54%
Bank EBITDA-to-interest expense(1)(2)	not less than 2.5x	3.6x

(1) Calculated in accordance with the Company's credit facility agreement, which is 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, 2018, approximately $700 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 October 25, 2018, DBRS Limited ("DBRS") provided the Company an Issuer Credit Rating of BBB (high) with a Stable trend. On December 6, 2018, DBRS finalized a rating of BBB (high) with a Stable trend on the Company's $300 million MTNs.

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. ACI provides an annual fee to DBRS for credit rating services.

CONTRACTUAL OBLIGATIONS

December 31, 2018					Payments Due by Period
($ millions)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Accounts payable and accrued liabilities	$ 64.9	$ 64.9	$ —	$ —	$ —
Short-term debt(1)	5.8	5.8	—	—	—
Long-term debt(1)	642.3	1.0	251.4	68.9	321.0
Operating leases(2)	10.8	1.5	2.3	0.8	6.2
Purchase obligations(3)	328.4	42.8	36.7	35.4	213.5
Pension plan and retiree benefits(4)	6.9	6.9	—	—	—
Service agreement(5)	6.0	2.0	4.0	—	—
Total contractual obligations	$ 1,065.1	$ 124.9	$ 294.4	$ 105.1	$ 540.7

(1) Excludes interest payments and deferred financing costs.

(2) Operating 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 2019 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 2019. Contributions are made in exchange 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 $6.0 million over the next three years.

INVESTED CAPITAL

($ millions)	Three Months Ended December 31, 2018			Three Months Ended December 31, 2017		
	Renewable Energy	**Utilities**	**Total**	Renewable Energy	Utilities	Total
Invested capital:						
PP&E[(1)]	**$ —**	**$ 24.7**	**$ 24.7**	$ —	$ 28.1	$ 28.1
Intangible assets	**—**	**1.2**	**1.2**	—	0.6	0.6
Invested capital	**—**	**25.9**	**25.9**	—	28.7	28.7
Disposals:						
PP&E	**—**	**—**	**—**	—	(0.2)	(0.2)
Net invested capital	**$ —**	**$ 25.9**	**$ 25.9**	$ —	$ 28.5	$ 28.5

(1) Excludes $0.4 million of capitalized operating, maintenance and administrative expenses which have been deferred in regulatory assets as allowed by the Customer Retention Program for the three months ended December 31, 2018 (2017 - $0.7 million).

($ millions)	Year Ended December 31, 2018			Year Ended December 31, 2017		
	Renewable Energy	**Utilities**	**Total**	Renewable Energy	Utilities	Total
Invested capital:						
PP&E[(1)]	**$ —**	**$ 68.5**	**$ 68.5**	$ —	$ 58.7	$ 58.7
Intangible assets	**—**	**3.2**	**3.2**	—	0.6	0.6
Invested capital	**—**	**71.7**	**71.7**	—	59.3	59.3
Disposals:						
PP&E	**—**	**(0.3)**	**(0.3)**	—	(0.7)	(0.7)
Net invested capital	**$ —**	**$ 71.4**	**$ 71.4**	$ —	$ 58.6	$ 58.6

(1) Excludes $2.4 million of capitalized operating, maintenance and administrative expenses which have been deferred in regulatory assets as allowed by the Customer Retention Program for the year ended December 31, 2018 (2017 - $2.9 million).

Invested capital for the three months and year ended December 31, 2018 was $25.9 million and $71.7 million, respectively, the majority of which relates to system betterment, replacement of transmission and distribution lines and new business installations.

Of the total capital expenditures of $71.7 million during 2018, PNG incurred approximately $4.0 million on the construction of a pipeline to facilitate the supply of product to a propane export terminal on Ridley Island near Prince Rupert, British Columbia and approximately $1.8 million (net of insurance proceeds) on the permanent repair for a washout of a pipeline at Copper River in British Columbia.

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 of ACI 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 Heritage Gas' 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, 2018 and December 31, 2017 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 strong access to capital.

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 PPA 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 and support ready access to capital markets. 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 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 Company's 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
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 • Customer retention program in place at HGL to mitigate fuel switching
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
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.	• PPAs 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
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. The inability to attract, develop and retain skilled workforces 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
Cybersecurity	
Security breaches of the Company's information technology infrastructure, including, without limitation, cyber-attacks and cyberterrorism, 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.	• Continuous monitoring of the Company's infrastructure, technologies and data • Ongoing cybersecurity communications and training to staff • Conducting third-party vulnerability and cybersecurity tests • Corporate threat detection and incident response protocols
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 under the terms of the transitional service agreement with AltaGas

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 will provide certain administrative services required by the Company, to include: (a) general administrative and corporate services, including 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; (b) credit support services; and (c) accounting, budgeting and engineering services in respect of the Ikhil Joint Venture. AltaGas will provide 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.

In the normal course of business, ACI also transacts with its subsidiaries. Refer to note 22 of the Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classifications of revenue, income, and expenses in the Consolidated Statements of Income.

SHARE INFORMATION

	As at March 6, 2019
Issued and outstanding	
Common shares	30,000,000
Issued	
Share options	212,263
Share options exercisable	—

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, 2018 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.

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 2018 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, 2018, 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.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2018, the Company adopted the following FASB issued Accounting Standards Updates ("ASU"):

- ASU No. 2014-09 "Revenue from Contracts with Customers" and all related amendments (collectively "ASC 606"). The Company adopted ASC 606 using the modified retrospective method to contracts that have not been completed as at January 1, 2018. Under the modified retrospective method, the comparative information is not adjusted. Therefore, results reported for 2018 reflect the application of ASC 606 while the results for 2017 reflect previous revenue recognition guidance under ASC 605. Under ASC 605, revenue was recognized when the risk and rewards were transferred to the customer and collectability was reasonably assured. Under ASC 606, revenue is recognized as the Company satisfies its performance obligations through the transfer of promised goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The adoption of ASC 606 impacted the timing of revenue recognition in relation to contracts with take-or-pay or minimum volume commitments whereby the customers have make up rights for deficiency quantities. However, on adoption, no cumulative adjustments to opening retained earnings were required for this change in revenue recognition pattern as none of the customers had material deficiency quantities. Please also refer to note 14 in the consolidated financial statements. The application of ASC 606 did not have a material impact on the Company's consolidated financial statements in 2018;

- ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revised an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amended certain disclosure requirements associated with the fair value of financial instruments. The provisions of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-15 "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments". The amendments in this ASU clarified the classification of certain cash flow transactions on the statement of cash flow. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-16 "Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory". The amendments in this ASU revised the accounting for income tax consequences on intra-entity transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-18 "Statement of Cash Flows: Restricted Cash". The amendments in this ASU required those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-01 "Company Combinations: Clarifying the Definition of a Company". The amendments in this ASU changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The Company will apply the amendments to this ASU prospectively;

- ASU No. 2017-04 "Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment". The amendments in this ASU removed the second step of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-05 "Other Income – Gains and Losses from the De-recognition of Nonfinancial Assets: Clarifying the Scope of Asset De-recognition Guidance and Accounting for Partial Sales of Nonfinancial Assets". The amendments in this ASU clarified the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-07 "Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The amendments in this ASU revised the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limited the components that are eligible for capitalization in assets to only the service cost component. The Company applied the change in presentation of the current service cost and other components of net benefit cost on the income statement retrospectively. As a result, $0.9 million of net benefit cost associated with other components were reclassified from the line item "Operating and administrative" to "Other loss" on the Consolidated Statement of Income for the year ended December 31, 2017. The Company applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-09 "Compensation – Stock Compensation: Scope of Modifications Accounting". The amendments in this ASU provided guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The guidance was applied prospectively and did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-12 "Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities". The amendments in this ASU improved the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and made certain targeted improvements to simplify the application of hedge accounting. The Company early adopted this ASU. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements; and

- ASU No. 2018-03 "Technical Corrections and Improvements to Financial Instruments – Overall". The amendments in this ASU clarified certain aspects of the guidance issued in ASU No. 2016-01. The Company early adopted this ASU. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In February 2016, FASB issued ASU No. 2016-02 "Leases", which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. In January 2018, FASB issued ASU 2018-01 "Land Easement Practical Expedient for Transition to Topic 842", providing entities with an optional election not to evaluate existing and expired land easements not previously accounted for as leases under ASC 840 using the provisions of ASC 842. In July 2018, FASB issued ASU 2018-11 "Targeted Improvements", allowing entities to report the comparative periods presented in the period of adoption under the old lease standard (ASC 840), and recognize a cumulative-effect adjustment to the opening balance of retained earnings as of January 1, 2019. The ASU also provides a practical expedient under which lessors are not required to separate out lease and non-lease components of a contract, provided certain conditions are met. In December 2018, FASB issued ASU 2018-20 "Narrow-Scope Improvement for Lessors", allowing lessors to include and exclude certain costs from variable payments. The ASU also require lessors to allocate certain variable payments to the lease and non-lease components when the changes in facts and circumstances on which the variable payment is based occur. The amendments to the new leases standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company is in the final stages of evaluating the impact of adopting ASC 842 on its consolidated financial statements. Leases, except as noted below, for which the Company is the lessee will be reflected on the balance sheet upon adoption by recording an increase to long-term assets and an increase to long-term liabilities net of the current portion that is recorded in current liabilities. The increases are expected to be less than 1 percent of total assets. In addition, the Company currently expects to utilize the transition practical expedients which allow entities to not have to reassess whether an arrangement contains a lease under the provisions of ASC 842, as well as the transition practical expedients related to land easements and not separating out lease and non-lease components of a contract for certain classes of assets.

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. 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. In November 2018, FASB issued ASU No. 2018-19 "Codification Improvements to Topic 326 – Financial Instruments: Credit Losses". The amendments in the ASU clarify that operating lease receivable are not in the scope of ASC 326-20 and should be accounted for under ASC 842. The effective date for the amendments in this ASU is the same as the effective date in ASU No. 2016-13. The Company is currently completing its assessment of the impact of this ASU on its consolidated financial statements.

In June 2018, FASB issued 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 amendments in this ASU are effective for fiscal years beginning after December 15, 2018, 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. 2018-13 "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 August 2018, FASB issued ASU No. 2018-15 "Intangibles-Goodwill and Other – Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement (CCA) 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. 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 clarify the following guidance around collaborative arrangements. A collaborative arrangement, as defined by the guidance in Topic 808, is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. Collaborative arrangements within the scope of ASC 808 are not typically conducted through a separate legal entity and if they are it would be accounted for under ASC 810. 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.

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 purchase, deliver, and store 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.

DISCLOSURE CONTROLS AND PROCEDURES ("DCP") AND INTERNAL CONTROL OVER FINANCIAL REPORTING ("ICFR")

Because the Company became a reporting issuer on October 18, 2018, it is eligible to file the alternative form of annual certificates (Form 52-109F1 IPO/RTP) for the year ended December 31, 2018 under National Instrument 52-109 – *Certification of Disclosure in Issuer's Annual and Interim Filings* ("NI 52-109").

Under this alternative certificate~~s~~, management is responsible for reviewing the Company's annual information form, Consolidated Financial Statements, and this MD&A. Management has ensured that based on their knowledge, using reasonable diligence, the annual filings do not contain any untrue statement or omission of material fact required to be stated or that is necessary to make a statement not misleading, for the period covered by the annual filings. Management has ensured that based on their knowledge, using reasonable diligence, the Consolidated Financial Statements fairly present in all material respects the financial condition, financial performance and cash flows of the company as of the date of and for the periods presented in the annual filings, and that financial statements prepared for external purposes are in accordance with U.S. GAAP.

Consistent with NI 52-109, management will evaluate the design and effectiveness of ICFR and DCP for the first time as at December 31, 2019.

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

($ millions, except where noted)	**2018**	2017	2016
Revenue	**309.1**	309.2	312.6
Net income after taxes	**45.3**	41.7	37.0
Net income after taxes per Common Share - Basic ($ per Common Share)[(1)]	**1.51**	1.39	1.23
Net income after taxes per Common Share - Diluted ($ per Common Share)[(1)]	**1.51**	1.39	1.23
Total assets	**1,515.5**	1,611.8	1,522.8
Total long-term financial liabilities	**641.3**	411.2	408.2
Weighted average number of Common Shares outstanding (millions)[(1)]	**30.0**	30.0	30.0
Dividends declared per Common Share ($ per share)[(2)]	**0.1744**	—	—

(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.

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, adjusted 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

($ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Year Ended December 31 2018	Year Ended December 31 2017
Normalized EBITDA	**$ 33.3**	$ 33.8	**$ 101.6**	$ 104.3
Add (deduct):				
Foreign exchange loss	**—**	—	**(0.1)**	—
Unrealized gain (loss) on foreign exchange contracts	**0.8**	0.5	**1.7**	(0.8)
Accretion expenses	**—**	(0.1)	**(0.1)**	(0.1)
Part VI.1 revenue from AltaGas	**—**	—	**1.8**	—
Operating income before depreciation and amortization expense	**34.1**	34.2	**104.9**	103.4
Depreciation and amortization expense	**(6.9)**	(7.1)	**(28.9)**	(28.2)
Operating income	**$ 27.2**	$ 27.1	**$ 76.0**	$ 75.2

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

($ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Year Ended December 31 2018	Year Ended December 31 2017
Normalized net income	**$ 20.0**	$ 16.6	**$ 41.8**	$ 42.5
Add (deduct) after-tax:				
Unrealized gain (loss) on foreign exchange contracts	**0.8**	0.5	**1.7**	(0.8)
Part VI.1 revenue from AltaGas	**—**	—	**1.8**	—
Net income after taxes	**$ 20.8**	$ 17.1	**$ 45.3**	$ 41.7

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

($ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Year Ended December 31 2018	Year Ended December 31 2017
Normalized funds from operations	**$ 28.6**	$ 22.6	**$ 88.1**	$ 63.2
Add (deduct):				
Part VI.1 revenue from AltaGas	**—**	—	**1.8**	—
Net change in operating assets and liabilities	**(2.2)**	(4.9)	**—**	2.6
Cash from operations	**$ 26.4**	$ 17.7	**$ 89.9**	$ 65.8

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 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.

Adjusted Normalized Net Income

The following table sets forth the Company's estimates of its normalized net income and net income after taxes for the year ended December 31, 2018 assuming the Acquisition had been completed and the IPO had been closed at the beginning of the period. The Company's assumptions in preparing the estimates are set out in the notes below the table. Although many of the adjustments are estimates and are not objectively determinable, the Company believes that the amounts represent reasonable estimates of its normalized net income and net income after taxes for the year ended December 31, 2018 based on the assumptions made. The Company believes adjusted normalized net income and net income after taxes is useful to investors and analysts when trying to determine what the results of operations for 2018 would have been if it was under the Company's capital structure going forward.

For the 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 gain on foreign exchange contracts	(1.7)	—	(1.7)
Part VI.1 revenue from AltaGas	(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 the Company as if they had occurred at the beginning of the period. Please refer to the *Capital Resources* section of this MD&A for the capital structure subsequent to the Acquisition 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 this MD&A.

The foregoing table may be considered a financial outlook, but is not a forecast or projection of future results. The actual consolidated results of operations of the Company, including the businesses underlying the assets acquired as part of the Acquisition, for any period will likely vary from the amounts set forth in the foregoing table, and such variations may be material. See "*Cautionary Statement Regarding Forward-Looking Information*" section of this MD&A for a discussion of the risks that could cause actual results to vary.

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

Independent Auditors' 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, 2018 and 2017, and the consolidated statements of income and comprehensive income, consolidated statements of changes in equity and consolidated statements of 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, 2018 and 2017, 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
- Annual Report

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 6, 2019

Consolidated Balance Sheets

As at *($ millions)*	**December 31, 2018**	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	**$ 1.8**	$ —
Accounts receivable, net of allowances *(note 16)*	**64.4**	62.0
Inventory *(note 4)*	**1.4**	1.7
Due from related party *(note 22)*	**—**	134.2
Regulatory assets *(note 8)*	**0.6**	0.8
Foreign exchange contracts asset *(note 16)*	**1.4**	—
Prepaid expenses and other current assets	**5.1**	2.3
	74.7	201.0
Property, plant and equipment *(note 5)*	**968.6**	933.5
Intangible assets *(note 6)*	**17.5**	16.4
Goodwill *(note 7)*	**119.1**	119.1
Regulatory assets *(note 8)*	**215.8**	202.2
Other long-term assets *(note 19)*	**0.9**	—
Investments accounted for by the equity method *(note 9)*	**118.9**	139.6
	$ 1,515.5	$ 1,611.8
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 16)*	**64.9**	66.1
Short-term advances due to related party *(notes 16 and 22)*	**—**	69.8
Short-term debt *(notes 10 and 16)*	**5.8**	9.1
Current portion of long-term debt *(notes 11 and 16)*	**1.0**	8.0
Current portion of long-term debt due to related parties *(notes 16 and 22)*	**—**	55.0
Customer deposits	**10.9**	9.8
Regulatory liabilities *(note 8)*	**8.9**	4.2
Foreign exchange contracts liability *(note 16)*	**—**	0.3
	91.5	222.3
Long-term debt *(notes 11 and 16)*	**638.8**	25.8
Long-term debt due to related parties *(notes 16 and 22)*	**—**	385.2
Asset retirement obligations *(note 12)*	**1.8**	1.2
Deferred income taxes *(note 15)*	**122.6**	121.6
Regulatory liabilities *(note 8)*	**22.1**	22.0
Future employee obligations *(note 19)*	**30.1**	29.6
	$ 906.9	$ 807.7

As at *($ millions)*	**December 31, 2018**	December 31, 2017
Shareholders' equity		
Common shares, no par value, unlimited shares authorized;		
2018 - 30,000,000 shares issued and outstanding *(note 17)*	**321.0**	—
Net parental investment	**—**	804.7
Contributed surplus	**100.0**	—
Retained earnings	**188.0**	—
Accumulated other comprehensive loss *(note 13)*	**(0.4)**	(0.6)
	608.6	804.1
	$ 1,515.5	$ 1,611.8

Commitments and contingencies *(note 20)*
Subsequent events *(note 25)*

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

Year ended December 31 ($ millions)		**2018**		2017
REVENUE *(note 14)*		**309.1**		309.2
EXPENSES				
Cost of sales, exclusive of items shown separately		**117.3**		122.2
Operating and administrative		**92.5**		88.3
Accretion *(note 12)*		**0.1**		0.1
Depreciation and amortization *(notes 5 and 6)*		**28.9**		28.2
		238.8		238.8
Income from equity investments *(note 9)*		**4.2**		6.5
Unrealized gain (loss) on foreign exchange contracts *(note 16)*		**1.7**		(0.8)
Other loss		**(0.1)**		(0.9)
Foreign exchange loss		**(0.1)**		—
Operating income		**76.0**		75.2
Interest expense				
Short-term debt		**(3.3)**		(0.6)
Long-term debt		**(25.2)**		(25.8)
Income before income taxes		**47.5**		48.8
Income tax expense (recovery) *(note 15)*				
Current		**3.5**		7.1
Deferred		**(1.3)**		—
Net income after taxes	**$**	**45.3**	$	41.7
Net income per common share *(note 18)*				
Basic		**1.51**	**$**	1.39
Diluted		**1.51**	**$**	1.39

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Comprehensive Income

Year ended December 31 ($ millions)		**2018**		2017
Net income after taxes	**$**	**45.3**	$	41.7
Other comprehensive income (loss) (OCI), net of taxes				
Actuarial gain (loss) on pension and post-retirement benefit plans *(note 13)*		**0.2**		(0.1)
Total OCI, net of taxes		**0.2**		(0.1)
Comprehensive income, net of taxes	**$**	**45.5**	$	41.6

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Equity

Year ended December 31 ($ millions)		2018		2017
Common shares *(note 17)*				
Balance, beginning of year	**$**	**—**	$	—
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**	$	—
Net parental investment *(notes 1 and 21)*				
Balance, beginning of year	**$**	**804.7**	$	742.0
Net income after taxes		**28.8**		41.7
Distributions to AltaGas Ltd. prior to the Acquisition		**(114.7)**		21.0
Transactions in connection with the Acquisition		**(383.7)**		—
Recapitalization by AltaGas Ltd.		**(335.1)**		—
Balance, end of year	**$**	**—**	$	804.7
Contributed surplus *(note 1)*				
Balance, beginning of year	**$**	**—**	$	—
Recapitalization by AltaGas Ltd.		**100.0**		—
Balance, end of year	**$**	**100.0**	$	—
Retained earnings				
Balance, beginning of year	**$**	**—**	$	—
Recapitalization by AltaGas Ltd.		**176.7**		—
Net income after taxes		**16.5**		—
Common share dividends		**(5.2)**		—
Balance, end of year	**$**	**188.0**	$	—
Accumulated other comprehensive loss *(note 13)*				
Balance, beginning of year	**$**	**(0.6)**	$	(0.5)
Other comprehensive income (loss)		**0.2**		(0.1)
Balance, end of year	**$**	**(0.4)**	$	(0.6)
Total shareholders' equity	**$**	**608.6**	$	804.1

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

Year ended December 31 ($ millions)		**2018**		2017
Cash from operations				
Net income after taxes	**$**	**45.3**	$	41.7
Items not involving cash:				
Depreciation and amortization expense *(notes 5 and 6)*		**28.9**		28.2
Accretion expense *(note 12)*		**0.1**		0.1
Deferred income tax recovery *(note 15)*		**(1.3)**		—
Income from equity investments *(note 9)*		**(4.2)**		(6.5)
Unrealized loss (gain) on foreign exchange contracts *(note 16)*		**(1.7)**		0.8
Other		**(2.0)**		(1.1)
Net distributions from equity investments		**24.8**		—
Changes in operating assets and liabilities *(note 23)*		**—**		2.6
	$	**89.9**	$	65.8
Investing activities				
Acquisition of property, plant and equipment		**(73.2)**		(58.2)
Acquisition of intangible assets		**(3.3)**		(0.7)
Proceeds from disposition of assets, net of transaction costs		**0.3**		0.7
	$	**(76.2)**	$	(58.2)
Financing activities				
Net issuance (repayment) of amounts due to (from) related parties		**134.2**		(39.0)
Issuance (repayment) of short-term debt		**(3.3)**		3.0
Net issuance of banker's acceptances		**316.3**		—
Issuance of long-term debt, net of debt issuance costs		**297.7**		—
Repayment of long-term debt due to related parties		**(28.4)**		(30.0)
Repayment of notes issued to AltaGas Ltd.		**(858.9)**		—
Repayment of long-term debt		**(8.0)**		(9.4)
Net proceeds on issuance of common shares		**258.4**		—
Contributions from (distributions to) AltaGas Ltd. prior to the Acquisition		**(114.7)**		1.8
Common share dividends		**(5.2)**		—
Issuance of long-term debt due to related parties		**—**		66.0
	$	**(11.9)**	$	(7.6)
Change in cash and cash equivalents		**1.8**		—
Cash and cash equivalents, beginning of year		**—**		—
Cash and cash equivalents, end of year	**$**	**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* 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, 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.

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. The Company repaid in full $34.0 million to AltaGas on November 21, 2018.

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. Contingent rentals are recorded when the condition that created the present obligation to make such payments occurs 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 Alberta Utilities Commission ("AUC"), the British Columbia Utilities Commission ("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 8 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	4 - 70 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 are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to the Company are accounted for as capital leases.

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 - 9 years
Land rights	5 - 60 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 post-retirement benefit plans is 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.

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.

Allocation of Corporate Costs

Allocated costs include AltaGas charges including, but not limited to: finance, accounting and tax, legal and compliance, office services and corporate resources, information technology, procurement and other administrative functions. Charges for allocated costs are included in operating and administrative expenses in the Consolidated Statements of Income. Prior to October 18, 2018, costs were allocated to the Company based on a combination of several factors including 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. Subsequent to October 18, 2018, costs were charged by AltaGas to the Company pursuant to the Transition Services Agreement described in note 22.

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 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, 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, 2018, the Company adopted the following Financial Accounting Standards Board ("FASB") issued Accounting Standards Updates ("ASU"):

- ASU No. 2014-09 "Revenue from Contracts with Customers" and all related amendments (collectively "ASC 606"). The Company adopted ASC 606 using the modified retrospective method to contracts that have not been completed as at January 1, 2018. Under the modified retrospective method, the comparative information is not adjusted. Therefore, results reported for 2018 reflect the application of ASC 606 while the results for 2017 reflect previous revenue recognition guidance under ASC 605. Under ASC 605, revenue was recognized when the risk and rewards were transferred to the customer and collectability was reasonably assured. Under ASC 606, revenue is recognized as the Company satisfies its performance obligations through the transfer of promised goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The adoption of ASC 606 impacted the timing of revenue recognition in relation to contracts with take-or-pay or minimum volume commitments whereby the customers have make up rights for deficiency quantities. However, on adoption, no cumulative adjustments to opening retained earnings were required for this change in revenue recognition pattern as none of the customers had material deficiency quantities. Please also refer to note 14 for further details. The application of ASC 606 did not have a material impact on the Company's consolidated financial statements in 2018;

- ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revised an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amended certain disclosure requirements associated with the fair value of financial instruments. The provisions of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-15 "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments". The amendments in this ASU clarified the classification of certain cash flow transactions on the statement of cash flow. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-16 "Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory". The amendments in this ASU revised the accounting for income tax consequences on intra-entity transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2016-18 "Statement of Cash Flows: Restricted Cash". The amendments in this ASU required those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements;

- ASU No. 2017-01 “Company Combinations: Clarifying the Definition of a Company”. The amendments in this ASU changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The Company will apply the amendments to this ASU prospectively;

- ASU No. 2017-04 “Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment”. The amendments in this ASU removed the second step of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. The adoption of this ASU did not have a material impact on the Company’s consolidated financial statements;

- ASU No. 2017-05 “Other Income – Gains and Losses from the De-recognition of Nonfinancial Assets: Clarifying the Scope of Asset De-recognition Guidance and Accounting for Partial Sales of Nonfinancial Assets”. The amendments in this ASU clarified the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The adoption of this ASU did not have a material impact on the Company’s consolidated financial statements;

- ASU No. 2017-07 “Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost”. The amendments in this ASU revised the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limited the components that are eligible for capitalization in assets to only the service cost component. The Company applied the change in presentation of the current service cost and other components of net benefit cost on the income statement retrospectively. As a result, $0.9 million of net benefit cost associated with other components were reclassified from the line item “Operating and administrative” to “Other loss” on the Consolidated Statement of Income for the year ended December 31, 2017. The Company applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on the Company’s consolidated financial statements;

- ASU No. 2017-09 “Compensation – Stock Compensation: Scope of Modifications Accounting”. The amendments in this ASU provided guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The guidance was applied prospectively and did not have a material impact on the Company’s consolidated financial statements;

- ASU No. 2017-12 “Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities”. The amendments in this ASU improved the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and made certain targeted improvements to simplify the application of hedge accounting. The Company early adopted this ASU. The adoption of this ASU did not have a material impact on the Company’s consolidated financial statements; and

- ASU No. 2018-03 “Technical Corrections and Improvements to Financial Instruments – Overall”. The amendments in this ASU clarified certain aspects of the guidance issued in ASU No. 2016-01. The Company early adopted this ASU. The adoption of this ASU did not have a material impact on the Company’s consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In February 2016, FASB issued ASU No. 2016-02 “Leases”, which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. In January 2018, FASB issued ASU 2018-01 “Land Easement Practical Expedient for Transition to Topic 842”, providing entities with an optional election not to evaluate existing and expired land easements not previously accounted for as leases under ASC 840 using the provisions of ASC 842. In July 2018, FASB issued ASU 2018-11 “Targeted Improvements”, allowing entities to report the comparative periods presented in the period of adoption under the old lease standard (ASC 840), and recognize a cumulative-effect adjustment to the opening balance of retained earnings as of January 1, 2019. The ASU also provides a practical expedient under which lessors are not required to separate out lease and non-lease components of a contract, provided certain conditions are met. In December 2018, FASB issued ASU 2018-20 “Narrow-Scope Improvement for Lessors”, allowing lessors to include and exclude certain costs from variable payments. The ASU also require lessors to allocate certain variable payments to the lease and non-lease components when the changes in facts and circumstances on which the variable payment is based occur. The amendments to the new leases standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company is in the final stages of evaluating the impact of adopting ASC 842 on its consolidated financial statements. Leases, except as noted below, for which the Company is the lessee will be reflected on the balance sheet upon adoption by recording an increase to long-term assets and an increase to long-term liabilities net of the current portion that is recorded in current liabilities. The increases are expected to be less than 1 percent of total assets. In addition, the Company currently expects to utilize the transition practical expedients which allow entities to not have to reassess whether an arrangement contains a lease under the provisions of ASC 842, as well as the transition practical expedients related to land easements and not separating out lease and non-lease components of a contract for certain classes of assets.

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. 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. In November 2018, FASB issued ASU No. 2018-19 “Codification Improvements to Topic 326 – Financial Instruments: Credit Losses”. The amendments in the ASU clarify that operating lease receivable are not in the scope of ASC 326-20 and should be accounted for under ASC 842. The effective date for the amendments in this ASU is the same as the effective date in ASU No. 2016-13. The Company is currently completing its assessment of the impact of this ASU on its consolidated financial statements.

In June 2018, FASB issued 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 amendments in this ASU are effective for fiscal years beginning after December 15, 2018, 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. 2018-13 “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 August 2018, FASB issued ASU No. 2018-15 “Intangibles-Goodwill and Other – Internal-Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement (CCA) 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. 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 clarify the following guidance around collaborative arrangements. A collaborative arrangement, as defined by the guidance in Topic 808, is a contractual arrangement under which two or more parties actively participate in a joint operating activity and are exposed to significant risks and rewards that depend on the activity's commercial success. Collaborative arrangements within the scope of ASC 808 are not typically conducted through a separate legal entity and if they are it would be accounted for under ASC 810. 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.

4. INVENTORY

As at		**December 31, 2018**		December 31, 2017
Natural gas	**$**	**0.8**	$	1.1
Other inventory		**0.6**		0.6
	$	**1.4**	$	1.7

5. PROPERTY, PLANT AND EQUIPMENT

As at		**December 31, 2018**										
										December 31, 2017		
		Cost		**Accumulated amortization**		**Net book value**		Cost		Accumulated amortization		Net book value
Renewable Energy	**$**	**211.0**	**$**	**(63.9)**	**$**	**147.1**	$	211.0	$	(56.8)	$	154.2
Utilities		**941.3**		**(119.8)**		**821.5**		882.0		(102.7)		779.3
	$	**1,152.3**	**$**	**(183.7)**	**$**	**968.6**	$	1,093.0	$	(159.5)	$	933.5

Contributions in aid of construction of $4.3 million (2017 - $0.5 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, 2018 was $25.7 million (2017 - $24.3 million).

As at December 31, 2018, the Company had approximately $13.3 million (December 31, 2017 - $8.6 million) of capital projects under construction that were not yet subject to amortization.

In addition, $9.2 million of land costs as at December 31, 2018 (December 31, 2017 - $9.0 million) were not subject to amortization.

6. INTANGIBLE ASSETS

As at		**December 31, 2018**			December 31, 2017	
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Software	**$ 29.0**	**$ (19.7)**	**$ 9.3**	$ 25.9	$ (17.7)	$ 8.2
Land rights	**9.2**	**(2.3)**	**6.9**	9.0	(2.2)	6.8
Franchises and consents	**3.6**	**(2.3)**	**1.3**	3.6	(2.2)	1.4
	$ 41.8	**$ (24.3)**	**$ 17.5**	$ 38.5	$ (22.1)	$ 16.4

Amortization expense related to intangible assets for the year ended December 31, 2018 was $2.6 million (2017 - $3.4 million).

As at December 31, 2018, the Company excluded $1.9 million (December 31, 2017 - $1.8 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:

2019	$ 2.7
2020	$ 2.8
2021	$ 2.5
2022	$ 0.9
2023	$ 0.6
Thereafter	$ 6.1

7. GOODWILL

As at	**December 31, 2018**	December 31, 2017
Balance, beginning of year	**$ 119.1**	$ 119.1
Balance, end of year	**$ 119.1**	$ 119.1

8. 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, 2018 and 2017 and the remaining period over which the Company expects to realize the assets or settle the liabilities:

As at	**December 31, 2018**	December 31, 2017	Recovery Period
Regulatory assets - current			
Deferred cost of gas	**$ 0.1**	$ 0.5	Less than one year
Deferred property taxes	**0.5**	0.3	Less than one year
	$ 0.6	$ 0.8	
Regulatory assets - non-current			
Deferred regulatory costs and rate stabilization adjustment	**$ 2.5**	$ 2.4	1 - 10 years
Pipeline rehabilitation costs	**—**	0.3	1 - 3 years
Future recovery of pension and other retirement benefits [a]	**30.2**	31.4	Various
Deferred depreciation and amortization [b]	**22.6**	23.3	Various
Deferred future income taxes [c]	**103.9**	95.3	Various
Deferred customer retention program amortization [d]	**26.2**	16.5	Various
Revenue deficiency account [e]	**28.0**	31.0	Various
Other	**2.4**	2.0	Various
	$ 215.8	$ 202.2	
Regulatory liabilities - current			
Deferred cost of gas	**$ 7.3**	$ 4.2	Less than one year
Deferred regulatory costs	**1.4**	—	Less than one year
Other	**0.2**	—	Less than one year
	$ 8.9	$ 4.2	
Regulatory liabilities - non-current			
Option fees deferral [f]	**$ 4.5**	$ 4.3	Various
Future removal and site restoration costs [g]	**17.5**	17.0	Various
Other	**0.1**	0.7	Various
	$ 22.1	$ 22.0	

(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 certain commercial and residential customers, 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 cap 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.

9. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Description	Location	Ownership Percentage	December 31, 2018	December 31, 2017
Inuvik Gas Ltd.	Canada	33.333	**$ —**	$ —
Coast LP	Canada	10	**118.9**	139.6
			$ 118.9	$ 139.6

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

Year ended December 31	2018	2017
Revenues	**$ 111.4**	$ 131.0
Expenses	**(68.4)**	(66.7)
	$ 43.0	$ 64.3

As at	December 31, 2018	December 31, 2017
Current assets	**$ 15.1**	$ 235.0
Property, plant and equipment	**$ 1,089.8**	$ 1,088.0
Intangible assets	**$ 246.3**	$ 249.5
Current liabilities	**$ (24.7)**	$ (33.0)
Other long-term liabilities	**$ (137.4)**	$ (142.8)

During the year ended December 31, 2018, a distribution of $24.8 million was received from Coast LP that occurred concurrently with a change in ownership of that entity. Of the $24.8 million received, $20.6 million was distributed to AltaGas prior to the Acquisition.

10. SHORT-TERM DEBT

As at December 31, 2018, the Company held a $35.0 million (December 31, 2017 - $nil) 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. Letters of credit outstanding under this facility as at December 31, 2018 were $4.0 million (December 31, 2017 - $nil).

As at December 31, 2018, the Company held a $25.0 million bank operating facility which is available for PNG's working capital purposes and expires on November 4, 2019. 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, 2018, prime-rate advances under the operating facility were $5.8 million (December 31, 2017 - $9.1 million). Letters of credit outstanding under this facility as at December 31, 2018 were $3.7 million (December 31, 2017 - $3.7 million).

As at December 31, 2017, the Company held a $20.0 million unsecured, uncommitted demand operating credit facility with a Canadian chartered bank. Draws on this facility were by way of prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2017 were $3.5 million. This facility was cancelled effective October 25, 2018.

11. LONG-TERM DEBT

As at	Maturity date	December 31, 2018	December 31, 2017
Credit facilities			
$200 million unsecured revolving credit facility[(a)]	25-Oct-2022	**$ 47.9**	$ —
$25 million PNG committed credit facility[(a)]	4-May-2023	**19.0**	—
Debenture notes			
PNG 2018 series debenture - 8.75 percent[(b)]	15-Nov-2018	**—**	7.0
PNG 2025 series debenture - 9.30 percent[(b)]	18-Jul-2025	**12.5**	13.0
PNG 2027 series debenture - 6.90 percent[(b)]	2-Dec-2027	**13.5**	14.0
Unsecured term loan[(c)]	25-Oct-2020	**249.4**	—
Medium term notes			
$300 million senior unsecured - 4.26 percent[(d)]	5-Dec-2028	**300.0**	—
		$ 642.3	$ 34.0
Less debt issuance costs		**(2.5)**	(0.2)
		$ 639.8	$ 33.8
Less current portion		**(1.0)**	(8.0)
		$ 638.8	$ 25.8

(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) The proceeds of the term loan were used to partially repay the Purchase Price Short-Term Note.

(d) *The proceeds of the medium term notes issued on December 5, 2018 were used to partially repay the Purchase Price Long-Term Note.*

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

As at	
2019	$ 1.0
2020	$ 250.4
2021	$ 1.0
2022	$ 48.9
2023	$ 20.0
Thereafter	$ 321.0
	$ 642.3

12. ASSET RETIREMENT OBLIGATIONS

As at	December 31, 2018	December 31, 2017
Balance, beginning of year	**$ 1.2**	$ 1.2
Revision in estimated cash flow	**0.5**	(0.1)
Accretion expense	**0.1**	0.1
Balance, end of year	**$ 1.8**	$ 1.2

The Company estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2018 was $7.9 million (December 31, 2017 - $7.9 million).

Asset retirement obligations have been recorded in the consolidated financial statements at estimated values discounted at rates between 4.6 and 8.0 percent and are expected to be incurred between 2021 and 2075. No assets have been legally restricted for settlement of the estimated liability.

13. ACCUMULATED OTHER COMPREHENSIVE LOSS

($ millions)		Defined benefit pension and PRB plans
Opening balance, January 1, 2018	$	**(0.6)**
OCI before reclassification		**0.3**
Amounts reclassified from OCI		**—**
Current period OCI (pre-tax)		**0.3**
Income tax on amounts retained in AOCI		**(0.1)**
Income tax on amounts reclassified to earnings		**—**
Net current period OCI		**0.2**
Ending balance, December 31, 2018		**(0.4)**
Opening balance, January 1, 2017	$	(0.5)
OCI before reclassification		(0.2)
Amounts reclassified from OCI		—
Current period OCI (pre-tax)		(0.2)
Income tax on amounts retained in AOCI		0.1
Income tax on amounts reclassified to earnings		—
Net current period OCI		(0.1)
Ending balance, December 31, 2017		(0.6)

14. REVENUE

The following table disaggregates revenue by major sources:

	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	**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.

The carrying value of PP&E associated with leasing revenue was $147.1 million as at December 31, 2018 (December 31, 2017 - $154.2 million). For the year ended December 31, 2018, the total revenue earned from contingent rentals was $15.2 million (2017 - $15.5 million).

Accounts receivable as at December 31, 2018 include unbilled receivables of $15.7 million (December 31, 2017 - $22.2 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, 2018:

	2019	2020	2021	2022	2023	> 2023	Total
Gas sales and transportation services	$ 237.2	$ 234.8	$ 163.5	$ 60.9	$ 29.3	$ 218.1	**$ 943.8**

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	2018	2017
Income before income taxes	**$ 47.5**	$ 48.8
Statutory income tax rate (%)	**27.0**	27.0
Expected taxes at statutory rates	**$ 12.8**	$ 13.2
Add (deduct) the tax effect of:		
Permanent differences between accounting and tax basis of assets and liabilities	**(3.7)**	—
Rate adjustments to enacted Canadian rates	**0.5**	0.4
Current tax impact of Part VI.1 tax liability transferred from AltaGas to PNG	**—**	0.5
Change in valuation allowance	**1.2**	
Other	**(0.3)**	0.4
Deferred income tax recovery on regulated assets	**(8.3)**	(7.4)
Income tax provision	**$ 2.2**	$ 7.1
Current	**$ 3.5**	$ 7.1
Deferred	**(1.3)**	—
	$ 2.2	$ 7.1
Effective income tax rate (%)	**4.6**	14.5

Net deferred income tax liabilities comprise of the following:

As at	December 31, 2018	December 31, 2017
PP&E and intangible assets	**$ 72.8**	$ 110.2
Equity investments	**36.2**	—
Regulatory assets	**44.6**	44.1
Deferred compensation	**(7.8)**	(7.5)
Non-capital losses	**(24.2)**	(24.4)
Tax pools	**(3.0)**	—
Valuation allowance	**3.8**	—
Other	**0.2**	(0.8)
	$ 122.6	$ 121.6

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, 2018, the Company had tax-effected non-capital losses of approximately $24.2 million (December 31, 2017 - $24.4 million), which expire between 2035 and 2038.

As at December 31, 2018 and 2017, 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, due from related party, foreign exchange contracts, accounts payable and accrued liabilities, short-term debt, short-term advances due to related party, current portion of long-term debt, long-term debt and long-term debt due to related parties.

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, due from related party, 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, 2018
	Carrying Amount	Level 1	Level 2	Level 3	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

					December 31, 2017
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	0.3	—	0.3	—	0.3
Amortized cost					
Current portion of long-term debt [(a)]	8.0	—	8.5	—	8.5
Current portion of long-term debt due to related parties	55.0	—	54.1	—	54.1
Long-term debt [(a)]	25.8	—	31.5	—	31.5
Long-term debt due to related parties	385.2	—	395.8	—	395.8
	$ 474.3	$ —	$ 490.2	$ —	$ 490.2

(a) Excludes deferred financing costs

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, 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. As at December 31, 2017, the Company had outstanding foreign exchange forward contracts for US$31.6 million at an average rate of $1.26 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 power 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, 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**

As at December 31, 2017		Total		AR accruals		Receivables impaired		Less than 30 days		31 to 60 days		61 to 90 days		Over 90 days
Trade receivable	$	54.6	$	22.2	$	1.0	$	29.4	$	1.6	$	0.2	$	0.2
Other		8.4		—		—		8.4		—		—		—
Allowance for credit losses		(1.0)		—		(1.0)		—		—		—		—
	$	62.0	$	22.2	$	—	$	37.8	$	1.6	$	0.2	$	0.2

Allowance for credit losses		**December 31, 2018**		December 31, 2017
Balance, beginning of year	**$**	**1.0**	$	1.0
New allowance		**0.4**		0.3
Recovery of allowance		**0.2**		—
Allowance applied to uncollectible customer accounts		**(0.5)**		(0.3)
Balance, end of year	**$**	**1.1**	$	1.0

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 and support ready access to capital markets.

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

				Payments due by period						
As at December 31, 2018		**Total**		**Less than 1 year**		**1-3 years**		**4-5 years**		**After 5 years**
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

As at December 31, 2017		Total		Less than 1 year		1-3 years		4-5 years		After 5 years
										Payments due by period
Accounts payable and accrued liabilities	$	66.1	$	66.1	$	—	$	—	$	—
Short-term advances due to related party		69.8		69.8		—		—		—
Current portion of long-term debt due to related parties		55.0		55.0		—		—		—
Short-term debt		9.1		9.1		—		—		—
Foreign exchange contracts liability		0.3		0.3		—		—		—
Current portion of long-term debt [(a)]		8.0		8.0		—		—		—
Long-term debt [(a)]		26.0		—		2.0		2.0		22.0
Long-term debt due to related parties		385.2		—		205.2		—		180.0
	$	619.5	$	208.3	$	207.2	$	2.0	$	202.0

(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, 2017 and December 31, 2017	143,140,001		—
Consolidation of common shares on a 28:1 basis	(138,027,858)		—
Shares issued to AltaGas in connection with the Acquisition (note 1)	5,912,857		58.4
Shares issued on public offering, net of issuance costs (after tax) (note 1)	16,500,000		228.1
Shares issued pursuant to the Over-Allotment Option (after tax) (note 1)	2,475,000		34.5
As at December 31, 2018	**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, 2018, 1,299,625 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, 2018, the unexpensed fair value of share option compensation cost associated with future periods was $0.3 million (December 31, 2017 - $nil).

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

As at		**December 31, 2018**
	Number of options	**Exercise price**
Share options outstanding, beginning of year	**—**	**$ —**
Granted	**200,375**	**14.65**
Share options outstanding, end of year	**200,375**	**$ 14.65**
Share options exercisable, end of year	**—**	**$ —**

As at December 31, 2018, the aggregate intrinsic value of the total options exercisable was $nil and the total intrinsic value of options outstanding was $0.3 million.

The following table summarizes employee share options outstanding and exercisable as at December 31, 2018:

	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	6.0	—	$ —	—
	200,375	**$ 14.65**	**6.0**	**—**	**$ —**	**—**

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	**2018**
Fair value per option ($)	**1.61**
Risk-free interest rate (%)	**2.2**
Expected life (years)	**6.0**
Expected volatility (%)	**25.2**
Annual dividend yield (%)	**6.4**
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	**2018**	2017
(number of units)		
Balance, beginning of year	**—**	—
Granted	**92,502**	—
Outstanding, end of year	**92,502**	—

For the year ended December 31, 2018, the compensation expense recorded for the MTIP and DSUP was $0.1 million (2017 - $nil). As at December 31, 2018, the unrecognized compensation expense relating to the remaining vesting period for the MTIP was $1.4 million (December 31, 2017 - $nil) and is expected to be recognized over the vesting period.

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 each period presented.

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

Year ended December 31		**2018**		2017
Numerator:				
Net income after taxes	**$**	**45.3**	$	41.7
Denominator *(millions)*:				
Weighted average number of common shares outstanding - basic		**30.0**		30.0
Dilutive equity instruments		**—**		—
Weighted average number of common shares outstanding - diluted		**30.0**		30.0
Basic net income per common share	**$**	**1.51**	$	1.39
Diluted net income per common share	**$**	**1.51**	$	1.39

For the year ended December 31, 2018, no share options (2017 – 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 $0.4 million for the year ended December 31, 2018 (2017 - $0.3 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 required to be completed as of a date no later than 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, 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)**

Year ended December 31, 2017	Defined Benefit	Post-Retirement Benefits	Total
Accrued benefit obligation			
Balance, beginning of year	$ 104.8	$ 14.1	$ 118.9
Actuarial loss (gain)	6.6	(1.8)	4.8
Current service cost	5.4	0.6	6.0
Member contributions	0.1	—	0.1
Interest cost	4.1	0.6	4.7
Benefits paid	(3.6)	(0.3)	(3.9)
Expenses paid	(0.2)	—	(0.2)
Balance, end of year	$ 117.2	$ 13.2	$ 130.4
Plan assets			
Fair value, beginning of year	$ 81.8	$ 7.0	$ 88.8
Actual return on plan assets	6.9	0.4	7.3
Employer contributions	7.5	1.2	8.7
Member contributions	0.1	—	0.1
Benefits paid	(3.6)	(0.3)	(3.9)
Expenses paid	(0.2)	—	(0.2)
Fair value, end of year	$ 92.5	$ 8.3	$ 100.8
Net amount recognized	$ (24.7)	$ (4.9)	$ (29.6)

The following amounts were included in the Consolidated Balance Sheet:

	December 31, 2018			December 31, 2017		
(in millions of Canadian dollars)	**Defined Benefit**	**Post-Retirement Benefits**	**Total**	Defined Benefit	Post-Retirement Benefits	Total
Other long-term assets	**$ —**	**$ 0.4**	**$ 0.4**	$ —	$ —	$ —
Future employee obligations	**(25.3)**	**(4.8)**	**(30.1)**	(24.7)	(4.9)	(29.6)
	$ (25.3)	**$ (4.4)**	**$ (29.7)**	$ (24.7)	$ (4.9)	$ (29.6)

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

	December 31, 2018	December 31, 2017
Accumulated benefit obligation [a]	**$ (101.5)**	$ (101.8)
Fair value of plan assets	**91.9**	92.5
Funded status	**$ (9.6)**	$ (9.3)

(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, 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)**

Year ended December 31, 2017	Defined Benefit	Post-Retirement Benefits	Total
Net actuarial loss	$ (0.3)	$ (0.5)	$ (0.8)
Recognized in AOCI pre-tax	$ (0.3)	$ (0.5)	$ (0.8)
Increase by the amount included in deferred tax liabilities	0.1	0.1	0.2
Net amount in AOCI after-tax	$ (0.2)	$ (0.4)	$ (0.6)

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, 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 net actuarial loss [b]	**—**	**—**	**—**
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.*

Year ended December 31, 2017	Defined Benefit	Post-Retirement Benefits	Total
Current service cost [a]	$ 5.4	$ 0.6	$ 6.0
Interest cost [b]	4.1	0.6	4.7
Expected return on plan assets [b]	(5.0)	(0.2)	(5.2)
Amortization of regulatory asset [b]	1.3	0.1	1.4
Net benefit cost recognized	$ 5.8	$ 1.1	$ 6.9

(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, 2018:

	Fair value	Level 1	Level 2	Level 3	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ **5.5**	$ 5.5	$ —	$ —	5.5
Canadian equities	**31.3**	31.3	—	—	31.1
Foreign equities	**15.3**	15.3	—	—	15.2
Fixed income	**42.7**	42.7	—	—	42.4
Real estate	**5.9**	—	5.9	—	5.8
	$ **100.7**	$ 94.8	$ 5.9	$ —	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	**2018**		2017	
Discount rate (%)	**2.80 - 3.60**	**3.60**	2.65 - 4.00	4.00
Expected long-term rate of return on plan assets (%) [(a)]	**0.00 - 6.20**	**3.10**	6.18	3.10
Rate of compensation increase (%)	**0.00 - 3.25**	**3.25**	3.00 - 3.25	3.25
Average remaining service life of active employees (years)	**14.7**	**14.7**	14.6	14.6

(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	**2018**		2017	
Discount rate (%)	**3.10 - 4.10**	**3.90**	2.80 - 3.60	3.60
Rate of compensation increase (%)	**0.00 - 3.50**	**3.25**	3.00 - 3.25	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 6.3 percent and the ultimate trend rate is 4.0 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 2018:

	Increase	Decrease
Service and interest costs	$ 0.3	$ (0.2)
Accrued benefit obligation	$ 2.2	$ (1.7)

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:		
2019	$ 6.6	$ 0.3
Expected benefit payments:		
2019	$ 4.0	$ 0.3
2020	4.3	0.4
2021	4.5	0.4
2022	4.7	0.4
2023	5.0	0.5
2024-2028	$ 28.4	$ 2.8

20. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

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

Future payments of these commitments at December 31, 2018 are estimated as follows:

	2019	2020	2021	2022	2023	2024 and beyond	**Total**
Gas purchase and transportation [(a)]	$ 42.8	$ 17.0	$ 19.7	$ 19.1	$ 16.3	$ 213.5	**$ 328.4**
Service agreement [(b)]	2.0	2.0	2.0	—	—	—	**6.0**
Operating leases [(c)]	1.5	1.2	1.1	0.6	0.2	6.2	**10.8**
	$ 46.3	$ 20.2	$ 22.8	$ 19.7	$ 16.5	$ 219.7	**$ 345.2**

(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 2019 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 $6 million over the next three years.

(c) Operating leases include lease arrangements for office spaces, land, 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 purchase, deliver, and store 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.

Contingencies
The Company is subject to various legal claims and actions arising in the normal course of 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. PRE-ACQUISITION RELATIONSHIP WITH ALTAGAS

Prior to the Acquisition, IPO and separation of the Company as a stand-alone public entity as discussed under note 1, the Acquired Assets were managed and operated in the normal course of business by AltaGas along with other AltaGas businesses and affiliates, and not as a separate entity. 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 in the Company's consolidated financial statements may not be indicative of the actual expenses that would have been incurred during the periods presented if the Company historically operated as a separate entity. In addition, the expenses reflected in the consolidated financial statements may not be indicative of expenses that will be incurred in the future by the Company.

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).

Transactions with AltaGas pre-acquisition
AltaGas performed cash management and other treasury related functions on a centralized basis for nearly all its operating units, which included the Company. Corporate costs were allocated to the Company based on a combination of several factors including asset values, payroll expenses, and earnings.

- **Cash Management**
  Prior to the IPO, the Company participated in AltaGas' centralized cash management programs. For certain of the Company's operating facilities, cash receipts were received and disbursements made by AltaGas, with any excess cash being retained by AltaGas. For the purpose of these consolidated financial statements, the net cash retained by AltaGas was reflected as "Due from Related Party" at December 31, 2017. Cash retained by AltaGas on behalf of the Company was not kept in specific accounts for the Company and was instead comingled with cash from other AltaGas entities.

- **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 (note that the Company comprises parts of multiple legal entities).

  Prior to October 25, 2018, 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. 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.

- **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 Statements of Income and have a pre-tax total of $7.5 million in 2018 (2017 - $8.5 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.

22. RELATED PARTY TRANSACTIONS AND BALANCES

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 will provide certain day-to-day services required by the Company, to include: (a) general administrative and corporate services, including 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; (b) credit support services; and (c) accounting, budgeting and engineering services in respect of the Ikhil Joint Venture. AltaGas will provide 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 AltaGas and its affiliates, are measured at the exchange amount and are as follows:

As at		**December 31, 2018**		December 31, 2017
Due from related parties				
Accounts receivable [(a)]	**$**	**—**	$	0.3
Due from related party [(b)]		**—**		134.2
Foreign exchange contracts asset - current [(c)]		**0.9**		—
	$	**0.9**	$	134.5
Due to related parties				
Accounts payable [(d)]	**$**	**16.4**	$	28.7
Foreign exchange contracts liability - current [(c)]		**—**		0.3
Short-term advances due to related party[(e)]		**—**		69.8
Current portion of long-term debt due to related parties		**—**		55.0
Long-term debt due to related parties		**—**		385.2
	$	**16.4**	$	539.0

(a) Receivables from affiliates of AltaGas.

(b) Cash balances managed on behalf of the Company by AltaGas.

(c) Foreign exchange hedges with AltaGas.

(d) Payables to AltaGas and affiliates of AltaGas.

(e) Short-term advances due to a related party are payable to AltaGas which are unsecured, non interest-bearing and due on demand. The balance outstanding was acquired by the Company as part of the Acquisition.

Related party transactions

The following transactions with AltaGas and its affiliates are measured at the exchange amount and have been recorded on the Consolidated Statements of Income for the years ended December 31, 2018 and 2017:

Year ended December 31		**2018**		2017
Revenue [(a)]	**$**	**3.9**	$	4.7
Unrealized gain (loss) on foreign exchange contracts with AltaGas	**$**	**1.2**	$	(0.8)
Cost of sales [(b)]	**$**	**(93.2)**	$	(92.4)
Operating and administrative expenses [(c)]	**$**	**(8.6)**	$	(9.0)
Interest expense [(d)]	**$**	**(22.1)**	$	(22.5)

(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 (note 21).

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

Long-Term Debt Due to Related Parties

The Company entered into borrowing agreements with AltaGas and certain of its subsidiaries:

As at	Maturity date	**December 31, 2018**	December 31, 2017
Medium-term notes (MTNs)			
Debenture - 4.14%	1-Jun-2020	**$ —**	$ 20.0
Debenture - 4.48%	15-Mar-2024	**—**	40.0
Debenture - 3.91%	15-Jan-2025	**—**	15.0
Debenture - 3.76%	7-Apr-2026	**—**	10.0
Debenture - 4.20%	7-Apr-2026	**—**	45.0
Debenture - 5.21%	13-Jan-2044	**—**	20.0
Debenture - 4.88%	15-Aug-2044	**—**	20.0
Debenture - 5.03%	4-Oct-2047	**—**	30.0
Shareholder loan [(a)]	1-Jan-2020	**—**	176.0
Revolving loan [(b)]	7-Jun-2018	**—**	55.0
Other related party loan [(c)]	1-Jan-2020	**—**	9.2
		$ —	$ 440.2
Less current portion		**—**	(55.0)
		$ —	$ 385.2

(a) Unsecured loan from AltaGas bearing interest at 7.25%.

(b) $70 million, 5 year revolver due June 7, 2018 with draws available by way of bankers' acceptances bearing interest at the three-month BA rate plus 1.75% and subject to a stand-by fee of 0.35%.

(c) Unsecured loan from AltaGas bearing interest at 6.00%.

Prior to the Acquisition, AUGI repaid $28.4 million of its indebtedness to AltaGas and the remaining balance of long-term debt due to related parties were acquired by the Company as part of the Acquisition.

23. SUPPLEMENTAL CASH FLOW INFORMATION

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

Year ended December 31	**2018**	2017
Source (use) of cash:		
Accounts receivable	**$ 0.6**	$ (7.6)
Inventory	**0.3**	0.2
Other current assets	**(2.8)**	0.9
Regulatory assets (current)	**0.2**	0.1
Accounts payable and accrued liabilities	**(4.5)**	4.6
Customer deposits	**1.1**	1.8
Regulatory liabilities (current)	**4.6**	1.6
Other operating assets and liabilities	**0.5**	1.0
Changes in operating assets and liabilities	**$ —**	$ 2.6

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

Year ended December 31		**2018**		2017
Interest paid	**$**	**23.6**	$	23.5
Income taxes paid (net of refunds)	**$**	**1.4**	$	5.1

24. 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 corporate services, financial and general corporate support and corporate assets.

The following tables show the composition by segment:

	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 contract	**1.7**	**—**	**—**	**—**	**1.7**
Other income (loss)	**(0.2)**	**—**	**0.1**	**—**	**(0.1)**
Foreign exchange loss	**—**	**—**	**(0.1)**	**—**	**(0.1)**
Operating income	**$ 69.5**	**$ 6.8**	**$ (0.3)**	**$ —**	**$ 76.0**
Interest expense	**(23.7)**	**—**	**(4.8)**	**—**	**(28.5)**
Income before income taxes	**$ 45.8**	**$ 6.8**	**$ (5.1)**	**$ —**	**$ 47.5**
Net additions 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.

	Year ended December 31, 2017				
	Utilities	Renewable Energy	Corporate	Intersegment Elimination	Total
Revenue	$ 291.8	$ 17.4	$ —	$ —	$ 309.2
Unrealized loss on foreign exchange contract	(0.8)	—	—	—	(0.8)
Cost of sales	(121.9)	(0.3)	—	—	(122.2)
Operating and administrative	(83.1)	(5.2)	—	—	(88.3)
Accretion expenses	(0.1)	—	—	—	(0.1)
Depreciation and amortization	(21.0)	(7.2)	—	—	(28.2)
Income from equity investments	—	6.5	—	—	6.5
Other loss	(0.9)	—	—	—	(0.9)
Operating income	$ 64.0	$ 11.2	$ —	$ —	$ 75.2
Interest expense	(26.4)	—	—	—	(26.4)
Income before income taxes	$ 37.6	$ 11.2	$ —	$ —	$ 48.8
Net additions to:					
Property, plant and equipment[(a)]	$ 58.0	$ —	$ —	$ —	$ 58.0
Intangible assets	$ 0.6	$ —	$ —	$ —	$ 0.6

(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, 2018				
Goodwill	**$ 119.1**	**$ —**	**$ —**	**$ 119.1**
Segmented assets	**$ 1,244.9**	**$ 274.0**	**$ (3.4)**	**$ 1,515.5**
As at December 31, 2017				
Goodwill	$ 119.1	$ —	$ —	$ 119.1
Segmented assets	$ 1,179.8	$ 297.8	$ 134.2	$ 1,611.8

25. SUBSEQUENT EVENTS

Subsequent events have been reviewed through March 6, 2019, the date on which these consolidated financial statements were approved for issue by the Board of Directors.

CORPORATE INFORMATION

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President and Chief Executive Officer

Shaun Toivanen
Executive Vice President, Chief Financial Officer and Corporate Secretary

Leigh Ann Shoji-Lee
Executive Vice President Utility Operations and President Pacific Northern Gas Ltd.

Mark Lowther
President, AltaGas Utilities Inc.

John Hawkins
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