AltaGas

NEWS RELEASE
ALTAGAS LTD. REPORTS RECORD 2017 FIRST QUARTER RESULTS

Calgary, Alberta (April 26, 2017)

Highlights
(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Achieved record normalized EBITDA[1] of $228 million in the first quarter of 2017, a 28 percent increase compared to the same quarter of 2016;
- Increased normalized funds from operations[1] by approximately 29 percent to $170 million in the first quarter of 2017;
- Announced transformational $8.4 billion pending acquisition of WGL Holdings, Inc. (WGL Acquisition) on January 25, 2017, and submitted regulatory applications to the public utility commissions in Maryland, Virginia and Washington D.C. on April 24, 2017;
- Commenced construction of the 99 Mmcf/d Townsend 2a shallow-cut processing facility and continue to advance discussions with other producers to backstop the second train of Townsend Phase 2;
- Made significant progress on the first train of the North Pine NGL Separation Facility, accelerating the expected in-service date of the facility to the first quarter of 2018; and
- Announced a positive Final Investment Decision (FID) on the Ridley Island Propane Export Terminal on January 3, 2017. Site preparation and pre-construction activities are underway, construction is expected to begin in the second quarter of 2017 and the terminal is being designed to ship 40,000 Bbls/d of propane to global markets off the west coast of Canada.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported that normalized EBITDA in the first quarter of 2017 increased $50 million to $228 million, compared to the same quarter in 2016. Normalized funds from operations were $170 million ($1.01 per share) for the first quarter of 2017, compared to $132 million ($0.90 per share) in the same period of 2016. On a U.S. GAAP basis, net income applicable to common shares for the first quarter of 2017 was $32 million ($0.19 per share) compared to $55 million ($0.38 per share) in the first quarter of 2016. Normalized net income[1] was $65 million ($0.39 per share) for the first quarter of 2017, compared to $38 million ($0.26 per share) in the same period of 2016.

"During the first quarter of 2017, we realized substantial growth in normalized EBITDA and funds from operations, showcasing our diversified and highly contracted asset base and putting us on track to achieve high single digit percentage growth over 2016. We also started construction on over $750 million of strategic projects, including pre-construction activities on our Ridley Island Propane Export Terminal, as part of our northeast B.C. and energy export strategies," said David Harris, President and Chief Executive Officer of AltaGas. “We are also very excited about the pending acquisition of WGL that will provide us with a robust, complementary set of high quality, low-risk, long-lived assets that complement each of our energy segments and greatly increase our scale and diversity. Both companies are working diligently toward closing the acquisition with the submission of the local and federal regulatory filings having been completed on April 24. This marks an important step toward an exciting future with WGL where we expect to have approximately $22 billion in combined assets and over $7 billion of highly attractive organic growth opportunities upon closing.”

The first quarter of 2017 was driven by strong performance across AltaGas’ three business segments. Normalized EBITDA in the quarter increased 28 percent to $228 million as compared to $178 million for the same quarter of 2016. The Gas segment benefitted from the commencement of commercial operations at the Townsend Facility in the third quarter of 2016, higher earnings from Petrogas Energy Corp. (Petrogas) including the dividend income from the Petrogas Preferred Shares, higher revenue from NGL marketing, higher realized frac spreads and processed volumes, and higher natural gas storage margins. Results for the Utilities were positively impacted by colder weather experienced at certain of the Utilities and the interim and refundable rate increases at ENSTAR. The Power segment benefitted from a full quarter of contributions from the Pomona Energy Storage Facility which commenced commercial operations on December 31, 2016, and the absence of equity losses

1. Non-GAAP measure; see discussion in the advisories of this news release

from the Sundance B PPAs. These increases were partially offset by the weaker U.S. dollar on reported results of the U.S. assets.

Normalized funds from operations were $170 million ($1.01 per share) in the first quarter of 2017, up from $132 million ($0.90 per share) in the first quarter of 2016. The increase was driven by the increase in normalized EBITDA, partially offset by higher interest expense and lower common share dividends from Petrogas.

For the first quarter of 2017, AltaGas recorded income tax expense of $21 million compared to $6 million in the same quarter of 2016. The increase was primarily due to the $10 million tax recovery related to the Tidewater Gas Asset Disposition in the first quarter of 2016 and a portion of transaction costs incurred on the pending WGL Acquisition in the first quarter of 2017 not being tax deductible.

On a U.S. GAAP basis, net income applicable to common shares for the first quarter of 2017 was $32 million ($0.19 per share) compared to $55 million ($0.38 per share) for the same quarter in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition and higher income tax, interest, depreciation and amortization expense, partially offset by the previously referenced factors resulting in the increase in normalized EBITDA. In addition, net income per common share decreased for the three months ended March 31, 2017, compared to the same period in 2016, as a result of the same factors impacting net income, as well as a higher number of common shares outstanding in 2017.

Normalized net income was $65 million ($0.39 per share) for the first quarter of 2017, compared to $38 million ($0.26 per share) reported for the same quarter in 2016. The increase was driven by the same factors impacting normalized EBITDA, partially offset by higher income tax, interest, and depreciation and amortization expense. Normalizing items in the first quarter of 2017 included after-tax amounts related to transaction costs on acquisitions, unrealized gains on risk management contracts, loss on sale of assets, and amortization of financing costs associated with the bridge facility. In the first quarter of 2016, normalizing items included after-tax amounts related to transaction costs incurred on acquisitions, unrealized gains on risk management contracts, gains on sale of assets and related tax recovery, provision on investment accounted for by the equity method, and dilution loss recognized on investment accounted for by the equity method.

Pending Acquisition of WGL Holdings, Inc.

On January 25, 2017, AltaGas entered into a definitive agreement to indirectly acquire WGL Holdings, Inc. (WGL). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of US$6.8 billion, including the assumption of approximately US$2.1 billion of debt as at December 31, 2016.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia. WGL has a growing midstream business with investments in natural gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeast United States with capabilities for connections to marine-based energy export opportunities via the North American Atlantic coast through the proposed Cove Point LNG terminal in Maryland being developed by a third party, currently expected to be operational in late 2017. WGL also owns contracted clean power assets, with a focus on distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 260,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

“Our success has been driven by our commitment to clean energy infrastructure assets in Midstream, Power and Utilities, and by maintaining a balance over the long-term in these three segments,” said Harris. “WGL also has significant investments in Midstream, Power and Utilities and is a highly diversified business. This is why WGL is attractive to AltaGas.”

The WGL Acquisition is not subject to any financing contingency. AltaGas expects that cash to close the WGL Acquisition will be provided from a combination of the net proceeds from the $400 million private placement of subscription receipts and the $2.2 billion bought deal subscription receipt offering (including the partially exercised over-allotment option) for total gross proceeds of approximately $2.6 billion, subsequent offerings of senior debt, hybrid securities, equity or equity-linked securities (including Preferred Shares or convertible debentures), selected AltaGas asset sales and through a fully committed approximately US$3.0 billion bridge facility, which would be available for 12 to 18 months following closing of the WGL Acquisition. AltaGas believes there are a number of attractive, actionable opportunities to monetize certain of its assets in a manner which supports the Corporation's long term strategy of growing in attractive areas and maintaining a long term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. The timing of these subsequent offerings and asset sales is subject to prevailing market conditions, but are generally expected to be completed prior to the closing of the WGL Acquisition.

The WGL Acquisition is subject to certain closing conditions, including approval of WGL common shareholders and certain regulatory and government review and/or approvals, including the Public Service Commission of the District of Columbia (PSC of DC), the Maryland Public Service Commission (PSC of MD), the Commonwealth of Virginia State Corporation Commission (SCC of VA), the United States Federal Energy Regulatory Commission (FERC), and the Committee on Foreign Investment in the United States (CFIUS), as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

The special meeting of WGL common shareholders to approve the WGL Acquisition is scheduled for May 10, 2017. In addition, regulatory applications were filed with the PSC of DC, the PSC of MD, the SCC of VA, FERC and CFIUS on April 24, 2017. All decisions are expected to be received in the first half of 2018.

Project Updates

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $600 to $650 million for 2017. AltaGas' Gas segment will account for approximately 65 to 75 percent of total capital expenditures, while AltaGas' Utility segment will account for approximately 20 to 25 percent and the Power segment will account for approximately 5 to 10 percent. Gas and Power maintenance capital is expected to be approximately $25 to $35 million of total capital expenditures in 2017. The majority of AltaGas' capital expenditures relating to its Gas segment will be allocated towards AltaGas' growth projects including the Ridley Island Propane Export Terminal, the first train of Townsend Phase 2, the North Pine Facility, and the North Pine Pipelines.

AltaGas' 2017 committed capital program is expected to be funded through internally-generated cash flow and the Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP). If required, the Corporation also has approximately $1.9 billion available under its credit facilities as at March 31, 2017, as well as access to capital markets.

Townsend Gas Processing Facility Expansion (Townsend Phase 2)

On February 22, 2017, the Board of Directors approved a positive FID for the first train of Townsend Phase 2 (Townsend 2A). Townsend 2A will be a 99 Mmcf/d shallow-cut gas processing facility to be located on the existing Townsend site, adjacent to the currently operating Townsend Facility. The estimated cost of Townsend 2A is expected to be approximately $80 million and with the addition of incremental field compression equipment to move raw gas production from the Blair Creek area to Townsend, the estimated total cost is expected to be approximately $120 to $140 million. NGL produced from Townsend Phase 2 is expected to be transported to AltaGas' North Pine Facility via existing and planned pipelines owned by AltaGas. Fabrication is underway on several components of Townsend 2A as well as on the incremental field compression equipment. Commercial operation for Townsend 2A is expected to begin in October 2017. AltaGas and Painted Pony Petroleum Ltd. (Painted Pony) have entered into 20-year take-or-pay agreements in respect of Townsend 2A and the incremental field compression equipment, subject to the satisfaction of certain conditions contained in the agreements.

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North Pine NGL Project

On October 19, 2016, the Board of Directors approved a positive FID for the construction, ownership and operation of the North Pine Facility to be located approximately 40 km northwest of Fort St. John, British Columbia. The North Pine Facility will be connected to existing AltaGas infrastructure in the region and will have access to the CN rail network, allowing for the transportation of propane from the North Pine Facility to the Ridley Island Propane Export Terminal. AltaGas will be constructing the North Pine Facility with two separate NGL separation trains, each capable of processing up to 10,000 Bbls/d of propane plus NGL mix (C3+), for a total of 20,000 Bbls/d. The first phase will also include 6,000 Bbls/d of condensate (C5+) terminalling capacity, with ultimate capacity for up to 20,000 Bbls/d. The second 10,000 Bbls/d NGL separation train is expected to follow after completion of the first train, subject to sufficient commercial support from area producers.

Two eight inch diameter NGL supply pipelines (the North Pine Pipelines), each approximately 40 km in length, will also be constructed to connect AltaGas' existing Alaska Highway truck terminal (the Truck Terminal) to the North Pine Facility. One supply line will carry C3+ with the other carrying C5+. The existing Townsend NGL Egress Pipelines currently delivering product from AltaGas' Townsend Facility will be connected to the North Pine Pipelines to enable shipment of NGL produced at the Townsend Facility directly to the North Pine Facility via the Truck Terminal. Logging, clearing and mulching activities have been completed and civil construction activities will commence in the second quarter of 2017. The target commercial on-stream date for the North Pine Facility and the North Pine Pipelines is expected in the first quarter of 2018, up from the second quarter of 2018.

The capital cost of the first train and associated pipelines is estimated to be approximately $125 to $135 million. This investment will be backstopped by long-term supply agreements with Painted Pony for a portion of the total capacity, and will include dedication of all of Painted Pony's NGL produced at the Townsend and Blair Creek facilities.

Ridley Island Propane Export Terminal

On January 3, 2017, AltaGas reached a positive FID on the Ridley Island Propane Export Terminal, having received approval from federal regulators. AltaGas has executed long-term agreements securing land tenure along with rail and marine infrastructure on Ridley Island.

The Ridley Island Propane Export Terminal is expected to be the first propane export facility off the west coast of Canada. The site is near Prince Rupert, British Columbia, on a section of land leased by Ridley Terminals Inc. (RTI) from the Prince Rupert Port Authority (PRPA). The site has a locational advantage given very short shipping distances to markets in Asia, notably a 10-day shipping time compared to 25-days from the U.S. Gulf Coast. The brownfield site also benefits from excellent railway access and ample deep water access to the Pacific Ocean. AltaGas' arrangements with RTI give AltaGas access to extensive land and water rights and a world class marine jetty which allows for the efficient loading of Very Large Gas Carriers that can access key global markets. Propane from British Columbia and Alberta will be transported to the facility using the existing CN rail network. The Ridley Island Propane Export Terminal is estimated to cost approximately $450 to $500 million and is to be designed to ship 1.2 million tonnes of propane per annum. AltaGas has offered a third party the option to take an equity position of up to 30 percent in the Ridley Island Propane Export Terminal. A decision from the third party is expected in the second quarter of 2017.

Based on production from its existing facilities and forecasts from new plants under construction and in active development, AltaGas anticipates having physical volumes equal to approximately 50 percent of the 1.2 million tonnes. The remaining 50 percent is expected to be supplied by producers and aggregators in western Canada. AltaGas expects to underpin at least 40 percent of the Ridley Island Propane Export Terminal throughput under tolling arrangements with producers and other suppliers.

On May 24, 2016, AltaGas LPG Limited Partnership, a wholly owned subsidiary, entered into a Memorandum of Understanding with Astomos Energy Corporation (Astomos) contemplating a multi-year agreement, for the purchase of at least 50 percent of the 1.2 million tonnes of propane available to be shipped from the Ridley Island Propane Export Terminal each year, the key commercial terms of which have been settled. Commercial discussions with Astomos and several other third party off-takers for further capacity commitments are proceeding.

AltaGas began the formal environmental review process in early 2016, which included submission of the Environmental Evaluation Document, review and final determination by federal regulators under terms and conditions that will allow the project to proceed. AltaGas has engaged and worked closely with First Nations throughout the process and will continue to do so as it moves forward with the Ridley Island Propane Export Terminal.

Site preparation and pre-construction activities are underway, and construction is expected to begin in the second quarter of 2017 and will proceed under the self-perform model successfully used by AltaGas to build its other projects on time and on budget. The Ridley Island Propane Export Terminal is expected to be in service by the first quarter of 2019.

Montney Facilities

In January 2017, AltaGas entered into a non-binding letter of intent with a significant Montney producer to construct a 120 Mmcf/d deep-cut natural gas processing facility and a NGL separation train, capable of processing up to 10,000 Bbls/d of NGL mix, and a rail terminal. Negotiation of definitive agreements is currently on hold. AltaGas continues to have discussions with other producers in the Montney.

Early Stage Deep Basin NGL Facility

AltaGas is in the early stages of development of a site in the Deep Basin region of northwest Alberta. AltaGas plans to develop NGL facilities that would serve producers in this region. The NGL facilities will have access to existing rail and can be connected to AltaGas' Ridley Island Propane Export Terminal. Active discussions with producers to contractually underpin the facility are continuing, and engagement with First Nations and key stakeholders is underway. FID is subject to completing commercial arrangements, stakeholder engagement, and regulatory approvals. Depending upon the final designs and components, the facility is expected to cost approximately $30 to $80 million.

Marquette Connector Pipeline

On December 15, 2016, SEMCO Gas filed an application with the Michigan Public Service Commission (MPSC) seeking approval to construct, own, and operate the Marquette Connector Pipeline (MCP). The MCP is a proposed new pipeline that will connect the Great Lakes Gas Transmission pipeline to the Northern Natural Gas pipeline in Marquette, Michigan, which will provide system redundancy and increase deliverability, reliability and diversity of supply to SEMCO Gas' approximately 35,000 customers in Michigan's Western Upper Peninsula. A MPSC decision is expected in the fourth quarter of 2017. The MCP is estimated to cost between US$135 to $140 million with an anticipated in service date in 2020.

Blythe Energy Center (Blythe)

The Blythe Facility, and the Blythe II Facility (Sonoran) currently under development, are well situated to serve a larger western regional transmission organization comprised of several western U.S. states. AltaGas expects that the California market will experience continued supply reductions through the remaining planned retirement of once-through cooling gas plants and nuclear facilities over the next decade. As Publicly Owned Utilities (POUs) and Community Choice Aggregators (CCAs) continue to determine their future resource needs while meeting California's 50 percent renewable portfolio standard, the role of flexible, efficient and dispatchable gas fired generation is expected to change from historical base load supply to supporting the reliability of the electrical system and backstopping the increased intermittent renewable generation. In order to address these needs, AltaGas continues to add flexibility to the existing Blythe facility with increased operating ranges, reduced minimum run and down times, and increased ramp rates as well as securing a second source of gas supply to increase market flexibility. As it relates to both Blythe, following its PPA expiration in July 2020, and the current development project Sonoran, AltaGas continues to have bilateral discussions with POUs, CCAs, municipalities, and corporations for multi-year agreements, while also considering resource adequacy market pricing, potential energy and ancillary service offerings, and alternative configurations (gas, combined with solar and energy storage) using the multiple transmission options and capacity available to best serve AltaGas' potential customers in the desert southwest.

Pomona Facility

Following the 2016 commissioning of the Pomona Energy Storage Facility in response to Southern California Edison's (SCE) Aliso Canyon Emergency request for proposals (RFPs), in the first quarter of 2017 AltaGas received California Independent System Operator (CAISO) certification for participation in the ancillary services market which has expanded the flexibility of the facility to include participation in the regulation market. AltaGas continues to evaluate a future expansion based on SCE's need for additional energy storage at the current site which could readily accommodate a similar size lithium-ion battery project. Separately, and mutually exclusive to the future expansion of the energy storage facility, AltaGas is continuing to evaluate reconfiguring the existing Pomona gas fired facility. In the first quarter of 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission (CEC) to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the CEC will complete the application review process, which will be followed by the City of Pomona and local air district permitting processes. Following approval, AltaGas will be ready to bid the proposed reconfigured gas fired facility into upcoming RFPs or enter into other bilateral contract arrangements. Dependent on prospective customer needs for the peaking unit, AltaGas is considering joint configurations including additional battery storage that would allow for a flexible peaking facility with a zero start-time which is well suited to complement an increasingly large contribution from intermittent renewables.

Energy Storage Development

In October of 2013, the California Public Utilities Commission (CPUC) approved an energy storage procurement target for load serving entities of 1,325 MW of viable and cost effective energy storage by 2020. Pacific Gas & Electric Company, SCE and San Diego Gas & Electric were allocated procurement targets, divided into sub categories of transmission-connected, distribution level and behind the meter applications. AltaGas' success with the Pomona Energy Storage Facility has increased the Corporation's focus on additional energy storage needs of the load serving entities where AltaGas is well suited to develop additional brownfield and greenfield sites in load constrained areas.

2017 Outlook

AltaGas continues to expect to deliver approximately high single digit percentage normalized EBITDA growth in 2017 compared to 2016. All three business segments are expected to drive the annual growth in 2017, with the Gas segment expecting to generate the highest normalized EBITDA growth percentage, followed by the Power segment and the Utilities segment. The Power and Utilities segments are expected to generate approximately 75 percent of 2017 normalized EBITDA. The Gas segment is expected to increase from 23 percent of total 2016 normalized EBITDA to approximately 25 percent of total 2017 normalized EBITDA. The following are the key drivers contributing to the expected normalized EBITDA growth in 2017:

- First full year of commercial operations at the Townsend Facility;
- Higher earnings from frac exposed volumes as a result of the expected recovery in commodity prices;
- Higher expected earnings from the Northwest Hydro Facilities due to continual improvements in operational efficiency and expected contractual price increases;
- Higher expected earnings from Petrogas, including a full year of income from the Petrogas Preferred Share dividends;
- Normal seasonal weather in 2017 compared to unfavorable weather in 2016;
- Contributions from the Pomona Energy Storage Facility, which entered commercial operation on December 31, 2016;
- Decrease in operating and administrative expenses as a result of various cost savings initiatives, including the savings from the Workforce Restructuring that occurred in 2016; and
- Partial contributions from the first train of Townsend Phase 2 entering commercial operations in the fourth quarter of 2017.

The overall forecasted EBITDA growth in 2017 includes the impact from the sale of the EDS and JFP transmission assets to Nova Chemicals, which was completed in March 2017, and scheduled turnarounds at the Edmonton Ethane Extraction Plant (EEEP) and the Turin facility in mid-2017.

Normalized funds from operations are also expected to grow by approximately a high single digit percentage driven by the same factors noted above for normalized EBITDA growth, partially offset by higher current tax expenses and lower common share dividends from Petrogas, as Petrogas is expected to retain a portion of its cash to fund its capital program and for general corporate purposes.

The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets. As part of the financing strategy for the WGL Acquisition, larger asset sales may be undertaken in 2017, subject to market conditions. Any such asset sales, if undertaken, may adversely impact the 2017 outlook for normalized EBITDA and normalized funds from operations, depending on when such sales close during the year.

In the Gas segment, additional earnings in 2017 are expected to be driven by a full year of contributions from the Townsend Facility, higher frac exposed volumes and commodity prices, higher earnings from Petrogas due to improved profitability in the base business, higher volumes expected at the Ferndale Terminal, a full year of income from the Petrogas Preferred Share dividends, and a partial year contribution from the first train of Townsend Phase 2 entering commercial operations in the fourth quarter of 2017. The additional earnings are expected to be offset by the closing of the sale of the EDS and JFP transmission pipelines in the first quarter of 2017 and scheduled turnarounds at EEEP and the Turin facility in mid-2017. Based on current commodity prices, AltaGas estimates an average of approximately 9,500 Bbls/d will be exposed to frac spreads prior to hedging activities. For the remainder of 2017, AltaGas has frac hedges in place for approximately 5,500 Bbls/d at an average price of approximately $23/Bbl excluding basis differentials.

In the Power segment, increased earnings are expected to be driven by higher expected earnings from the Northwest Hydro Facilities as improvements in productivity continue and contractual price increases take effect, contributions from a full year of operations at the Pomona Energy Storage Facility, and lower planned outages expected at Blythe. The earnings and cash flows from the Northwest Hydro Facilities are expected to be seasonally stronger beginning in the second quarter through the end of the third quarter and are expected to decline in the fourth quarter based on seasonal water flow patterns. Actual seasonal water flow will vary with regional temperatures and precipitation levels.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong fourth quarter due to the winter heating season. The Utilities segment is expected to report increased earnings in 2017 mainly driven by the significantly warmer than normal weather experienced at all of the Utilities in 2016, whereas the outlook for 2017 assumes normal weather, and higher customer usage at certain of the Utilities, partially offset by lower interruptible storage service revenue at CINGSA. Earnings at all of the Utilities (except PNG) are affected by weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normal weather, earnings at the utilities would be affected. In addition, earnings from the Utilities segment are impacted by regulatory decisions and the timing of these decisions. In 2017, ENSTAR expects EBITDA to increase by approximately $3 million as a result of the interim refundable rate increase approved in 2016 by the Regulatory Commission of Alaska (RCA), with final rates expected to be set in the third quarter of 2017.

Earnings generated from AltaGas' U.S. assets are exposed to fluctuations in the U.S./Canadian dollar exchange rate, with the strengthening of the U.S. dollar having a positive impact on earnings. However, some of this benefit will be offset by AltaGas' U.S. dollar denominated debt and preferred shares.

Monthly Common Share Dividend and Quarterly Preferred Share Dividends

- The Board of Directors approved a dividend of $0.175 per common share. The dividend will be paid on June 15, 2017, to common shareholders of record on May 25, 2017. The ex-dividend date is May 23, 2017. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.21125 per share for the period commencing March 31, 2017 and ending June 29, 2017, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017;
- The Board of Directors approved a dividend of $0.19571 per share for the period commencing March 31, 2017 and ending June 29, 2017, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing March 31, 2017 and ending June 29, 2017, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing March 31, 2017, and ending June 29, 2017, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017;
- The Board of Directors approved a dividend of $0.296875 per share for the period commencing March 31, 2017, and ending June 29, 2017, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017;
- The Board of Directors approved a dividend of $0.328125 per share for the period commencing March 31, 2017, and ending June 29, 2017, on AltaGas' outstanding Series I Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017; and
- The Board of Directors approved a dividend of $0.4384 per share for the period commencing March 31, 2017, and ending June 29, 2017, on AltaGas' outstanding Series K Preferred Shares. The dividend will be paid on June 30, 2017 to shareholders of record on June 16, 2017. The ex-dividend date is June 14, 2017.

Consolidated Financial Review

	Three Months Ended March 31	
($ millions)	**2017**	2016
Revenue	**771**	611
Normalized EBITDA(1)	**228**	178
Net income applicable to common shares	**32**	55
Normalized net income(1)	**65**	38
Total assets	**10,044**	9,559
Total long-term liabilities	**4,358**	4,770
Net additions to property, plant and equipment	**2**	80
Dividends declared(2)	**88**	73
Normalized funds from operations(1)	**170**	132

	Three Months Ended March 31	
($ per share, except shares outstanding)	**2017**	2016
Net income per common share - basic	**0.19**	0.38
Net income per common share - diluted	**0.19**	0.38
Normalized net income - basic(1)	**0.39**	0.26
Dividends declared(2)	**0.53**	0.50
Normalized funds from operations(1)	**1.01**	0.90
Shares outstanding - basic (millions)		
During the period(3)	**168**	147
End of period	**169**	147

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

(2) Dividends declared per common share per month: $0.165 beginning on October 26, 2015 and $0.175 beginning on August 25, 2016.

(3) Weighted average.

CONFERENCE CALL AND WEBCAST DETAILS:

AltaGas will hold a conference call today at 9:00 a.m. MT (11:00 a.m. ET) to discuss 2017 first quarter results, progress on construction projects and other corporate developments.

Members of the investment community and other interested parties may dial 1-703-318-2220 or call toll free at 1-844-543-5238. The passcode is 91150065. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/invest/events-and-presentations. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing 1-404-537-3406 or 1-855-859-2056. The passcode is 91150065. The replay will expire at 2:00 p.m. (Eastern) on April 28, 2017.

Additional information relating to AltaGas' results can be found in the Management's Discussion and Analysis and unaudited condensed interim consolidated financial statements for the three months ended March 31, 2017 available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

AltaGas is an energy infrastructure company with a focus on natural gas, power and regulated utilities. AltaGas creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca

Investment Community
1-877-691-7199
investor.relations@altagas.ca

Media
(403) 691-7197
media.relations@altagas.ca

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FORWARD LOOKING INFORMATION

This news release contains forward-looking statements. When used in this news release the words “may“, “would“, “could“, “should“, “will“, “intend“, “plan“, “anticipate“, "further", “believe“, "achieve", “aim”, "advance", “seek“, “propose“, "position", “estimate“, “forecast”, “expect“, “project”, “target”, "on track", “potential” and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward-looking statements.

In particular, this news release contains forward-looking statements with respect to, among other things, business objectives; expected growth and drivers of growth; capital expenditures (including in respect of the 2017 capital program; expected allocation per business segment and project and anticipated sources of financing thereof); results of operations; operational and financial performance; business projects; opportunities and financial results, expectations regarding 2017 normalized EBITDA (including expected contributions per business segment and sources of generation); projected growth in normalized EBITDA and normalized funds from operations (including per business segment); AltaGas' continuation of advancement of its strategic initiatives; AltaGas' ability to acquire, grow and optimize energy infrastructure, AltaGas' focus on clean energy sources; AltaGas' commitment to clean energy infrastructure, expectations with respect to the WGL Acquisition including the expected closing date, date of shareholders' meeting, ability to obtain, and timeline for obtaining, regulatory and other approvals, the aggregate cash consideration including the anticipated sources of financing thereof and anticipated indebtedness under the bridge facility, planned asset divestitures (including AltaGas' ability to execute planned asset divestitures in a manner supporting strategy of growing in attractive areas and maintaining long term balanced mix of energy infrastructure), anticipated benefits of the WGL Acquisition including the portfolio of assets of the combined entity, nature, number, value and timing of growth and investment opportunities available to AltaGas, the quality and growth potential of the assets, the strategic focus of the business, strength of the combined entity, complimentary nature of businesses, robustness of assets, ability to increase scale and provide diversity, the combined assets, rate base, customers and rate base growth, and expectations for the Cove Point LNG Terminal including anticipated completion timing; expected use of proceeds from the issuance of subscription receipts; expectations regarding availability of bridge facility; AltaGas' ability to achieve a balanced mix of energy infrastructure and expected timeframe to reach such balance; expectations with respect to the Townsend Facility including, expected earnings and impact on earnings; expectations with respect to Townsend Phase 2 and related infrastructure including design specifications, phased development or development in trains, location, capacity, cost, commitment, take or pay arrangements and expected gas volumes from Painted Pony, compression requirements and cost of compression, connection capability to North Pine Facility, plans for transport including new NGL pipelines, ability to backstop and expected timeline for commercial operations and contribution on earnings; expectations with respect to the proposed Ridley Island Propane Export Terminal including costs, propane transport capability, locational benefits, initial shipment capacity, connection capability, land and water access, quality of transport options, sources of propane supply, AltaGas' ability to construct new plants and develop new projects, expectations regarding tolling arrangements, expectations of being the first propane export terminal off the west coast of British Columbia, sale and purchase of liquefied petroleum gas from the terminal, entering into a multi-year agreement with Astomos, relations with First Nations and Astomos, potential for third party investment, offtake opportunities, expectations of global access, expectations with respect to AltaGas' in-house construction expertise and ability to build on time and on budget, and timing of third party investment, construction and commercial operations; expectations relating to the North Pine Facility and North Pine Pipelines including, construction plans, phased development, connection capability to rail, existing AltaGas infrastructure, the proposed Ridley Island Propane Export Terminal and Alaska highway truck terminal, facility specifications, location, handling capability, service area, cost, product mix, timeline for site preparation, construction and commercial operation and expectations regarding Painted Pony’s gas volumes, commitment and contract; expectations with respect to the Montney Facilities including design specifications, capacity, negotiation of definitive agreements and continuation of discussions with other producers; expectations with respect to the development of the Deep Basin NGL facility including stage of development, facility specifications, location, cost, access to rail, connection capability to the proposed Ridley Island Propane Export Terminal, ability to underpin and target for final investment decision, completion of studies and permitting; expectations relating to the Marquette Connector Pipeline including timeline for MPSC approval, construction and in-service date; cost, location, connection capability to existing pipelines and gas supply opportunities; expectations relating to AltaGas’ ability to fund its projects and business; expectations with respect to the California power market and energy needs of California including expectations regarding the decommissioning of nuclear and coal-fired generation, expected magnitude and timeline for decommissioning and retirement, expectations regarding power *supply and the nature of natural-gas fired power generation and future role thereof; expectations regarding expansion, re-contracting, re-configuring opportunities for Blythe and Blythe II (Sonoran) and ability to offer resource adequacy, energy and ancillary services, use multiple transmission options, serve several western U.S. states, develop Sonoran, enter into multi-year agreements and pursue other opportunities through bilateral discussions or otherwise; expectations regarding the locational benefits of the site for Blythe and Sonoran; expectations relating to the AltaGas Pomona Energy Storage Project including potential expansion opportunities, potential size of expansion, expected energy storage capacity and available resource adequacy, and impact successful commercial operations has on AltaGas, on earnings and potential future development opportunities; expectations with respect to the existing Pomona facility including ability to repower, increase capacity, reconfigure, application review process and timeline, ability to bid into future RFPs and pursue other bilateral arrangements or opportunities; expectations relating to the Northwest Hydro Facilities including expected generation and contributions to earnings and seasonality impacts (including water flow patterns); expected impact on earnings of the Tidewater Gas Asset Disposition; expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including earnings and dividends from Petrogas, Petrogas' retention of cash and contributions to growth of AltaGas; expectations regarding volumes at Ferndale; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains, frac spread exposure, recovery in commodity prices, normal seasonal weather and operating and administrative costs; expectations regarding the impact on earnings of the sale of EDS and JFP pipelines; impact of facility turnarounds and outages on earnings and timing of turnarounds and outages; expected earnings from the utilities segment including from rate base and customer growth and higher customer usage and impact on earnings from lower interruptible storage service revenue from CINGSA and regulatory decisions and timing of regulatory decisions (including in respect of ENSTAR's 2016 rate case and expected decision date and expected revenue increase; AltaGas ability to focus on enhancing productivity and streamlining businesses; expectations regarding the payment of dividends and expectations regarding timing of the conference call.*

These 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 statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including, without limitation, changes in market competition, governmental, aboriginal or regulatory developments, changes in tax legislation, fluctuations in commodity prices, interest or foreign exchange rates, access to capital markets, general economic conditions, changes in the political environment, changes to environmental and other laws and regulations, cost for labour, equipment and materials and other factors set out in AltaGas' continuous disclosure documents, including the Annual Information Form and the MD&A as at and for the year ended December 31, 2016.

Many factors could cause AltaGas' actual results, performance or achievements to vary from those described in this news release, including, without limitation, those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

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

This news release contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the three months ended March 31, 2017. These non-GAAP measures provide additional information that management believes is meaningful regarding AltaGas' 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 in AltaGas' MD&A as at and for the three months ended March 31, 2017. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP.*

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations is provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the three months ended March 31, 2017. This MD&A dated April 25, 2017, should be read in conjunction with the accompanying unaudited condensed interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three months ended March 31, 2017 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2016.

The Consolidated Financial Statements and comparative information have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and in Canadian dollars, unless otherwise indicated.

Abbreviations, acronyms and other capitalized terms used in this MD&A without express definition shall have the same meanings given to those terms in the MD&A as at and for the year ended December 31, 2016.

This MD&A contains forward looking statements. When used in this MD&A the words "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "continue", "estimate", "forecast", "expect", "project", "target", "potential" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward looking statements. In particular, this MD&A contains forward looking statements with respect to, among other things, business objectives, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures and licensing and permitting, expected growth and drivers of growth, capital expenditures (including in respect of the 2017 capital program, expected allocation per business segment and project and anticipated sources of financing thereof), results of operations, operational and financial performance, business projects, opportunities and financial results.

Specifically, such forward looking statements are set forth under the headings: "Overview of the Business", "Developments Relating to the Pending WGL Acquisition", "2017 Outlook", "Growth Capital", and "Future Changes in Accounting Principles" and under those headings specifically include AltaGas' expectations of growth in natural gas supply and demand for clean energy; expectations as to AltaGas' ability to maintain financial strength and flexibility, sufficient liquidity, an investment grade credit rating and ready access to capital markets; expectations with respect to in-house construction expertise; expectations of continued growth in attractive areas; AltaGas' ability to achieve a balanced mix of energy infrastructure assets and expected time frame to reach such balance; expectations regarding 2017 normalized EBITDA (including expected contributions per business segment and sources of generation); projected growth in normalized EBITDA and normalized funds from operations (including per business segment); expectations with respect to the WGL Acquisition including the expected closing date, date of shareholders' meeting, ability to obtain, and timeline for obtaining, regulatory and other approvals, the aggregate cash consideration including the anticipated sources of financing thereof and anticipated indebtedness under the bridge facility, planned asset divestitures, AltaGas' belief with respect to merits of class action suit, anticipated benefits of the WGL Acquisition including the portfolio of assets of the combined entity, nature, number, value and timing of growth and investment opportunities available to AltaGas, the quality and growth potential of the assets, the combined assets, rate base, customers and rate base growth and expectations for the Cove Point LNG Terminal including anticipated completion timing; expected use of proceeds from the issuance of subscription receipts; expectations regarding availability of bridge facility; expectations with respect to the Townsend Facility including, expected earnings and impact on earnings; expectations with respect to Townsend Phase 2 and related infrastructure including design specifications, phased development or development in trains, location, capacity, cost, commitment, take or pay arrangements and expected gas volumes from Painted Pony, compression requirements and cost of compression, and connection capability to North Pine Facility, plans for transport including new NGL pipelines and expected timeline for commercial operations and contribution to earnings; expectations with respect to the proposed Ridley Island Propane Export Terminal including costs, propane transport capability, locational benefits, initial shipment capacity, connection capability, land and water access, quality of transport options, sources of propane supply, AltaGas' ability to construct new plants and develop new projects, expectations regarding tolling arrangements, expectations of being the first propane export terminal off the west coast of British Columbia, sale and purchase of liquefied petroleum gas from the terminal, entering into a multi-year agreement with Astomos, relations with First Nations and Astomos, potential for third party investment and timing of investment *decision, offtake opportunities, expectations of serving growing demand in Asia and offering new markets to producers and timing of construction and commercial operations; expectations relating to the North Pine Facility and North Pine Pipelines including, construction plans, phased development, connection capability to rail, existing AltaGas infrastructure, the proposed Ridley Island Propane Export Terminal and Alaska highway truck terminal, facility specifications, location, handling capability, service area, cost, product mix, timeline for site preparation and commercial operation and expectations regarding Painted Pony's gas volumes, commitment and contract; expectations with respect to the Alton Natural Gas Storage Project including expected natural gas storage capacity, ability to increase reliability of gas supply to AltaGas' distribution customers in the area, ability to continue working in a constructive manner with stakeholders, construction and brining timeline and storage in service date; expectations with respect to the Montney Facilities including design specifications, capacity, negotiation of definitive agreements and continuation of discussions with other producers; expectations with respect to the development of the Deep Basin NGL facility including stage of development, facility specifications, location, cost, access to rail, connection capability to the proposed Ridley Island Propane Export Terminal, ability to underpin and target for final investment decision, completion of studies and permitting; expectations relating to the Marquette Connector Pipeline including timeline for MPSC approval, construction and in-service date, cost, location, connection capability to existing pipelines and gas supply opportunities; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to AltaGas' ability to fund its projects and business; expectations with respect to the California power market and energy needs of California including expectations regarding the decommissioning of nuclear and coal-fired generation, expected magnitude and timeline for decommissioning and retirement, and expectations regarding the future role of natural gas-fired power generation; expectations regarding expansion, re-contracting, re-configuring opportunities for Blythe and Blythe II (Sonoran) and ability to offer resource adequacy, energy and ancillary services, use multiple transmission options to serve several western U.S. states, develop Sonoran, enter into multi-year agreement and pursue other opportunities through bilateral discussions or otherwise; expectations regarding the locational benefits of the site for Blythe and Blythe II; expectations relating to the AltaGas Pomona Energy Storage Project, potential expansion opportunities, potential size of expansion, expected energy storage capacity and available resource adequacy, and impact successful commercial operations has on AltaGas, on earnings and potential future development opportunities; expectations of AltaGas' suitability for developing future energy storage; expectations with respect to the existing Pomona facility including ability to repower, increase capacity, reconfigure, application review process and timeline, ability to bid into future RFPs and pursue other bilateral arrangements or opportunities; expectations relating to the Northwest Hydro Facilities including expected generation and contributions to earnings and seasonality impacts (including water flow patterns); expected impact on earnings of the Tidewater Gas Asset Disposition; expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including earnings and dividends from Petrogas, Petrogas' retention of cash and contributions to growth of AltaGas; expectations regarding volumes at Ferndale; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains, frac spread exposure, recovery in commodity prices, normal seasonal weather and operating and administrative costs; expectations regarding the impact on earnings of the sale of EDS and JFP pipelines; impact of facility turnarounds and outages on earnings and timing of turnarounds and outages; expected earnings from the utilities segment including from rate base and customer growth, from SEMCO Gas as a result of its Main Replacement Program, from ENSTAR in connection with its interim and refundable rate increase and 2016 rate case, from Heritage Gas from its customer retention program, higher customer usage, lower interruptible storage service revenue from CINGSA, AltaGas' ability to focus on enhancing productivity and streamlining businesses; and expectations regarding the adoption of changes in accounting principles and impact on financial statements.*

These 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 statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including, without limitation, changes in market competition, governmental, aboriginal or regulatory developments, changes in tax legislation, fluctuations in commodity prices, interest or foreign exchange rates, access to capital markets, general economic conditions, changes in the political environment, changes to environmental and other laws and regulations, cost for labour, equipment and materials and other factors set out in AltaGas' continuous disclosure documents, including the Annual Information Form and the MD&A as at and for the year ended December 31, 2016.

Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A including, without limitation, those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified by these cautionary statements.

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

Additional information relating to AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

OVERVIEW OF THE BUSINESS

AltaGas, a Canadian corporation, is a North American diversified energy infrastructure company with a focus on owning and operating assets to provide clean and affordable energy to its customers. AltaGas' business strategy is underpinned by strong growth in natural gas supply and the growing demand for clean energy. AltaGas has three business segments:

- Gas, which transacts more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and separation, transmission, storage, and natural gas and NGL marketing, as well as the Corporation's indirectly held one-third interest in Petrogas Energy Corp. (Petrogas), through which its interest in the Ferndale Terminal is held;
- Power, which includes generation assets located across North America with 1,688 MW of gross capacity, all from natural gas and renewable sources, and 20 MW of energy storage; and
- Utilities, serving over 570,000 customers through ownership of regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States, delivering clean and affordable natural gas to homes and businesses.

FIRST QUARTER FINANCIAL HIGHLIGHTS

(Includes non-GAAP financial measures; see discussion in Non-GAAP Financial Measures section of this MD&A)

- Normalized EBITDA was $228 million, an increase of 28 percent compared to $178 million in the first quarter of 2016;
- Normalized funds from operations were $170 million ($1.01 per share), an increase of 29 percent compared to $132 million ($0.90 per share) in the first quarter of 2016;
- Net income applicable to common shares was $32 million ($0.19 per share) compared to $55 million ($0.38 per share) in the first quarter of 2016;
- Normalized net income was $65 million ($0.39 per share), an increase of 71 percent compared to $38 million ($0.26 per share) in the first quarter of 2016;
- Net debt was $3.5 billion as at March 31, 2017, compared to $3.9 billion as at December 31, 2016;
- Debt-to-total capitalization ratio was 42 percent as at March 31, 2017, compared to 46 percent as at December 31, 2016;
- On January 3, 2017, AltaGas announced a positive Final Investment Decision (FID) on the Ridley Island Propane Export Terminal, having received approval from federal regulators;
- On January 25, 2017, AltaGas entered into a definitive agreement (the Merger Agreement) to indirectly acquire WGL Holdings, Inc. (the WGL Acquisition). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of US$6.8 billion, including the assumption of approximately US$2.1 billion of debt as at December 31, 2016;
- On February 3, 2017, AltaGas completed a public offering of 67.8 million subscription receipts, on a bought deal basis (the Bought Deal Offering), at an issue price of $31 per subscription receipt, for total gross proceeds of approximately $2.1 billion. Additionally, AltaGas completed a private placement of approximately 12.9 million subscription receipts at an issue price of $31 per subscription receipt for aggregate gross proceeds of approximately $400 million;
- On February 22, 2017, AltaGas closed a public offering of 12.0 million cumulative 5-year minimum rate reset redeemable preferred shares, Series K, at a price of $25 per share for aggregate gross proceeds of $300 million;
- On March 3, 2017, the over-allotment option granted to the underwriters on the Bought Deal Offering was partially exercised for an additional 3.8 million subscription receipts at an issue price of $31 per subscription receipt for aggregate gross proceeds of approximately $118 million; and
- On March 15, 2017, AltaGas completed the sale of the Ethylene Delivery Systems (EDS) and the Joffre Feedstock Pipeline (JFP) transmission assets to Nova Chemicals Corporation (Nova Chemicals) for net proceeds of approximately $67 million.

CONSOLIDATED FINANCIAL REVIEW

($ millions)	Three Months Ended March 31 2017	2016
Revenue	**771**	611
Normalized EBITDA(1)	**228**	178
Net income applicable to common shares	**32**	55
Normalized net income(1)	**65**	38
Total assets	**10,044**	9,559
Total long-term liabilities	**4,358**	4,770
Net additions to property, plant and equipment	**2**	80
Dividends declared(2)	**88**	73
Normalized funds from operations(1)	**170**	132

($ per share, except shares outstanding)	Three Months Ended March 31 2017	2016
Net income per common share - basic	**0.19**	0.38
Net income per common share - diluted	**0.19**	0.38
Normalized net income - basic(1)	**0.39**	0.26
Dividends declared(2)	**0.53**	0.50
Normalized funds from operations(1)	**1.01**	0.90
Shares outstanding - basic (millions)		
During the period(3)	**168**	147
End of period	**169**	147

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

(2) Dividends declared per common share per month: $0.165 beginning on October 26, 2015 and $0.175 beginning on August 25, 2016.

(3) Weighted average.

Three Months Ended March 31

Normalized EBITDA for the first quarter of 2017 was $228 million, compared to $178 million for the same quarter in 2016. The increase was mainly due to commencement of commercial operations at the Townsend Facility in the third quarter of 2016, the absence of equity losses from the Sundance B PPAs, higher earnings from Petrogas including the dividend income from the Petrogas Preferred Shares, colder weather experienced at certain of the Utilities, higher revenue from NGL marketing, higher realized frac spread and processed volumes, higher natural gas storage margins, contributions from the Pomona Energy Storage Facility which commenced commercial operations on December 31, 2016, and the interim and refundable rate increases at ENSTAR. These increases were partially offset by the weaker U.S. dollar on reported results of the U.S. assets.

Normalized funds from operations for the first quarter of 2017 were $170 million ($1.01 per share), compared to $132 million ($0.90 per share) for the same quarter in 2016, reflecting the same drivers as normalized EBITDA, partially offset by lower common share dividends from Petrogas and higher interest expense. In the first quarter of 2017, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2016 - $nil) and $1 million of common share dividends from Petrogas (2016 - $6 million). Petrogas retained cash to fund its growth capital program and for general corporate purposes.

Operating and administrative expenses for the first quarter of 2017 were $160 million, compared to $132 million for the same quarter in 2016. The increase was mainly due to transaction costs incurred on the pending WGL Acquisition, partially offset by lower employee related costs. Depreciation and amortization expense for the first quarter of 2017 was $72 million, compared to $68 million for the same quarter in 2016. The increase was mainly due to new assets placed into service. Interest expense for the first quarter of 2017 was $46 million, compared to $36 million for the same quarter in 2016. The increase was mainly due to amortization of financing costs associated with the bridge facility obtained for the pending WGL Acquisition, lower capitalized interest, and higher average interest rates, partially offset by lower average debt outstanding. For further information on the bridge facility please see *Developments Relating to the Pending WGL Acquisition* section of this MD&A.

AltaGas recorded income tax expense of $21 million for the first quarter of 2017 compared to $6 million in the same quarter of 2016. The increase was primarily due to the $10 million tax recovery related to the Tidewater Gas Asset Disposition in the first quarter of 2016 and a portion of transaction costs incurred on the pending WGL Acquisition in the first quarter of 2017 not being deductible for tax.

In March 2017, AltaGas completed the sale of the EDS and the JFP transmission assets to Nova Chemicals for net proceeds of approximately $67 million, resulting in a pre-tax loss on disposition of $3 million.

Net income applicable to common shares for the first quarter of 2017 was $32 million ($0.19 per share) compared to $55 million ($0.38 per share) for the same quarter in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition and higher income tax, interest, and depreciation and amortization expense, partially offset by the same previously referenced factors resulting in the increase in normalized EBITDA. In addition, net income per common share decreased for the three months ended March 31, 2017 compared to the same period in 2016 as a result of the same factors impacting net income as well as a higher number of common shares outstanding in 2017.

Normalized net income was $65 million ($0.39 per share) for the first quarter of 2017, compared to $38 million ($0.26 per share) reported for the same quarter in 2016. The increase was driven by the same factors impacting normalized EBITDA, partially offset by higher income tax, interest, and depreciation and amortization expense. Normalizing items in the first quarter of 2017 included after-tax amounts related to transaction costs on acquisitions, unrealized gains on risk management contracts, loss on sale of assets, and amortization of financing costs associated with the bridge facility. In the first quarter of 2016, normalizing items included after-tax amounts related to transaction costs incurred on acquisitions, unrealized gains on risk management contracts, gains on sale of assets and related tax recovery, provision on investment accounted for by the equity method, and dilution loss recognized on investment accounted for by the equity method.

2017 OUTLOOK

AltaGas continues to expect to deliver approximately high single digit percentage normalized EBITDA growth in 2017 compared to 2016. All three business segments are expected to drive the annual growth in 2017, with the Gas segment expecting to generate the highest normalized EBITDA growth percentage, followed by the Power segment and the Utilities segment. The Power and Utilities segments are expected to generate approximately 75 percent of 2017 normalized EBITDA. The Gas segment is expected to increase from 23 percent of total 2016 normalized EBITDA to approximately 25 percent of total 2017 normalized EBITDA. The following are the key drivers contributing to the expected normalized EBITDA growth in 2017:

- First full year of commercial operations at the Townsend Facility;
- Higher earnings from frac exposed volumes as a result of the expected recovery in commodity prices;
- Higher expected earnings from the Northwest Hydro Facilities due to continual improvements in operational efficiency and expected contractual price increases;
- Higher expected earnings from Petrogas, including a full year of income from the Petrogas Preferred Share dividends;
- Normal seasonal weather in 2017 compared to unfavorable weather in 2016;
- Contributions from the Pomona Energy Storage Facility, which entered commercial operation on December 31, 2016;
- Decrease in operating and administrative expenses as a result of various cost savings initiatives, including the savings from the Workforce Restructuring that occurred in 2016; and
- Partial contributions from the first train of Townsend Phase 2 entering commercial operations in the fourth quarter of 2017.

The overall forecasted EBITDA growth in 2017 includes the impact from the sale of the EDS and JFP transmission assets to Nova Chemicals, which was completed in March 2017, and scheduled turnarounds at the Edmonton Ethane Extraction Plant (EEEP) and the Turin facility in mid-2017.

Normalized funds from operations are also expected to grow by approximately a high single digit percentage driven by the same factors noted above for normalized EBITDA growth, partially offset by higher current tax expenses and lower common share dividends from Petrogas, as Petrogas is expected to retain a portion of its cash to fund its capital program and for general corporate purposes.

The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets. As part of the financing strategy for the WGL Acquisition, larger asset sales may be undertaken in 2017, subject to market conditions (see *Developments Relating to the Pending WGL Acquisition* section of this MD&A for further information). Any such asset sales, if undertaken, may adversely impact the 2017 outlook for normalized EBITDA and normalized funds from operations, depending on when such sales close during the year.

In the Gas segment, additional earnings in 2017 are expected to be driven by a full year of contributions from the Townsend Facility, higher frac exposed volumes and commodity prices, higher earnings from Petrogas due to improved profitability in the base business, higher volumes expected at the Ferndale Terminal, a full year of income from the Petrogas Preferred Share dividends, and a partial year contribution from the first train of Townsend Phase 2 entering commercial operations in the fourth quarter of 2017. The additional earnings are expected to be offset by the closing of the sale of the EDS and JFP transmission pipelines in the first quarter of 2017 and scheduled turnarounds at EEEP and the Turin facility in mid-2017. Based on current commodity prices, AltaGas estimates an average of approximately 9,500 Bbls/d will be exposed to frac spreads prior to hedging activities. For the remainder of 2017, AltaGas has frac hedges in place for approximately 5,500 Bbls/d at an average price of approximately $23/Bbl excluding basis differentials.

In the Power segment, increased earnings are expected to be driven by higher expected earnings from the Northwest Hydro Facilities as improvements in productivity continue and contractual price increases take effect, contributions from a full year of operations at the Pomona Energy Storage Facility, and lower planned outages expected at Blythe. The earnings and cash flows from the Northwest Hydro Facilities are expected to be seasonally stronger beginning in the second quarter through the end of the third quarter and are expected to decline in the fourth quarter based on seasonal water flow patterns. Actual seasonal water flow will vary with regional temperatures and precipitation levels.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong fourth quarter due to the winter heating season. The Utilities segment is expected to report increased earnings in 2017 mainly driven by the significantly warmer than normal weather experienced at all of the Utilities in 2016, whereas the outlook for 2017 assumes normal weather, and higher customer usage at certain of the Utilities, partially offset by lower interruptible storage service revenue at CINGSA. Earnings at all of the Utilities (except PNG) are affected by weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normal weather, earnings at the utilities would be affected. In addition, earnings from the Utilities segment are impacted by regulatory decisions and the timing of these decisions. In 2017, ENSTAR expects EBITDA to increase by approximately $3 million as a result of the interim refundable rate increase approved in 2016 by the Regulatory Commission of Alaska (RCA), with final rates expected to be set in the third quarter of 2017.

Earnings generated from AltaGas' U.S. assets are exposed to fluctuations in the U.S./Canadian dollar exchange rate, with the strengthening of the U.S. dollar having a positive impact on earnings. However, some of this benefit will be offset by AltaGas' U.S. dollar denominated debt and preferred shares.

DEVELOPMENTS RELATING TO THE PENDING WGL ACQUISITION

Pending Acquisition of WGL Holdings, Inc.

On January 25, 2017, the Corporation entered into a definitive agreement to indirectly acquire WGL Holdings, Inc. (WGL). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of US$6.8 billion, including the assumption of approximately US$2.1 billion of debt as at December 31, 2016.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia. WGL has a growing midstream business with investments in natural gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeast United States with capabilities for connections to marine-based energy export opportunities via the North American Atlantic coast through the proposed Cove Point LNG terminal in Maryland being developed by a third party, currently expected to be operational in late 2017. WGL also owns contracted clean power assets, with a focus on distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 260,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

The WGL Acquisition is not subject to any financing contingency. AltaGas expects that cash to close the WGL Acquisition will be provided from a combination of the net proceeds from the $400 million private placement of subscription receipts and the $2.2 billion bought deal subscription receipt offering (including the partially exercised over-allotment option) for total gross proceeds of approximately $2.6 billion (see *Subscription Receipts* section below), subsequent offerings of senior debt, hybrid securities, equity or equity-linked securities (including Preferred Shares or convertible debentures), selected AltaGas asset sales and through a fully committed approximately US$3.0 billion bridge facility, which would be available for 12 to 18 months following closing of the WGL Acquisition. AltaGas believes there are a number of attractive, actionable opportunities to monetize certain of its assets in a manner which supports the Corporation's long term strategy of growing in attractive areas and maintaining a long term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. The timing of these subsequent offerings and asset sales is subject to prevailing market conditions, but are generally expected to be completed prior to the closing of the WGL Acquisition.

The WGL Acquisition is subject to certain closing conditions, including approval of WGL common shareholders and certain regulatory and government approvals, including approval by the Public Service Commission of the District of Columbia (PSC of DC), the Maryland Public Service Commission (PSC of MD), the Commonwealth of Virginia State Corporation Commission (SCC of VA), the United States Federal Energy Regulatory Commission (FERC), and the Committee on Foreign Investment in the United States (CFIUS), as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

The special meeting of WGL common shareholders to approve the WGL Acquisition is scheduled for May 10, 2017. In addition, regulatory applications were filed with the PSC of DC, the PSC of MD, the SCC of VA, FERC and CFIUS on April 24, 2017. All decisions are expected to be received in the first half of 2018.

On March 28, 2017, a class action lawsuit was filed by purported shareholders of WGL against WGL, the directors of WGL, AltaGas and Wrangler Inc. (a wholly-owned indirect subsidiary of AltaGas). The directors of AltaGas and the directors of Wrangler Inc. are not named defendants in this lawsuit. This lawsuit alleges that the preliminary proxy statement filed by WGL with the United States Securities and Exchange Commission on March 10, 2017 omitted material information with respect to the pending WGL Acquisition, rendering the proxy statement false and misleading. AltaGas believes that the claims asserted against the defendants in the lawsuit are without merit. In addition, on March 23, 2017, a class action lawsuit was filed by purported shareholders of WGL against WGL and each member of WGL's board of directors alleging that WGL and the board of directors of WGL breached fiduciary duties. AltaGas and the directors of AltaGas are not named defendants in this lawsuit.

Subscription Receipts

On February 3, 2017, the Corporation issued approximately 80.7 million subscription receipts pursuant to a private placement and public offering to partially fund the WGL Acquisition at a price of $31 each for total gross proceeds of approximately $2.5 billion. On March 3, 2017, the over-allotment option was partially exercised for an additional 3.8 million subscription receipts for gross proceeds of approximately $118 million. The sale of the additional subscription receipts pursuant to the over-allotment option brings the aggregate gross proceeds to approximately $2.6 billion. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the WGL Acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments (Dividend Equivalent Payments) per subscription receipt that are equal to dividends declared on each common share. Such Dividend Equivalent Payments will have the same record date as the related common share dividend and will be paid to holders of the subscription receipts concurrently with the payment date of each such common share dividend. The Dividend Equivalent Payments will be paid first out of any interest on the escrowed funds and then out of the escrowed funds. If the Merger Agreement is terminated after the common share dividend declaration date, but before the common share dividend record date, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the Dividend Equivalent Payment. If the Merger Agreement is terminated on a record date or following a record date but on or prior to the dividend payment date, holders will be entitled to receive the full Dividend Equivalent Payment.

The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of WGL and confirmation that the parties to the Merger Agreement are able to complete the WGL Acquisition in all material respects in accordance with the terms of the Merger Agreement, but for the payment of the purchase price, and AltaGas has available to it all other funds required to complete the WGL Acquisition. If the escrow release notice and direction is not delivered on or prior to 5:00 pm (Calgary time) on September 4, 2018, the Corporation will be required to make a termination payment equal to the aggregate issue price of such holder's subscription receipts plus any unpaid Dividend Equivalent Payments owing to such holders of subscription receipts.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $600 to $650 million for 2017. AltaGas' Gas segment will account for approximately 65 to 75 percent of total capital expenditures, while AltaGas' Utility segment will account for approximately 20 to 25 percent and the Power segment will account for approximately 5 to 10 percent. Gas and Power maintenance capital is expected to be approximately $25 to $35 million of total capital expenditures in 2017. The majority of AltaGas' capital expenditures relating to its Gas segment will be allocated towards AltaGas' growth projects including the Ridley Island Propane Export Terminal, the first train of Townsend Phase 2, the North Pine Facility, and the North Pine Pipelines.

AltaGas' 2017 committed capital program is expected to be funded through internally-generated cash flow and the Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP). If required, the Corporation also has approximately $1.9 billion available under its credit facilities as at March 31, 2017, as well as access to capital markets.

Townsend Gas Processing Facility Expansion (Townsend Phase 2)

On February 22, 2017, the Board of Directors approved a positive FID for the first train of Townsend Phase 2 (Townsend 2A). Townsend 2A will be a 99 Mmcf/d shallow-cut gas processing facility to be located on the existing Townsend site, adjacent to the currently operating Townsend Facility. The estimated cost of Townsend 2A is expected to be approximately $80 million and with the addition of incremental field compression equipment to move raw gas production from the Blair Creek area to Townsend, the estimated total cost is expected to be approximately $120 to $140 million. NGL produced from Townsend Phase 2 is expected to be transported to AltaGas' North Pine Facility via existing and planned pipelines owned by AltaGas. Fabrication is underway on several components of Townsend 2A as well as on the incremental field compression equipment. Commercial operation for Townsend 2A is expected to begin in October 2017. AltaGas and Painted Pony Petroleum Ltd. (Painted Pony) have entered into 20-year take-or-pay agreements in respect of Townsend 2A and the incremental field compression equipment, subject to the satisfaction of certain conditions contained in the agreements.

North Pine NGL Project

On October 19, 2016, the Board of Directors approved a positive FID for the construction, ownership and operation of the North Pine Facility to be located approximately 40 km northwest of Fort St. John, British Columbia. The North Pine Facility will be

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connected to existing AltaGas infrastructure in the region and will have access to the CN rail network, allowing for the transportation of propane from the North Pine Facility to the Ridley Island Propane Export Terminal. AltaGas will be constructing the North Pine Facility with two separate NGL separation trains, each capable of processing up to 10,000 Bbls/d of propane plus NGL mix (C3+), for a total of 20,000 Bbls/d. The first phase will also include 6,000 Bbls/d of condensate (C5+) terminalling capacity, with ultimate capacity for up to 20,000 Bbls/d. The second 10,000 Bbls/d NGL separation train is expected to follow after completion of the first train, subject to sufficient commercial support from area producers.

Two eight inch diameter NGL supply pipelines (the North Pine Pipelines), each approximately 40 km in length, will also be constructed to connect AltaGas' existing Alaska Highway truck terminal (the Truck Terminal) to the North Pine Facility. One supply line will carry C3+ with the other carrying C5+. The existing Townsend NGL Egress Pipelines currently delivering product from AltaGas' Townsend Facility will be connected to the North Pine Pipelines to enable shipment of NGL produced at the Townsend Facility directly to the North Pine Facility via the Truck Terminal. Logging, clearing and mulching activities have been completed and civil construction activities will commence in the second quarter of 2017. The target commercial on-stream date for the North Pine Facility and the North Pine Pipelines is expected in the first quarter of 2018, up from the second quarter of 2018.

The capital cost of the first train and associated pipelines is estimated to be approximately $125 to $135 million. This investment will be backstopped by long-term supply agreements with Painted Pony for a portion of the total capacity, and will include dedication of all of Painted Pony's NGL produced at the Townsend and Blair Creek facilities.

On August 8, 2016, Blueberry River First Nations (BRFN) applied for an interlocutory injunction restraining the Province of British Columbia from, among other things, permitting oil and gas activities within BRFN's traditional territory in northeast British Columbia pending resolution of an earlier BRFN action alleging breaches by the Province of British Columbia of BRFN's treaty rights. In the unlikely event the injunction is granted, there could be potential reduction in the future volumes of natural gas available for processing at AltaGas' facilities in this area, although it is AltaGas' understanding that any such exposure is limited. Furthermore, AltaGas does not expect that an injunction will cause delays in the construction of Townsend Phase 2, the North Pine Facility and the North Pine Pipelines as such projects have received approval to construct these facilities from the British Columbia Oil and Gas Commission. The interlocutory injunction was heard from October 31, 2016 to November 4, 2016 and a decision is pending.

Ridley Island Propane Export Terminal

On January 3, 2017, AltaGas reached a positive FID on the Ridley Island Propane Export Terminal, having received approval from federal regulators. AltaGas has executed long-term agreements securing land tenure along with rail and marine infrastructure on Ridley Island.

The Ridley Island Propane Export Terminal is expected to be the first propane export facility off the west coast of Canada. The site is near Prince Rupert, British Columbia, on a section of land leased by Ridley Terminals Inc. (RTI) from the Prince Rupert Port Authority (PRPA). The site has a locational advantage given very short shipping distances to markets in Asia, notably a 10-day shipping time compared to 25-days from the U.S. Gulf Coast. The brownfield site also benefits from excellent railway access and ample deep water access to the Pacific Ocean. AltaGas' arrangements with RTI give AltaGas access to extensive land and water rights and a world class marine jetty which allows for the efficient loading of Very Large Gas Carriers that can access key global markets. Propane from British Columbia and Alberta will be transported to the facility using the existing CN rail network. The Ridley Island Propane Export Terminal is estimated to cost approximately $450 to $500 million and is to be designed to ship 1.2 million tonnes of propane per annum. AltaGas has offered a third party the option to take an equity position of up to 30 percent in the Ridley Island Propane Export Terminal. A decision from the third party is expected in the second quarter of 2017.

Based on production from its existing facilities and forecasts from new plants under construction and in active development, AltaGas anticipates having physical volumes equal to approximately 50 percent of the 1.2 million tonnes. The remaining 50 percent is expected to be supplied by producers and aggregators in western Canada. AltaGas expects to underpin at least 40 percent of the Ridley Island Propane Export Terminal throughput under tolling arrangements with producers and other suppliers.

On May 24, 2016, AltaGas LPG Limited Partnership, a wholly owned subsidiary, entered into a Memorandum of Understanding with Astomos Energy Corporation (Astomos) contemplating a multi-year agreement, for the purchase of at least 50 percent of the 1.2 million tonnes of propane available to be shipped from the Ridley Island Propane Export Terminal each year, the key commercial terms of which have been settled. Commercial discussions with Astomos and several other third party off-takers for further capacity commitments are proceeding.

AltaGas began the formal environmental review process in early 2016, which included submission of the Environmental Evaluation Document, review and final determination by federal regulators under terms and conditions that will allow the project to proceed. AltaGas has engaged and worked closely with First Nations throughout the process and will continue to do so as it moves forward with the Ridley Island Propane Export Terminal.

Site preparation and pre-construction activities are underway, and construction is expected to begin in the second quarter of 2017 and will proceed under the self-perform model successfully used by AltaGas to build its other projects on time and on budget. The Ridley Island Propane Export Terminal is expected to be in service by the first quarter of 2019.

Alton Natural Gas Storage Project

In January 2016, the Government of Nova Scotia issued permits to resume construction of the Alton Natural Gas Storage Project, located near Truro, Nova Scotia. To allow more time for discussions and public engagement, AltaGas deferred major civil construction until summer 2016. Construction resumed on July 5, 2016 and brining for cavern development is now scheduled for 2017. On January 30, 2017, the Supreme Court of Nova Scotia released a decision setting aside the Minister of Environment's (the Minister) April 18, 2016 decision to dismiss an appeal by Sipekne'katik First Nation (SFN) regarding an Industrial Approval (IA) which was issued by the Minister. The Supreme Court has ordered the matter be referred back to the Minister for further action. The IA remains in effect for the Alton Natural Gas Storage Project and the Supreme Court did not issue a stay against further project work. AltaGas continues to work constructively with the Government of Nova Scotia and SFN. The Alton Natural Gas Storage Project is expected to provide up to 10 Bcf of natural gas storage capacity. Storage service is expected to commence in 2020.

Montney Facilities

In January 2017, AltaGas entered into a non-binding letter of intent with a significant Montney producer to construct a 120 Mmcf/d deep-cut natural gas processing facility and a NGL separation train, capable of processing up to 10,000 Bbls/d of NGL mix, and a rail terminal. Negotiation of definitive agreements is currently on hold. AltaGas continues to have discussions with other producers in the Montney.

Early Stage Deep Basin NGL Facility

AltaGas is in the early stages of development of a site in the Deep Basin region of northwest Alberta. AltaGas plans to develop NGL facilities that would serve producers in this region. The NGL facilities will have access to existing rail and can be connected to AltaGas' Ridley Island Propane Export Terminal. Active discussions with producers to contractually underpin the facility are continuing, and engagement with First Nations and key stakeholders is underway. FID is subject to completing commercial arrangements, stakeholder engagement, and regulatory approvals. Depending upon the final designs and components, the facility is expected to cost approximately $30 to $80 million.

Marquette Connector Pipeline

On December 15, 2016, SEMCO Gas filed an application with the Michigan Public Service Commission (MPSC) seeking approval to construct, own, and operate the Marquette Connector Pipeline (MCP). The MCP is a proposed new pipeline that will connect the Great Lakes Gas Transmission pipeline to the Northern Natural Gas pipeline in Marquette, Michigan, which will provide system redundancy and increase deliverability, reliability and diversity of supply to SEMCO Gas' approximately 35,000 customers in Michigan's Western Upper Peninsula. A MPSC decision is expected in the fourth quarter of 2017. The MCP is estimated to cost between US$135 to $140 million with an anticipated in service date in 2020.

Blythe Energy Center (Blythe)

The Blythe Facility, and the Blythe II Facility (Sonoran) currently under development, are well situated to serve a larger western regional transmission organization comprised of several western U.S. states. AltaGas expects that the California market will experience continued supply reductions through the remaining planned retirement of once-through cooling gas plants and nuclear facilities over the next decade. As Publicly Owned Utilities (POUs) and Community Choice Aggregators (CCAs) continue to determine their future resource needs while meeting California's 50 percent renewable portfolio standard, the role of flexible, efficient and dispatchable gas fired generation is expected to change from historical base load supply to supporting the reliability of the electrical system and backstopping the increased intermittent renewable generation. In order to address these needs, AltaGas continues to add flexibility to the existing Blythe facility with increased operating ranges, reduced minimum run and down times, and increased ramp rates as well as securing a second source of gas supply to increase market flexibility. As it relates to both Blythe, following its PPA expiration in July 2020, and the current development project Sonoran, AltaGas continues to have bilateral discussions with POUs, CCAs, municipalities, and corporations for multi-year agreements, while also considering resource adequacy market pricing, potential energy and ancillary service offerings, and alternative configurations (gas, combined with solar and energy storage) using the multiple transmission options and capacity available to best serve AltaGas' potential customers in the desert southwest.

Pomona Facility

Following the 2016 commissioning of the Pomona Energy Storage Facility in response to Southern California Edison's (SCE) Aliso Canyon Emergency request for proposals (RFPs), in the first quarter of 2017 AltaGas received California Independent System Operator (CAISO) certification for participation in the ancillary services market which has expanded the flexibility of the facility to include participation in the regulation market. AltaGas continues to evaluate a future expansion based on SCE's need for additional energy storage at the current site which could readily accommodate a similar size lithium-ion battery project. Separately, and mutually exclusive to the future expansion of the energy storage facility, AltaGas is continuing to evaluate reconfiguring the existing Pomona gas fired facility. In the first quarter of 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission (CEC) to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the CEC will complete the application review process, which will be followed by the City of Pomona and local air district permitting processes. Following approval, AltaGas will be ready to bid the proposed reconfigured gas fired facility into upcoming RFPs or enter into other bilateral contract arrangements. Dependent on prospective customer needs for the peaking unit, AltaGas is considering joint configurations including additional battery storage that would allow for a flexible peaking facility with a zero start-time which is well suited to complement an increasingly large contribution from intermittent renewables.

Energy Storage Development

In October of 2013, the California Public Utilities Commission (CPUC) approved an energy storage procurement target for load serving entities of 1,325 MW of viable and cost effective energy storage by 2020. Pacific Gas & Electric Company, SCE and San Diego Gas & Electric were allocated procurement targets, divided into sub categories of transmission-connected, distribution level and behind the meter applications. AltaGas' success with the Pomona Energy Storage Facility has increased the Corporation's focus on additional energy storage needs of the load serving entities where AltaGas is well suited to develop additional brownfield and greenfield sites in load constrained areas.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures used by AltaGas that do not have a standardized meaning prescribed by 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 GAAP. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures provide additional information that management believes is meaningful in describing AltaGas' 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 and normalized funds from operations throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

($ millions)		Three Months Ended March 31 2017		2016
Normalized EBITDA	**$**	**228**	$	178
Add (deduct):				
Transaction costs related to acquisitions		**(36)**		(2)
Unrealized gains on risk management contracts		**1**		9
Gains (losses) on sale of assets		**(3)**		4
Dilution loss on investment accounted for by the equity method		**—**		(1)
Provision on investment accounted for by the equity method		**—**		(4)
Accretion expenses		**(3)**		(3)
Foreign exchange losses		**—**		(1)
EBITDA	**$**	**187**	$	180
Add (deduct):				
Depreciation and amortization		**(72)**		(68)
Interest expense		**(46)**		(36)
Income tax expense		**(21)**		(6)
Net income after taxes (GAAP financial measure)	**$**	**48**	$	70

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statement of Income using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax expense.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts, transaction costs related to acquisitions, gains (losses) on the sale of assets, accretion expenses, foreign exchange gains (losses), provision on investment accounted for by the equity method, and dilution loss on an investment accounted for by the equity method. AltaGas presents normalized EBITDA as a supplemental measure. 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 Net Income

($ millions)		Three Months Ended March 31 2017		2016
Normalized net income	**$**	**65**	$	38
Add (deduct) after-tax:				
Transaction costs related to acquisitions		**(27)**		(1)
Unrealized gains on risk management contracts		**1**		7
Gains (losses) on sale of assets		**(3)**		14
Dilution loss on investment accounted for by the equity method		**—**		(1)
Provision on investment accounted for by the equity method		**—**		(2)
Amortization of financing costs associated with the bridge facility		**(4)**		—
Net income applicable to common shares (GAAP financial measure)	**$**	**32**	$	55

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts, transaction costs related to acquisitions, gains (losses) on the sale of assets, provision on investment accounted for by the equity method, dilution loss on investment accounted for by the equity method, and amortization of financing costs associated with the bridge facility. This measure is presented in order to enhance the comparability of AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities.

Normalized Funds from Operations

($ millions)	Three Months Ended March 31 2017		2016
Normalized funds from operations	**$**	**170** $	132
Add (deduct):			
Transaction costs related to acquisitions		**(36)**	(2)
Funds from operations		**134**	130
Add (deduct):			
Net change in operating assets and liabilities		**69**	9
Asset retirement obligations settled		**(1)**	(1)
Cash from operations (GAAP financial measure)	**$**	**202** $	138

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Corporation without regard to changes in operating assets and liabilities in the period and non-operating related expenses (net of current taxes) such as transaction costs related to acquisitions.

Funds from operations are calculated from the Consolidated Statement of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations. Management uses this measure to understand the ability to generate funds for capital investments, debt repayment, dividend payments and other investing activities.

Funds from operations and 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 GAAP.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized EBITDA [1]

($ millions)	Three Months Ended March 31 2017		2016
Gas	**$**	**67**	35
Power		**50**	43
Utilities		**115**	108
Sub-total: Operating Segments		**232**	186
Corporate		**(4)**	(8)
	$	**228** $	178

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

GAS

OPERATING STATISTICS

	Three Months Ended March 31 2017	2016
Extraction inlet gas processed (Mmcf/d)(1)	**1,032**	871
FG&P inlet gas processed (Mmcf/d)(1)	**372**	351
Total inlet gas processed (Mmcf/d)(1)	**1,404**	1,222
Extraction ethane volumes (Bbls/d)(1)	**33,683**	29,449
Extraction NGL volumes (Bbls/d)(1) (2)	**38,275**	34,959
Total extraction volumes (Bbls/d)(1) (3)	**71,958**	64,408
Frac spread - realized ($/Bbl)(1) (4)	**10.56**	8.22
Frac spread - average spot price ($/Bbl)(1) (5)	**17.26**	8.22

(1) Average for the period.

(2) NGL volumes refer to propane, butane, and condensate.

(3) Includes Harmattan NGL processed on behalf of customers.

(4) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.

(5) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.

Inlet gas volumes processed at the extraction facilities for the three months ended March 31, 2017 increased by 161 Mmcf/d, compared to the same period in 2016. The increase was primarily due to higher processed volumes at the Joffre Ethane Extraction Plant (JEEP) and at EEEP as a result of normal operations at both plants compared to reinjections and temporary shut-ins driven by low commodity prices in the same period in 2016. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended March 31, 2017 increased by 21 Mmcf/d due to volumes received at the Townsend Facility, partially offset by the impact from the Tidewater Gas Asset Disposition on February 29, 2016, and lower volumes in excess of take-or-pay commitment at the Gordondale facility.

Average ethane volumes for the three months ended March 31, 2017 increased by 4,234 Bbls/d, and NGL volumes increased by 3,316 Bbls/d, compared to the same period in 2016. Higher ethane and NGL volumes were primarily due to normal operations at JEEP and EEEP compared to temporary plant shut-ins and reinjections driven by lower commodity prices in the same period in 2016.

Three Months Ended March 31

The Gas segment reported normalized EBITDA of $67 million in the first quarter of 2017, compared to $35 million in the same quarter of 2016. The increase in normalized EBITDA was due to the Townsend Facility entering commercial operations in the third quarter of 2016, higher equity earnings from Petrogas, higher NGL marketing revenue, higher realized frac spread and processed volumes, and higher natural gas storage margins, partially offset by lower fee-for-service revenue at the Gordondale facility due to lower volumes in excess of the take-or-pay commitment. During the first quarter of 2017, AltaGas recorded equity earnings of $11 million from Petrogas, compared to $2 million in the same period in 2016. The increase in Petrogas earnings was due to dividend income earned by AltaGas from the investment in Petrogas Preferred Shares in June 2016 and improved results from all of Petrogas' business segments. In the first quarter of 2017, Petrogas' earnings benefitted from the continued strengthening of its business segments which support upstream activities, as well as continuing export shipments out of the Ferndale Terminal.

During the first quarter of 2017, AltaGas hedged 5,300 Bbls/d of NGL at an average price of $21/Bbl excluding basis differentials, whereas during the first quarter of 2016, AltaGas did not hedge its NGL volumes. The average indicative spot NGL frac spread for the first quarter of 2017 was approximately $17/Bbl compared to $8/Bbl in the same quarter of 2016. Realized frac spread of $11/Bbl in the first quarter of 2017 (2016 - $8/Bbl) was higher than the same quarter in 2016 due to higher commodity prices.

During the first quarter of 2017, AltaGas recognized a pre-tax loss of $3 million on the sale of the EDS and JFP transmission assets while in the first quarter of 2016, AltaGas recognized a pre-tax gain of $4 million on the Tidewater Gas Asset Disposition.

POWER

OPERATING STATISTICS

	Three Months Ended March 31	
	2017	2016
Renewable power sold (GWh)	**148**	142
Conventional power sold (GWh)	**385**	698
Renewable capacity factor (%)	**9.5**	10.5
Contracted conventional equivalent availability factor (%) [1]	**96.0**	97.6

(1) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.

During the first quarter of 2017, the volume of renewable power sold increased by 6 GWh and the volume of conventional power sold decreased by 313 GWh, compared to the same quarter in 2016. The increase in renewable volumes was due to the addition of the Pomona Energy Storage Facility, which entered service as of December 31, 2016, higher wind conditions at the Bear Mountain wind facility, and increased generation at the Grayling biomass facility. These increases were partially offset by low temperatures contributing to lower river flow at the Northwest Hydro Facilities. The decrease in conventional volumes was due to the termination of the Sundance B PPAs effective March 8, 2016, partially offset by higher dispatch at the Blythe Energy Center despite the planned outage, as the Blythe facility ran through the month of February 2017 providing system reliability to the CAISO network.

Renewable capacity factor for the first quarter of 2017 decreased due to lower river flow, which impacted the hydro capacity factor. Contracted conventional equivalent availability factor was lower in the first quarter of 2017 as a result of the planned outage at the Blythe Energy Centre in the first quarter of 2017, whereas in 2016, the planned outage occurred in the second quarter.

Three Months Ended March 31

The Power segment reported normalized EBITDA of $50 million in the first quarter of 2017, compared to $43 million in the same quarter of 2016. Normalized EBITDA increased due to the absence of equity losses from the Sundance B PPAs, contributions from the Pomona Energy Storage Facility, and higher wind generation at Bear Mountain. These increases were partially offset by the impact of lower river flow at the Northwest Hydro Facilities and the weaker U.S. dollar.

No provisions on long-lived assets or equity investments were recorded in the first quarter of 2017 in the Power segment. In the first quarter of 2016, ASTC Power Partnership (ASTC) exercised its right to terminate the Sundance B PPAs effective March 8, 2016 and as a result, AltaGas recognized a pre-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency.

UTILITIES

OPERATING STATISTICS

	Three Months Ended March 31	
	2017	2016
Canadian utilities		
Natural gas deliveries - end-use (PJ)[1]	**13.5**	12.3
Natural gas deliveries - transportation (PJ)[1]	**1.9**	1.8
U.S. utilities		
Natural gas deliveries - end-use (Bcf)[1]	**30.2**	28.2
Natural gas deliveries - transportation (Bcf)[1]	**15.4**	14.2
Service sites [2]	**576,829**	570,681
Degree day variance from normal - AUI (%) [3]	**(2.2)**	(18.5)
Degree day variance from normal - Heritage Gas (%) [3]	**(1.9)**	(6.9)
Degree day variance from normal - SEMCO Gas (%) [4]	**(11.8)**	(8.5)
Degree day variance from normal - ENSTAR (%) [4]	**9.6**	(21.0)

(1) Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.

(2) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.

(3) A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. 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.

(4) A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 10 years for ENSTAR.

Three Months Ended March 31

The Utilities segment reported normalized EBITDA of $115 million in the first quarter of 2017, compared to $108 million in the same quarter of 2016. The increase was mainly due to colder weather in Alaska, Alberta, and Nova Scotia, interim and refundable rate increases at ENSTAR, and higher customer usage at AUI. These increases were partially offset by unfavorable foreign exchange rates, higher expenses at the U.S. utilities, warmer weather in Michigan, and the impact of Heritage Gas' customer retention program.

CORPORATE

Three Months Ended March 31

In the Corporate segment, normalized EBITDA for the first quarter of 2017 was a loss of $4 million, compared to $8 million in 2016. The decrease was a result of a number of factors including lower employee related costs.

INVESTED CAPITAL

					Three Months Ended March 31, 2017
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**$ 45**	**$ 9**	**$ 17**	**$ —**	**$ 71**
Intangible assets	**1**	**—**	**—**	**1**	**2**
Long-term investments	**14**	**—**	**—**	**—**	**14**
Invested capital	**60**	**9**	**17**	**1**	**87**
Disposals:					
Property, plant and equipment	**(67)**	**(2)**	**—**	**—**	**(69)**
Net invested capital	**$ (7)**	**$ 7**	**$ 17**	**$ 1**	**$ 18**

					Three Months Ended March 31, 2016
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 146	$ 11	$ 16	$ 1	$ 174
Intangible assets	—	—	—	—	—
Long-term investments	71	—	—	—	71
Invested capital	217	11	16	1	245
Disposals:					
Property, plant and equipment	(94)	—	—	—	(94)
Net invested capital	$ 123	$ 11	$ 16	$ 1	$ 151

During the first quarter of 2017, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $87 million, compared to $245 million in the same quarter of 2016. The decrease in additions to property, plant and equipment and intangible assets in the first quarter of 2017 was mainly due to costs incurred during the first quarter of 2016 to complete the construction of the Townsend Facility as well as the purchase of the remaining 51 percent interest in EEEP. The decrease in long-term investments in the first quarter of 2017 was mainly due to the investment in Tidewater Midstream and Infrastructure Ltd. (Tidewater) in the first quarter of 2016, partially offset by the contribution of $14 million to AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) in the first quarter of 2017 to fund a scheduled repayment of a note payable related to AIJVLP's acquisition of Petrogas in 2014. The disposals of property, plant and equipment in the first quarter of 2017 primarily related to the sale of the EDS and JFP transmission assets, while in the first quarter of 2016 the disposals of property, plant and equipment related to the Tidewater Gas Asset Disposition.

The invested capital in the first quarter of 2017 included maintenance capital of $nil (2016 - $nil) in the Gas segment and $3 million (2016 - $4 million) in the Power segment.

RISK MANAGEMENT

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. At times, AltaGas will enter into financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas' risk management control framework. Financial derivative instruments are governed under, and subject to, this policy. As at March 31, 2017 and December 31, 2016, the fair values of the Corporation's derivatives were as follows:

($ millions)	**March 31, 2017**	December 31, 2016
Natural gas	**$ 2**	$ 4
Storage optimization	**—**	(3)
NGL frac spread	**(5)**	(12)
Power	**32**	30
Foreign exchange	**15**	—
Net derivative asset	**$ 44**	$ 19

Commodity Price Contracts

From time to time, the Corporation executes gas, power, and other commodity contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. The fair value of power, natural gas, and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. Changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income in the period in which the change occurs.

The Power segment has various fixed price power purchase and sale contracts in the Alberta market, which are expected to be settled over the next five years. The average Alberta spot price for the three months ended March 31, 2017 was approximately \$22/MWh (2016 – \$18/MWh).

The Corporation also executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. The average indicative spot NGL frac spread for the three months ended March 31, 2017 was \$17/Bbl (2016 – \$8/Bbl). The average NGL frac spread realized by AltaGas for the three months ended March 31, 2017 was approximately \$11/Bbl inclusive of basis differentials (2016 - \$8/Bbl). For the remainder of 2017, AltaGas currently has frac hedges in place to hedge approximately 5,500 Bbls/d at an average price of \$23/Bbl, excluding basis differentials.

Foreign Exchange

AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation's earnings, cash flows, and other comprehensive income are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated by AltaGas' U.S. dollar-denominated debt and preferred shares. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at March 31, 2017, AltaGas had no material foreign exchange forward contracts outstanding.

In addition, as at March 31, 2017, management designated US\$317 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2016 - US\$301 million). U.S. dollar denominated long-term debt instruments have been designated as a hedge of the net investment in foreign subsidiaries. This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on U.S. dollar denominated long-term debt and foreign net investment. For the three months ended March 31, 2017, AltaGas incurred an after-tax unrealized gain of \$1 million arising from the translation of debt in other comprehensive income (2016 – after-tax unrealized gain of \$51 million).

To mitigate the foreign exchange risks associated with the cash purchase price of WGL, AltaGas has entered into foreign currency option contracts with an aggregate notional value of US\$500 million. These foreign currency option contracts did not qualify for hedge accounting. Therefore, all changes in fair value are recognized in net income. For the three months ended March 31, 2017, an unrealized loss of \$6 million was recognized under "unrealized gains and losses from risk management contracts" in relation to these contracts. Subsequent to quarter end, AltaGas entered into additional foreign currency option contracts with an aggregate notional value of US\$675 million.

The Effects of Derivative Instruments on the Consolidated Statements of Income

The following table presents the unrealized gains (losses) on derivative instruments as recorded in the Corporation's Consolidated Statements of Income:

		Three Months Ended March 31		
($ millions)		**2017**		2016
Natural gas	**$**	**(2)**	$	(1)
Storage optimization		**2**		(2)
NGL frac spread		**8**		—
Power		**—**		12
Foreign exchange		**(7)**		—
	$	**1**	$	9

Please refer to Note 19 of the 2016 Annual Consolidated Financial Statements and Note 9 of the unaudited condensed interim Consolidated Financial Statements as at and for the three months ended March 31, 2017 for further details regarding AltaGas' risk management activities.

LIQUIDITY

($ millions)	Three Months Ended March 31 2017	2016
Cash from operations	**$ 202**	$ 138
Investing activities	**(46)**	(152)
Financing activities	**(143)**	(272)
Increase (decrease) in cash and cash equivalents	**$ 13**	$ (286)

Cash from Operations

Cash from operations increased by $64 million for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to a favorable variance in the net change in operating assets and liabilities, and higher distributions from equity investments, partially offset by lower earnings. The favorable variance in net change in operating assets and liabilities was primarily due to colder weather in the first quarter of 2017 as compared to 2016, resulting in lower inventory and higher accounts payable, partially offset by higher billings resulting in higher accounts receivable in the Utilities segment. In addition, accounts payable in the Corporate and Gas segments had a favorable variance due to higher property and carbon tax payable and the addition of the Townsend Facility in the third quarter of 2016, respectively.

Working Capital

($ millions except current ratio)	**March 31, 2017**	December 31, 2016
Current assets	**$ 560**	$ 739
Current liabilities	**811**	996
Working capital (deficiency)	**$ (251)**	$ (257)
Working capital ratio	**0.69**	0.74

The decrease in working capital ratio was primarily due to the decrease in inventory and the completion of the sale of transmission assets to Nova Chemicals, which were previously classified as assets held for sale, partially offset by the decrease in short-term debt and a lower current portion of long-term debt due as compared to December 31, 2016. Cash from the sale of assets was mainly used to repay borrowings under credit facilities. AltaGas' working capital will fluctuate in the normal course of business and the working capital deficiency will be funded using cash flow from operations, DRIP and available credit facilities as required.

Investing Activities

Cash used in investing activities for the three months ended March 31, 2017 was $46 million, compared to $152 million in the same period in 2016. Investing activities for the three months ended March 31, 2017 primarily included expenditures of approximately $86 million for property, plant, and equipment, approximately $21 million for derivative contracts, and approximately $14 million of contributions to AltaGas' equity investments, partially offset by cash proceeds of approximately $69 million, net of transaction costs, primarily from the sale of the EDS and JFP transmission assets, and cash inflow of approximately $8 million from Petrogas to repay a portion of its outstanding loan. Investing activities for the three months ended March 31, 2016 primarily included expenditures of approximately $153 million for property, plant, and equipment and approximately $21 million for the purchase of EEEP, partially offset by cash inflow of approximately $29 million, net of transaction costs, from the Tidewater Gas Asset Disposition.

Financing Activities

Cash used in financing activities for the three months ended March 31, 2017 was $143 million, compared to $272 million in the same period of 2016. Financing activities for the three months ended March 31, 2017 were primarily comprised of net proceeds from the issuance of preferred shares of $294 million and common shares of $62 million (including common shares issued through the DRIP), and borrowings under the credit facilities of $14 million, partially offset by the repayments of long-term debt and short-term debt of $287 million and $123 million, respectively. Financing activities for the three months ended March 31, 2016 were primarily comprised of borrowings under credit facilities of $282 million and issuance of common shares of $29 million, partially offset by repayments of long-term debt and short-term debt of $408 million and $87 million, respectively. Total dividends paid to common and preferred shareholders of AltaGas for the three months ended March 31, 2017 were $100 million (2016 - $86 million), of which $58 million was reinvested through the DRIP during the three months ended March 31, 2017 (2016 - $27 million). The increase in dividends paid was due to more common shares and preferred shares outstanding and dividend increases on common shares declared in the second half of 2016. The increase in the amounts reinvested through the DRIP for the three months ended March 31, 2017 compared to the same period in 2016 was due to the implementation of the Premium Dividend™ component of the plan effective May 2016. Please refer to Note 10 of the unaudited interim condensed Consolidated Financial Statements for the three months ended March 31, 2017 for more information about the DRIP.

CAPITAL RESOURCES

AltaGas' objective for managing capital is to maintain its investment grade credit ratings, ensure adequate liquidity, maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas' capital structure is comprised of shareholders' equity (including non-controlling interests), short-term and long-term debt (including current portion) less cash and cash equivalents.

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

($ millions)	**March 31, 2017**	December 31, 2016
Short-term debt	**$ 5**	$ 129
Current portion of long-term debt	**357**	383
Long-term debt(1)	**3,131**	3,367
Total debt	**3,493**	3,879
Less: cash and cash equivalents	**(32)**	(19)
Net debt	**$ 3,461**	$ 3,860
Shareholders' equity	**4,840**	4,581
Non-controlling interests	**36**	35
Total capitalization	**$ 8,337**	$ 8,476
Debt-to-total capitalization (%)	**42**	46

(1) Net of debt issuance costs of $14 million as at March 31, 2017 (December 31, 2016 - $14 million).

On February 22, 2017, AltaGas closed a public offering of 12,000,000 cumulative 5-year minimum rate reset redeemable preferred shares, Series K, at a price of $25 per Series K preferred share for aggregate gross proceeds of $300 million. Net proceeds were used to reduce existing indebtedness and for general corporate purposes.

As at March 31, 2017, AltaGas’ total debt primarily consisted of outstanding MTNs of $2.6 billion (December 31, 2016 - $2.8 billion), PNG debenture notes of $43 million (December 31, 2016 - $43 million), SEMCO long-term debt of $493 million (December 31, 2016 - $500 million) and $328 million drawn under the bank credit facilities (December 31, 2016 - $501 million). In addition, AltaGas had $122 million of letters of credit (December 31, 2016 - $161 million) outstanding.

As at March 31, 2017, AltaGas’ total market capitalization was approximately $5.2 billion based on approximately 169 million common shares outstanding and a closing trading price on March 31, 2017 of $30.80 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended March 31, 2017 was 2.3 times (12 months ended March 31, 2016 – 1.3 times).

™ Denotes trademark of Canaccord Genuity Corp.

Credit Facilities

($ millions)	Borrowing capacity	**Drawn at March 31, 2017**	Drawn at December 31, 2016
Demand operating facilities	$ 70	**$ 4**	$ 4
Extendible revolving letter of credit facility	150	**36**	49
Letter of credit demand facility	150	**78**	104
PNG operating facility	25	**6**	10
AltaGas Ltd. revolving credit facility (1)	1,400	**323**	378
AltaGas Ltd. revolving US$300 million credit facility (1) (2)	399	**—**	—
SEMCO Energy US$150 million unsecured credit facility (1) (2)	200	**3**	117
	$ 2,394	**$ 450**	$ 662

(1) Amount drawn at March 31, 2017 converted at the month-end rate of 1 U.S. dollar = 1.3310 Canadian dollar (December 31, 2016 - 1 U.S. dollar = 1.3427 Canadian dollar).

(2) Borrowing capacity was converted at the March 31, 2017 U.S./Canadian dollar month-end exchange rate.

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas and its subsidiaries have been in compliance with all financial covenants each quarter since the establishment of the facilities.

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

Ratios	Debt covenant requirements	**As at March 31, 2017**
Bank debt-to-capitalization(1)	not greater than 65 percent	41.2%
Bank EBITDA-to-interest expense (1) (2)	not less than 2.5x	4.0
Bank debt-to-capitalization (SEMCO)(3)	not greater than 60 percent	38.8%
Bank EBITDA-to-interest expense (SEMCO)(3)	not less than 2.25x	6.9

(1) Calculated in accordance with the Corporation's credit facility agreement, which is available on SEDAR at www.sedar.com.

(2) Estimated, subject to final adjustments.

(3) Bank EBITDA-to-interest expense (SEMCO) and Bank debt-to-capitalization (SEMCO) are calculated based on SEMCO's consolidated financial statements and are calculated similar to Bank debt-to-capitalization and Bank EBITDA-to-interest expense.

On August 10, 2015, a $5 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, by disclosing standardized information required for such issuances. As at March 31, 2017, $1.2 billion remains available under the base shelf prospectus.

RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. There were no significant changes in the nature of the related party transactions described in Note 26 of the 2016 Annual Consolidated Financial Statements.

SHARE INFORMATION

	As at April 21, 2017
Issued and outstanding	
Common shares	169,565,041
Preferred Shares	
Series A	5,511,220
Series B	2,488,780
Series C	8,000,000
Series E	8,000,000
Series G	8,000,000
Series I	8,000,000
Series K	12,000,000
Subscription Receipts	84,510,000
Issued	
Share options	4,679,261
Share options exercisable	3,197,008

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

On February 22, 2017, AltaGas closed a public offering of the Series K preferred shares. Holders of the Series K preferred shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding March 31, 2022 at an annual rate of 5.0 percent, payable on the last day of March, June, September and December, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payment is payable on June 30, 2017 in the amount of $0.4384 per Series K Preferred Share. The dividend rate will reset on March 31, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.8 percent, provided that, in any event, such rate shall not be less than 5.0 percent per annum.

The following table summarizes AltaGas' dividend declaration history:

Dividends
Year ended December 31

($ per common share)	**2017**	2016
First quarter	**$ 0.52500**	$ 0.49500
Second quarter	—	0.49500
Third quarter	—	0.51500
Fourth quarter	—	0.52500
Total	**$ 0.52500**	$ 2.03000

Series A Preferred Share Dividends
Year ended December 31

($ per preferred share)	**2017**	2016
First quarter	**$ 0.21125**	$ 0.21125
Second quarter	—	0.21125
Third quarter	—	0.21125
Fourth quarter	—	0.21125
Total	**$ 0.21125**	$ 0.84500

Series B Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		2017		2016
First quarter	$	**0.19541**	$	0.19269
Second quarter		**—**		0.19393
Third quarter		**—**		0.20109
Fourth quarter		**—**		0.19921
Total	**$**	**0.19541**	$	0.78692

Series C Preferred Share Dividends

Year ended December 31 *(US$ per preferred share)*		2017		2016
First quarter	$	**0.27500**	$	0.27500
Second quarter		**—**		0.27500
Third quarter		**—**		0.27500
Fourth quarter		**—**		0.27500
Total	**$**	**0.27500**	$	1.10000

Series E Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		2017		2016
First quarter	$	**0.31250**	$	0.31250
Second quarter		**—**		0.31250
Third quarter		**—**		0.31250
Fourth quarter		**—**		0.31250
Total	**$**	**0.31250**	$	1.25000

Series G Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		2017		2016
First quarter	$	**0.296875**	$	0.296875
Second quarter		**—**		0.296875
Third quarter		**—**		0.296875
Fourth quarter		**—**		0.296875
Total	**$**	**0.296875**	$	1.187500

Series I Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		2017		2016
First quarter	$	**0.328125**	$	0.463870
Second quarter		**—**		0.328125
Third quarter		**—**		0.328125
Fourth quarter		**—**		0.328125
Total	**$**	**0.328125**	$	1.448245

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. Other than as described below, AltaGas' significant accounting policies have remained unchanged and are contained in the notes to the 2016 Annual 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.

AltaGas' critical accounting estimates continue to be financial instruments, depreciation and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessments, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities. For a full discussion of these accounting estimates, refer to the 2016 Annual Consolidated Financial Statements and MD&A.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2017, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2015-11 “Inventory: Simplifying the Measurement of Inventory”. The amendments in this ASU require an entity to measure inventory at the lower of cost and net realizable value. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-05 “Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships”. The amendments in this ASU clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-06, “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-07 “Investments - Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focuses on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. Upon adoption of this ASU, AltaGas elected as an accounting policy to account for forfeitures when they occur instead of estimating the number of awards that are expected to vest. The ASU requires this change to be adopted using the modified retrospective approach and as a result, AltaGas recorded a decrease to accumulated retained earnings of approximately $1 million and an increase to contributed surplus of approximately $1 million. The deferred tax impact was immaterial. The remaining amendments to this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, FASB issued ASU No. 2014-09 “Revenue from Contracts with Customers”, which will replace numerous requirements in U.S. GAAP, including industry-specific requirements, and provide companies with a single revenue recognition model for recognizing revenue from contracts with customers. The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 "Principal versus Agent Consideration". The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 "Identifying Performance Obligation and Licensing", which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 "Narrow Scope Improvements and Practical Expedients", clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. In December 2016, FASB issued ASU No. 2016-20 "Technical Corrections and Improvements", which makes minor technical corrections and improvements to the new revenue standard. The new revenue standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Although early adoption is permitted, AltaGas will adopt ASU No. 2014-09 during the first quarter of 2018. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A preliminary scoping exercise was completed for AltaGas' operating segments and, while AltaGas is continuing to assess all potential impacts of the standard, AltaGas anticipates that the new standard will mostly impact the Gas and Utilities segments with regards to the timing of revenue recognition under the ASU for contracts that have take-or-pay features. AltaGas is still in the process of evaluating these impacts. AltaGas is currently progressing through contract reviews in order to identify and quantify potential differences. AltaGas is also awaiting further guidance from the AICPA Power and Utility Entities Revenue Recognition Task Force related to the income statement presentation of revenue from alternative revenue programs. The ASU permits the use of either the full retrospective or modified retrospective transition method and AltaGas currently anticipates using the modified retrospective transition method.

In January 2016, FASB issued ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revises 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 amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas' financial statements.

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. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements but expects the new standard will have an impact on the Corporation's balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption.

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 periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments". The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2016, FASB issued ASU No. 2016-16 "Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory". The amendments in this ASU revise the accounting for income tax consequences on intra-entity transfer of assets by requiring an entity to recognize current and deferred tax on intra-entity transfer of assets other than inventory when the transfer occurs. The amendment in this ASU is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In November 2016, FASB issued ASU No. 2016-18 "Statement of Cash Flows: Restricted Cash". The amendments in this ASU require 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 amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU retrospectively to each period presented. Early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated cash flow statements.

In January 2017, FASB issued ASU No. 2017-01 "Business Combinations: Clarifying the Definition of a Business". The amendments in this ASU change the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis on or after the effective date. AltaGas will apply the amendments prospectively.

In January 2017, FASB issued ASU No. 2017-04 "Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment". The ASU removes Step 2 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. An entity should adopt the amendments in this ASU for annual periods beginning after December 15, 2020, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In February 2017, FASB issued 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 clarify the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The effective date and transition requirements for the amendments in this ASU are the same as the effective date and transition requirements for ASU No. 2014-09, which is effective for fiscal years and interim periods beginning on or after December 15, 2017. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In March 2017, FASB issued 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 revise the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limit the components that are eligible for capitalization in assets to only the service cost component. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. The amendments in this ASU should be applied retrospectively for the presentation of the service cost component and the other components of net benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of the subscription receipts and the net proceeds thereof held in escrow as described under the *Developments Relating to the Pending WGL Acquisition* section of this MD&A, AltaGas did not enter into any material off-balance sheet arrangements during the three months ended March 31, 2017. Reference should be made to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2016 for information on off-balance sheet arrangements.

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

AltaGas' management, including its Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining DCP and ICFR, as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability, and transparency of information that is filed or submitted under securities legislation.

AltaGas’ management, including the Chief Executive Officer and the Chief Financial Officer, have designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that information required to be disclosed by AltaGas in its annual filings, interim filings or other reports to be filed or submitted by it under securities legislation is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with U.S. GAAP.

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

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR as at March 31, 2017 and concluded that as at March 31, 2017, AltaGas' DCP and ICFR were effective.

During the first quarter of 2017, there were no changes made to AltaGas’ ICFR that materiality affected, or are reasonably likely to materially affect, its ICFR.

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.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS [(1)]

($ millions)	**Q1-17**	Q4-16	Q3-16	Q2-16	Q1-16	Q4-15	Q3-15	Q2-15
Total revenue	**771**	661	492	426	611	580	452	416
Normalized EBITDA[(2)]	**228**	194	176	153	178	173	125	107
Net income (loss) applicable to common shares	**32**	38	46	16	55	(54)	20	(22)
($ per share)	**Q1-17**	Q4-16	Q3-16	Q2-16	Q1-16	Q4-15	Q3-15	Q2-15
Net income (loss) per common share								
Basic	**0.19**	0.23	0.28	0.10	0.38	(0.37)	0.15	(0.16)
Diluted	**0.19**	0.23	0.28	0.10	0.38	(0.37)	0.14	(0.16)
Dividends declared	**0.53**	0.53	0.52	0.50	0.50	0.50	0.48	0.47

(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.

AltaGas’ quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the U.S./Canadian dollar exchange rate, planned and unplanned plant outages, timing of in-service dates of new projects, and acquisition and divestiture activities.

Revenue for the Utilities 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 run-of-river hydroelectric facilities in British Columbia are also impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months.

Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The Harmattan and Younger turnarounds in the second quarter of 2015;
- The San Joaquin Facilities acquired on November 30, 2015;
- The commissioning of McLymont in the fourth quarter of 2015;
- The weak NGL commodity prices throughout 2015 and 2016;
- The closing of the Tidewater Gas Asset Disposition on February 29, 2016;
- The stronger U.S. dollar on translated results of the U.S. assets throughout 2015 and 2016;
- The weak Alberta power pool prices throughout 2016;
- The seasonally warmer weather experienced at all of the Utilities in the first quarter of 2016;
- The commencement of commercial operations early in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the Townsend Facility, gas gathering line, NGL egress pipelines and truck terminal;
- The recovery of $7 million of development costs related to the PNG Pipeline Looping Project in the third quarter of 2016; and
- The commissioning of the Pomona Energy Storage Facility on December 31, 2016.

Net income (loss) applicable to common shares is also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on assets and gains or losses on the sale of assets. In addition, net income (loss) applicable to common shares is also impacted by preferred share dividends. For these reasons, the net income (loss) may not necessarily reflect the same trends as revenue. Net income (loss) applicable to common shares during the periods noted was impacted by:

- Higher depreciation and amortization expense due to new assets placed into service or acquired, partially offset by lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition on February 29, 2016;
- Higher interest expense mainly due to new assets placed into service and interest no longer eligible for capitalization, and a higher average debt balance since the fourth quarter of 2015 as a result of the acquisition of the San Joaquin Facilities. In the first quarter of 2017, interest expense was also higher due to the amortization of financing costs associated with the bridge facility;
- A one-time non-cash expense of $14 million related to the revaluation of deferred income tax liabilities based on the increased Alberta corporate income tax rate from 10 to 12 percent in the second quarter of 2015;
- An after-tax provision of $6 million related to the planned sale of certain development stage wind assets in northern California in the third quarter of 2015;
- After-tax provisions totaling $114 million in the fourth quarter of 2015 related to AltaGas' investment in common shares of Painted Pony, investment in ASTC, investment in its joint ventures with Idemitsu Kosan Co.,Ltd. and the DC LNG Project, certain wind development projects, certain gas processing assets that were held for sale, and AltaGas' one-third interest in Inuvik Gas Ltd. and assets in the Ikhil Joint Venture;
- An after-tax gain on sale of $14 million in the first quarter of 2016 related to the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta;
- After-tax restructuring charges of $5 million in the second quarter of 2016 related to the Workforce Restructuring;
- The termination of the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs and as a result, AltaGas recognized an after-tax provision of $4 million on its investment in ASTC to

settle the working capital deficiency in the first quarter of 2016. In addition, AltaGas recognized a pre-tax termination expense of $8 million (after-tax $7 million) upon reaching a definitive settlement agreement with the Government of Alberta regarding the termination of the Sundance B PPAs in the fourth quarter of 2016. Including the tax recovery on the dissolution of ASTC of $8 million, the after-tax impact on the termination of the Sundance B PPAs was approximately $3 million; and

- After-tax transaction costs of approximately $27 million related to the pending WGL Acquisition incurred in the first quarter of 2017.

Consolidated Balance Sheets

(condensed and unaudited)

As at *($ millions)*	**March 31, 2017**	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	**$ 32.4**	$ 19.0
Accounts receivable, net of allowances	**321.9**	338.8
Inventory *(note 5)*	**128.8**	221.0
Restricted cash holdings from customers	**4.0**	5.0
Regulatory assets	**1.9**	0.9
Risk management assets *(note 9)*	**40.5**	40.4
Prepaid expenses and other current assets	**30.1**	42.8
Assets held for sale *(note 4)*	**—**	70.7
	559.6	738.6
Property, plant and equipment	**6,722.8**	6,734.9
Intangible assets	**681.3**	694.3
Goodwill *(note 6)*	**850.9**	856.0
Regulatory assets	**322.5**	329.1
Risk management assets *(note 9)*	**41.6**	24.1
Deferred income taxes	**2.8**	2.8
Restricted cash holdings from customers	**8.0**	10.1
Long-term investments and other assets	**213.4**	189.3
Investments accounted for by the equity method	**641.3**	621.4
	$ 10,044.2	$ 10,200.6
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 344.6**	$ 345.8
Dividends payable	**29.5**	29.2
Short-term debt	**5.1**	128.7
Current portion of long-term debt *(notes 7 and 9)*	**356.6**	383.4
Customer deposits	**22.4**	35.5
Regulatory liabilities	**9.3**	16.6
Risk management liabilities *(note 9)*	**23.5**	32.9
Other current liabilities	**19.8**	23.6
Liabilities associated with assets held for sale *(note 4)*	**—**	0.4
	810.8	996.1
Long-term debt *(notes 7 and 9)*	**3,130.8**	3,366.9
Asset retirement obligations	**81.5**	81.6
Deferred income taxes	**624.7**	621.7
Regulatory liabilities	**169.4**	170.5
Risk management liabilities *(note 9)*	**15.4**	12.6
Other long-term liabilities	**206.1**	206.3
Future employee obligations *(note 13)*	**129.7**	129.5
	$ 5,168.4	$ 5,585.2

As at *($ millions)*		**March 31, 2017**		December 31, 2016
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2017 - 168.9 million and 2016 - 166.9 million issued and outstanding *(note 10)*	**$**	**3,835.3**	$	3,773.4
Preferred shares *(note 10)*		**1,280.5**		985.1
Contributed surplus		**18.5**		17.4
Accumulated deficit		**(658.0)**		(600.4)
Accumulated other comprehensive income (AOCI) *(note 8)*		**363.8**		405.1
Total shareholders' equity		**4,840.1**		4,580.6
Non-controlling interests		**35.7**		34.8
Total equity		**4,875.8**		4,615.4
	$	**10,044.2**	$	10,200.6

Commitments, contingencies and guarantees (notes 3 and 12).
Subsequent events (note 18).

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

For the three months ended March 31 *($ millions except per share amounts)*	**2017**	2016
REVENUE		
Regulated operations	**$ 415.0**	$ 380.8
Services	**203.0**	182.0
Sales	**152.2**	38.8
Other revenue	**0.1**	—
Unrealized gains on risk management contracts *(note 9)*	**0.9**	8.9
	771.2	610.5
EXPENSES		
Cost of sales, exclusive of items shown separately	**434.1**	288.7
Operating and administrative	**160.1**	131.6
Accretion expenses	**2.8**	2.8
Depreciation and amortization	**71.5**	68.4
	668.5	491.5
Income (loss) from equity investments	**14.1**	(10.7)
Other income (loss) *(note 4)*	**(2.1)**	4.4
Foreign exchange gains (losses)	**0.3**	(0.6)
Interest expense		
Short-term debt	**(0.8)**	(0.1)
Long-term debt	**(45.2)**	(36.0)
Income before income taxes	**69.0**	76.0
Income tax expense (recovery) *(note 14)*		
Current	**11.4**	10.0
Deferred	**9.9**	(4.1)
Net income after taxes	**47.7**	70.1
Net income applicable to non-controlling interests	**2.3**	2.8
Net income applicable to controlling interests	**45.4**	67.3
Preferred share dividends	**(13.6)**	(12.0)
Net income applicable to common shares	**$ 31.8**	**$** 55.3
Net income per common share *(note 11)*		
Basic	**$ 0.19**	$ 0.38
Diluted	**$ 0.19**	$ 0.38
Weighted average number of common shares outstanding (millions) *(note 11)*		
Basic	**167.9**	146.8
Diluted	**168.3**	147.2

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

(condensed and unaudited)

For the three months ended March 31 *($ millions)*		**2017**		2016
Net income after taxes	**$**	**47.7**	$	70.1
Other comprehensive income (loss), net of taxes				
Losses on foreign currency translation		**(24.2)**		(177.3)
Unrealized gains on net investment hedge *(note 9)*		**1.4**		51.1
Reclassification of actuarial gains and prior service costs on defined benefit and PRB plans to net income *(note 13)*		**0.1**		0.1
Unrealized gain (loss) on available-for-sale assets		**(17.4)**		3.2
Other comprehensive income (loss) from equity investees		**(1.2)**		2.9
Total other comprehensive loss (OCI), net of taxes		**(41.3)**		(120.0)
Comprehensive income (loss) attributable to controlling interests and non-controlling interests, net of taxes	**$**	**6.4**	$	(49.9)
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$**	**2.3**	$	2.8
Controlling interests		**4.1**		(52.7)
	$	**6.4**	$	(49.9)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

For the three months ended March 31 *($ millions)*		**2017**		2016
Common shares *(note 10)*				
Balance, beginning of period	**$**	**3,773.4**	$	3,168.1
Shares issued for cash on exercise of options		**3.6**		1.9
Shares issued under DRIP [1]		**58.3**		26.8
Balance, end of period	**$**	**3,835.3**	$	3,196.8
Preferred shares *(note 10)*				
Balance, beginning of period	**$**	**985.1**	$	985.1
Series K issued		**293.6**		—
Deferred taxes on share issuance costs		**1.8**		—
Balance, end of period	**$**	**1,280.5**	$	985.1
Contributed surplus				
Balance, beginning of period	**$**	**17.4**	$	16.7
Share options expense		**0.3**		0.5
Exercise of share options		**(0.3)**		(0.1)
Forfeiture of share options		**—**		(0.1)
Adoption of ASU No. 2016-09 *(note 2)*		**1.1**		—
Balance, end of period	**$**	**18.5**	$	17.0
Accumulated deficit				
Balance, beginning of period	**$**	**(600.4)**	$	(435.4)
Net income applicable to controlling interests		**45.4**		67.3
Common share dividends		**(88.3)**		(72.7)
Preferred share dividends		**(13.6)**		(12.0)
Adoption of ASU No. 2016-09 *(note 2)*		**(1.1)**		—
Balance, end of period	**$**	**(658.0)**	$	(452.8)
AOCI (*note 8*)				
Balance, beginning of period	**$**	**405.1**	$	433.5
Other comprehensive loss		**(41.3)**		(120.0)
Balance, end of period	**$**	**363.8**	$	313.5
Total shareholders' equity	**$**	**4,840.1**	$	4,059.6
Non-controlling interests				
Balance, beginning of period	**$**	**34.8**	$	34.9
Net income applicable to non-controlling interests		**2.3**		2.8
Distribution by subsidiaries to non-controlling interests		**(1.4)**		(1.9)
Balance, end of period		**35.7**		35.8
Total equity	**$**	**4,875.8**	$	4,095.4

(1) Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan.

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

For the three months ended March 31 *($ millions)*	**2017**	2016
Cash from operations		
Net income after taxes	**$ 47.7**	$ 70.1
Items not involving cash:		
Depreciation and amortization	**71.5**	68.4
Accretion expenses	**2.8**	2.8
Share-based compensation	**0.3**	0.4
Deferred income tax expense (recovery) *(note 14)*	**9.9**	(4.1)
Losses (gains) on sale of assets *(note 4)*	**3.4**	(4.1)
Loss (income) from equity investments	**(14.1)**	10.7
Unrealized gains on risk management contracts *(note 9)*	**(0.9)**	(8.9)
Losses on long-term investments	**0.4**	0.2
Amortization of deferred financing costs	**6.8**	—
Other	**0.5**	0.7
Asset retirement obligations settled	**(1.2)**	(1.2)
Net distributions from (contributions to) equity investments	**6.6**	(5.9)
Changes in operating assets and liabilities *(note 15)*	**68.7**	9.0
	$ 202.4	$ 138.1
Investing activities		
Business acquisitions, net of cash acquired	**—**	(21.0)
Acquisition of property, plant and equipment	**(86.3)**	(153.2)
Acquisition of intangible assets	**(2.2)**	(0.9)
Contributions to equity investments	**(14.3)**	(6.6)
Repayment of loan from affiliate	**7.5**	—
Change in restricted cash holdings from customers	**0.9**	0.7
Payment for derivative contracts *(note 9)*	**(21.0)**	—
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**69.1**	29.2
	$ **(46.3)**	**$** (151.8)
Financing activities		
Net repayment of short-term debt	**(122.6)**	(87.1)
Issuance of long-term debt, net of debt issuance costs	**13.5**	281.9
Repayment of long-term debt	**(287.1)**	(407.5)
Dividends - common shares	**(88.0)**	(72.5)
Dividends - preferred shares	**(12.1)**	(13.1)
Distributions to non-controlling interest	**(1.4)**	(1.9)
Net proceeds from shares issued on exercise of options	**3.3**	1.8
Net proceeds from issuance of common shares	**58.3**	26.8
Net proceeds from issuance of preferred shares	**293.6**	—
Other	**(0.3)**	—
	$ (142.8)	$ (271.6)
Change in cash and cash equivalents	**13.3**	(285.3)
Effect of exchange rate changes on cash and cash equivalents	**0.1**	0.4
Cash and cash equivalents, beginning of period	**19.0**	293.4
Cash and cash equivalents, end of period	**$ 32.4**	$ 8.5

See accompanying notes to the Consolidated Financial Statements.

Notes to the Condensed Interim Consolidated Financial Statements (unaudited)

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

1. ORGANIZATION AND OVERVIEW OF THE BUSINESS

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

AltaGas, a Canadian corporation, is a North American diversified energy infrastructure company with a focus on owning and operating assets to provide clean and affordable energy to its customers. AltaGas has three business segments: Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and separation, gas transmission, gas storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas).

The Power segment includes 1,688 MW of gross generating capacity from natural gas-fired, wind, biomass and hydro assets in Canada and the United States, along with 20 MW of energy storage and an additional 1,253 MW of assets under development.

The Utilities segment is predominantly comprised of natural gas distribution rate regulated utilities in Canada and the United States. The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of, capital from the regulator-approved capital investment base.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited condensed interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP). As a result, these unaudited condensed interim Consolidated Financial Statements do not include all of the information and disclosures required in the annual Consolidated Financial Statements and should be read in conjunction with the Corporation's 2016 annual audited Consolidated Financial Statements prepared in accordance with U.S. GAAP. In management's opinion, these unaudited condensed interim Consolidated Financial Statements include all adjustments that are all of a recurring nature and necessary to present fairly the financial position of the Corporation.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by 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, 2019, the date to which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

PRINCIPLES OF CONSOLIDATION

These unaudited condensed interim Consolidated Financial Statements of AltaGas include the accounts of the Corporation and all of its wholly-owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership. Investments in unconsolidated companies that AltaGas has significant influence over, but not control, are accounted for using the equity method.

Transactions between and amongst AltaGas and its wholly-owned subsidiaries, and the proportionate interests in joint ventures or partnerships are eliminated on consolidation as required by U.S. GAAP. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “Non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries are shown as an allocation of the consolidated net income and are presented separately in "Net income applicable to non-controlling interests".

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: 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, valuation of share-based compensation, and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, 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.

SIGNIFICANT ACCOUNTING POLICIES

Except as noted below, these unaudited condensed interim Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2016 annual audited Consolidated Financial Statements.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2017, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2015-11 “Inventory: Simplifying the Measurement of Inventory”. The amendments in this ASU require an entity to measure inventory at the lower of cost and net realizable value. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-05 “Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships”. The amendments in this ASU clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-06, “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-07 “Investments - Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focuses on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. Upon adoption of this ASU, AltaGas elected as an accounting policy to account for forfeitures when they occur instead of estimating the number of awards that are expected to vest. The ASU requires this change to be adopted using the modified retrospective approach and as a result, AltaGas recorded a decrease to accumulated retained earnings of approximately $1.1 million and an increase to contributed surplus of approximately $1.1 million. The deferred tax impact was immaterial. The remaining amendments to this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, FASB issued ASU No. 2014-09 “Revenue from Contracts with Customers”, which will replace numerous requirements in U.S. GAAP, including industry-specific requirements, and provide companies with a single revenue recognition model for recognizing revenue from contracts with customers. The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 “Principal versus Agent Consideration”. The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 “Identifying Performance Obligation and Licensing”, which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 “Narrow Scope Improvements and Practical Expedients”, clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. In December 2016, FASB issued ASU No. 2016-20 “Technical Corrections and Improvements”, which makes minor technical corrections and improvements to the new revenue standard. The new revenue standard will be effective for annual and interim periods beginning on or after December 15, 2017. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A preliminary scoping exercise was completed for AltaGas’ operating segments and, while AltaGas is continuing to assess all potential impacts of the standard, AltaGas anticipates that the new standard will mostly impact the Gas and Utilities segments with regards to the timing of revenue recognition under the ASU for contracts that have take-or-pay features. AltaGas is still in the process of evaluating these impacts. AltaGas is currently progressing through contract reviews in order to identify and quantify potential differences. AltaGas is also awaiting further guidance from the AICPA Power and Utility Entities Revenue Recognition Task Force related to the income statement presentation of revenue from alternative revenue programs. The ASU permits the use of either the full retrospective or modified retrospective transition method and AltaGas currently anticipates using the modified retrospective transition method.

In January 2016, FASB issued ASU No. 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” which revises 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 amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas' financial statements.

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. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements but expects the new standard will have an impact on the Corporation's balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption.

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 periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments". The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2016, FASB issued ASU No. 2016-16 "Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory". The amendments in this ASU revise the accounting for income tax consequences on intra-entity transfer of assets by requiring an entity to recognize current and deferred tax on intra-entity transfer of assets other than inventory when the transfer occurs. The amendment in this ASU is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In November 2016, FASB issued ASU No. 2016-18 "Statement of Cash Flows: Restricted Cash". The amendments in this ASU require 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 amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU retrospectively to each period presented. Early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated cash flow statements.

In January 2017, FASB issued ASU No. 2017-01 "Business Combinations: Clarifying the Definition of a Business". The amendments in this ASU change the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis on or after the effective date. AltaGas will apply the amendments prospectively.

In January 2017, FASB issued ASU No. 2017-04 “Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment”. The ASU removes Step 2 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. An entity should adopt the amendments in this ASU for annual periods beginning after December 15, 2020, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In February 2017, FASB issued 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 clarify the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The effective date and transition requirements for the amendments in this ASU are the same as the effective date and transition requirements for ASU No. 2014-09, which is effective for fiscal years and interim periods beginning on or after December 15, 2017. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In March 2017, FASB issued 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 revise the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limit the components that are eligible for capitalization in assets to only the service cost component. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. The amendments in this ASU should be applied retrospectively for the presentation of the service cost component and the other components of net benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

3. PENDING WGL ACQUISITION

Pending Acquisition of WGL Holdings, Inc. (WGL)

On January 25, 2017, the Corporation entered into a definitive agreement (the Merger Agreement) to indirectly acquire WGL Holdings, Inc. (the WGL Acquisition). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of US$6.8 billion, including the assumption of approximately US$2.1 billion of debt as at December 31, 2016.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia. WGL has a growing midstream business with investments in natural gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeast United States with capabilities for connections to marine-based energy export opportunities via the North American Atlantic coast through the proposed Cove Point LNG terminal in Maryland being developed by a third party, currently expected to be operational in late 2017. WGL also owns contracted clean power assets, with a focus on distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 260,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

The WGL Acquisition is not subject to any financing contingency. AltaGas expects that cash to close the WGL Acquisition will be provided from a combination of the net proceeds from the $400 million private placement of subscription receipts and the $2.2 billion bought deal subscription receipt offering (including the partially exercised over-allotment option) for total gross proceeds of approximately $2.6 billion (see *Subscription Receipts* section below), subsequent offerings of senior debt, hybrid securities, equity or equity-linked securities (including Preferred Shares or convertible debentures), selected AltaGas asset sales and through a fully committed US$3.0 billion bridge facility, which would be available for 12 to 18 months following closing of the WGL Acquisition. AltaGas believes there are a number of attractive, actionable opportunities to monetize certain of its assets in a manner which supports the Corporation’s long term strategy of growing in attractive areas and maintaining a long term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. The timing of these subsequent offerings and asset sales is subject to prevailing market conditions, but are generally expected to be completed prior to the closing of the WGL Acquisition.

The WGL Acquisition is subject to certain closing conditions, including approval of WGL common shareholders and certain regulatory and government approvals, including approval by the Public Service Commission of the District of Columbia (PSC of DC), the Maryland Public Service Commission (PSC of MD), the Commonwealth of Virginia State Corporation Commission (SCC of VA), the United States Federal Energy Regulatory Commission (FERC), and the Committee on Foreign Investment in the United States (CFIUS), as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

The special meeting of WGL common shareholders to approve the WGL Acquisition is scheduled for May 10, 2017. In addition, regulatory applications were filed with the PSC of DC, the PSC of MD, the SCC of VA, FERC and CFIUS on April 24, 2017. All decisions are expected to be received in the first half of 2018.

On March 28, 2017, a class action lawsuit was filed by purported shareholders of WGL against WGL, the directors of WGL, AltaGas and Wrangler Inc. (a wholly-owned indirect subsidiary of AltaGas). The directors of AltaGas and the directors of Wrangler Inc. are not named defendants in this lawsuit. This lawsuit alleges that the preliminary proxy statement filed by WGL with the United States Securities and Exchange Commission on March 10, 2017 omitted material information with respect to the pending WGL Acquisition, rendering the proxy statement false and misleading. AltaGas believes that the claims asserted against the defendants in the lawsuit are without merit. In addition, on March 23, 2017, a class action lawsuit was filed by purported shareholders of WGL against WGL and each member of WGL's board of directors alleging that WGL and the board of directors of WGL breached fiduciary duties. AltaGas and the directors of AltaGas are not named defendants in this lawsuit.

Subscription Receipts

On February 3, 2017, the Corporation issued approximately 80.7 million subscription receipts pursuant to a private placement and public offering to partially fund the WGL Acquisition at a price of $31 each for total gross proceeds of approximately $2.5 billion. On March 3, 2017, the over-allotment option was partially exercised for an additional 3.8 million subscription receipts for gross proceeds of approximately $118 million. The sale of the additional subscription receipts pursuant to the over-allotment option brings the aggregate gross proceeds to approximately $2.6 billion. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the WGL Acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments (Dividend Equivalent Payments) per subscription receipt that are equal to dividends declared on each common share. Such Dividend Equivalent Payments will have the same record date as the related common share dividend and will be paid to holders of the subscription receipts concurrently with the payment date of each such common share dividend. The Dividend Equivalent Payments will be paid first out of any interest on the escrowed funds and then out of the escrowed funds. If the Merger Agreement is terminated after the common share dividend declaration date, but before the common share dividend record date, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the Dividend Equivalent Payment. If the Merger Agreement is terminated on a record date or following a record date but on or prior to the dividend payment date, holders will be entitled to receive the full Dividend Equivalent Payment.

The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of WGL and confirmation that the parties to the Merger Agreement are able to complete the WGL Acquisition in all material respects in accordance with the terms of the Merger Agreement, but for the payment of the purchase price, and AltaGas has available to it all other funds required to complete the WGL Acquisition. If the escrow release notice and direction is not delivered on or prior to 5:00 pm (Calgary time) on September 4, 2018, the Corporation will be required to make a termination payment equal to the aggregate issue price of such holder's subscription receipts plus any unpaid Dividend Equivalent Payments owing to such holders of subscription receipts.

4. ASSETS HELD FOR SALE

As at	March 31, 2017	December 31, 2016
Assets held for sale		
Property, plant and equipment	**$ —**	$ 67.3
Goodwill	**—**	3.4
	$ —	$ 70.7
Liabilities associated with assets held for sale		
Asset retirement obligations	**$ —**	$ 0.4
	$ —	$ 0.4

In March 2017, AltaGas completed the disposition of the Ethylene Delivery Systems and the Joffre Feedstock Pipeline transmission assets in the Gas segment to Nova Chemicals Corporation for gross proceeds of approximately $67.0 million. AltaGas recognized a pre-tax loss on disposition of approximately $3.4 million in the consolidated statement of income under the line item "Other income (loss)" for the three months ended March 31, 2017.

5. INVENTORY

As at	March 31, 2017	December 31, 2016
Natural gas held in storage	**$ 79.7**	$ 172.6
Other inventory	**49.1**	48.4
	$ 128.8	$ 221.0

6. GOODWILL

As at	March 31, 2017	December 31, 2016
Balance, beginning of period	**$ 856.0**	$ 877.3
Foreign exchange translation	**(5.1)**	(17.9)
Reclassified to assets held for sale *(note 4)*	**—**	(3.4)
Balance, end of period	**$ 850.9**	$ 856.0

7. LONG-TERM DEBT

As at	Maturity date		March 31, 2017		December 31, 2016
Credit facilities					
$1,400 million unsecured extendible revolving[a]	15-Dec-2020	**$**	**323.4**	$	377.9
US$300 million unsecured extendible revolving[b]	8-Dec-2019		**—**		—
Medium-term notes (MTNs)					
$200 million Senior unsecured - 5.49 percent	27-Mar-2017		**—**		200.0
$175 million Senior unsecured - 4.60 percent	15-Jan-2018		**175.0**		175.0
$200 million Senior unsecured - 4.55 percent	17-Jan-2019		**200.0**		200.0
$200 million Senior unsecured - 4.07 percent	1-Jun-2020		**200.0**		200.0
$350 million Senior unsecured - 3.72 percent	28-Sep-2021		**350.0**		350.0
$300 million Senior unsecured - 3.57 percent	12-Jun-2023		**300.0**		300.0
$200 million Senior unsecured - 4.40 percent	15-Mar-2024		**200.0**		200.0
$300 million Senior unsecured - 3.84 percent	15-Jan-2025		**299.9**		299.9
$100 million Senior unsecured - 5.16 percent	13-Jan-2044		**100.0**		100.0
$300 million Senior unsecured - 4.50 percent	15-Aug-2044		**299.8**		299.8
$350 million Senior unsecured - 4.12 percent	7-Apr-2026		**349.8**		349.8
US$125 million Senior unsecured - floating[c]	17-Apr-2017		**166.4**		167.8
SEMCO long-term debt					
US$300 million SEMCO Senior secured - 5.15 percent[d]	21-Apr-2020		**399.3**		402.8
US$82 million CINGSA Senior secured - 4.48 percent[e]	2-Mar-2032		**93.6**		97.5
Debenture notes					
PNG RoyNat Debenture - 3.40 percent[f]	15-Sep-2017		**7.1**		7.4
PNG 2018 Series Debenture - 8.75 percent[f]	15-Nov-2018		**8.0**		8.0
PNG 2025 Series Debenture - 9.30 percent[f]	18-Jul-2025		**13.5**		13.5
PNG 2027 Series Debenture - 6.90 percent[f]	2-Dec-2027		**14.5**		14.5
CINGSA capital lease - 3.50 percent	1-May-2040		**0.6**		0.6
CINGSA capital lease - 4.48 percent	4-Jun-2068		**0.2**		0.2
		$	**3,501.1**	$	3,764.7
Less debt issuance costs			**(13.7)**		(14.4)
			3,487.4		3,750.3
Less current portion			**(356.6)**		(383.4)
		$	**3,130.8**	$	3,366.9

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made.

(b) Borrowings on the facility can be by way of U.S. base-rate loans, U.S. prime loans, LIBOR loans or letters of credit.

(c) The notes carry a floating rate coupon of three months LIBOR plus 0.85 percent.

(d) Collateral for the US$ MTNs is certain SEMCO assets.

(e) Collateral for the CINGSA Senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

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

8. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Available-for-sale	Defined benefit pension and PRB plans	Hedge net investments	Translation foreign operations	Equity Investee	Total
Opening balance, January 1, 2017	**$ 19.8**	**$ (11.3)**	**$ (135.6)**	**$ 526.3**	**$ 5.9**	**$ 405.1**
OCI before reclassification	**(17.4)**	**—**	**3.0**	**(24.2)**	**(1.2)**	**(39.8)**
Amounts reclassified from OCI	**—**	**0.2**	**—**	**—**	**—**	**0.2**
Current period OCI (pre-tax)	**(17.4)**	**0.2**	**3.0**	**(24.2)**	**(1.2)**	**(39.6)**
Income tax on amounts retained in AOCI	**—**	**—**	**(1.6)**	**—**	**—**	**(1.6)**
Income tax on amounts reclassified to earnings	**—**	**(0.1)**	**—**	**—**	**—**	**(0.1)**
Net current period OCI	**(17.4)**	**0.1**	**1.4**	**(24.2)**	**(1.2)**	**(41.3)**
Ending balance, March 31, 2017	**$ 2.4**	**$ (11.2)**	**$ (134.2)**	**$ 502.1**	**$ 4.7**	**$ 363.8**
Opening balance, January 1, 2016	$ (2.4)	$ (9.6)	$ (169.6)	$ 610.5	$ 4.6	$ 433.5
OCI before reclassification	3.7	—	61.6	(177.3)	2.9	(109.1)
Amounts reclassified from OCI	—	0.2	—	—	—	0.2
Current period OCI (pre-tax)	3.7	0.2	61.6	(177.3)	2.9	(108.9)
Income tax on amounts retained in AOCI	(0.5)	—	(10.5)	—	—	(11.0)
Income tax on amounts reclassified to earnings	—	(0.1)	—	—	—	(0.1)
Net current period OCI	3.2	0.1	51.1	(177.3)	2.9	(120.0)
Ending balance, March 31, 2016	$ 0.8	$ (9.5)	$ (118.5)	$ 433.2	$ 7.5	$ 313.5

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item	Three months ended March 31 2017	2016
Defined benefit pension and PRB plans	Operating and administrative expense	**$ 0.2**	$ 0.2
Deferred income taxes	Income tax expenses – deferred	**(0.1)**	(0.1)
		$ 0.1	$ 0.1

9. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation’s financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, certain long-term investments and other assets, accounts payable and accrued liabilities, dividends payable, short-term and long-term debt and certain other current and long-term liabilities.

Fair Value Hierarchy

AltaGas 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. Included in this category are publicly traded shares valued at the closing price as at the balance sheet date.

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. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

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

The following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Cash and cash equivalents, Accounts receivable, Accounts payable, Short-term debt and Dividends payable - the carrying amounts approximate fair value because of the short maturity of these instruments.

Current portion of long-term debt, Long-term debt and Other long-term liabilities - the fair value of these liabilities has been estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

Risk management assets and liabilities - the fair values of power, natural gas and NGL derivative contracts were calculated using discounted cash flow analysis based upon forward prices from published sources for the relevant period. The fair value of foreign exchange derivative contracts was calculated using quoted market rates. The fair value of foreign exchange option contracts was calculated using a variation of the Black-Scholes pricing model.

	March 31, 2017				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Cash and cash equivalents	**$ 32.4**	**$ 32.4**	**$ —**	**$ —**	**$ 32.4**
Risk management assets - current	**40.5**	**—**	**40.5**	**—**	**40.5**
Risk management assets - non-current	**41.6**	**—**	**41.6**	**—**	**41.6**
Long-term investments and other assets [(a)]	**87.6**	**31.6**	**56.1**	**—**	**87.7**
	$ 202.1	**$ 64.0**	**$ 138.2**	**$ —**	**$ 202.2**
Financial liabilities					
Risk management liabilities - current	**$ 23.5**	**$ —**	**$ 23.5**	**$ —**	**$ 23.5**
Risk management liabilities - non-current	**15.4**	**—**	**15.4**	**—**	**15.4**
Current portion of long-term debt	**356.6**	**—**	**360.5**	**—**	**360.5**
Long-term debt	**3,130.8**	**—**	**3,283.8**	**—**	**3,283.8**
Other current liabilities [(b)]	**13.3**	**—**	**13.5**	**—**	**13.5**
Other long-term liabilities [(b)]	**148.6**	**—**	**150.4**	**—**	**150.4**
	$ 3,688.2	**$ —**	**$ 3,847.1**	**$ —**	**$ 3,847.1**

(a) Excludes non-financial assets.

(b) Excludes non-financial liabilities.

	December 31, 2016				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Cash and cash equivalents	$ 19.0	$ 19.0	$ —	$ —	$ 19.0
Risk management assets - current	40.4	—	40.4	—	40.4
Risk management assets - non-current	24.1	—	24.1	—	24.1
Long-term investments and other assets [(a)]	113.0	49.4	63.6	—	113.0
	$ 196.5	$ 68.4	$ 128.1	$ —	$ 196.5
Financial liabilities					
Risk management liabilities - current	$ 32.9	$ —	$ 32.9	—	$ 32.9
Risk management liabilities - non-current	12.6	—	12.6	—	12.6
Current portion of long-term debt	383.4	—	385.3	—	385.3
Long-term debt	3,366.9	—	3,500.9	—	3,500.9
Other current liabilities [(b)]	22.3	—	22.0	—	22.0
Other long-term liabilities [(b)]	152.8	—	152.4	—	152.4
	$ 3,970.9	$ —	$ 4,106.1	$ —	$ 4,106.1

(a) Excludes non-financial assets.

(b) Excludes non-financial liabilities.

Summary of Unrealized Gains (Losses) on Risk Management Contracts Recognized in Net Income

Three months ended March 31	**2017**	2016
Natural gas	**$ (1.8)**	$ (0.9)
Storage optimization	**2.4**	(2.4)
NGL frac spread	**7.5**	—
Power	**(0.4)**	12.1
Foreign exchange	**(6.8)**	(0.1)
Embedded derivative	**—**	0.2
	$ 0.9	$ 8.9

Offsetting of Derivative Assets and Derivative Liabilities

Certain AltaGas risk management contracts are subject to master netting arrangements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities.

	March 31, 2017		
Risk management assets [(a)]	**Gross amounts of recognized assets/liabilities**	**Gross amounts offset in balance sheet**	**Net amounts presented in balance sheet**
Natural gas	**$ 22.3**	**$ (4.3)**	**$ 18.0**
NGL frac spread	**1.1**	**(0.5)**	**0.6**
Power	**49.1**	**(0.3)**	**48.8**
Foreign exchange	**14.7**	**—**	**14.7**
	$ 87.2	**$ (5.1)**	**$ 82.1**
Risk management liabilities [(b)]			
Natural gas	**$ 20.5**	**$ (4.3)**	**$ 16.2**
Storage optimization	**0.3**	**—**	**0.3**
NGL frac spread	**5.9**	**(0.5)**	**5.4**
Power	**17.3**	**(0.3)**	**17.0**
	$ 44.0	**$ (5.1)**	**$ 38.9**

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $40.5 million and risk management assets (non-current) balance of $41.6 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $23.5 million and risk management liabilities (non-current) balance of $15.4 million.

	December 31, 2016		
Risk management assets [(a)]	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Net amounts presented in balance sheet
Natural gas	$ 20.1	$ (2.9)	$ 17.2
Storage optimization	0.7	(0.7)	—
NGL frac spread	3.4	—	3.4
Power	43.5	—	43.5
Foreign exchange	1.8	(1.4)	0.4
	$ 69.5	$ (5.0)	$ 64.5
Risk management liabilities [(b)]			
Natural gas	$ 16.5	$ (2.9)	$ 13.6
Storage optimization	3.5	(0.7)	2.8
NGL frac spread	15.7	—	15.7
Power	13.4	—	13.4
Foreign exchange	1.4	(1.4)	—
	$ 50.5	$ (5.0)	$ 45.5

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $40.4 million and risk management assets (non-current) balance of $24.1 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $32.9 million and risk management liabilities (non-current) balance of $12.6 million.

Notional Summary

The following table presents the notional quantity outstanding related to the Corporation's commodity contracts:

	March 31, 2017	December 31, 2016
Natural Gas		
Sales	**75,826,039 GJ**	63,209,420 GJ
Purchases	**59,085,533 GJ**	58,913,082 GJ
Swaps	**2,224,375 GJ**	474,037 GJ
NGL Frac Spread		
Propane swaps	**1,101,122 Bbl**	1,330,063 Bbl
Butane swaps	**—**	49,500 Bbl
Crude oil swaps	**277,750 Bbl**	302,710 Bbl
Natural gas swaps	**6,314,550 GJ**	7,639,175 GJ
Power		
Sales	**2,662,238 MWh**	2,671,748 MWh
Purchases	**167,140 MWh**	217,520 MWh
Swaps	**1,675,733 MWh**	1,472,040 MWh

Foreign Exchange

AltaGas hedges its foreign operations by designating its U.S. dollar-denominated debt as a net investment hedge. As at March 31, 2017, AltaGas designated US$317.0 million of outstanding debt as a net investment hedge (December 31, 2016 - US$301.0 million).

In addition, to mitigate the foreign exchange risks associated with the cash purchase price of WGL, AltaGas has entered into foreign currency option contracts with an aggregate notional value of US$500.0 million. These foreign currency option contracts did not qualify for hedge accounting.

10. SHAREHOLDERS' EQUITY

Authorization

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

Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP or the Plan)

The Plan consists of three components: a Premium Dividend™ component, a Dividend Reinvestment component and an Optional Cash Purchase component.

The Plan provides eligible holders of common shares with the opportunity to, at their election, either: (1) reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 3 percent discount to the average market price (as defined below) of the common shares on the applicable dividend payment date (the Dividend Reinvestment component of the Plan); or (2) reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 3 percent discount to the average market price (as defined below) on the applicable dividend payment date and have these additional common shares of AltaGas exchanged for a cash payment equal to 101 percent of the reinvested amount (the Premium Dividend™ component of the Plan).

In addition, the Plan provides shareholders who are enrolled in the Dividend Reinvestment component of the Plan with the opportunity to purchase new common shares at the average market price (with no discount) on the applicable dividend payment date (the Optional Cash Purchase component of the Plan).

Each of the components of the Plan are subject to prorating and other limitations on availability of new common shares in certain events. The "average market price", in respect of a particular dividend payment date, refers to the arithmetic average (calculated

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to four decimal places) of the daily volume weighted average trading prices of common shares on the Toronto Stock Exchange for the trading days on which at least one board lot of common shares is traded during the 10 business days immediately preceding the applicable dividend payment date. Such trading prices will be appropriately adjusted for certain capital changes (including common share subdivisions, common share consolidations, certain rights offerings and certain dividends). Shareholders resident outside of Canada are not entitled to participate in the Premium Dividend™ component of the Plan. Shareholders resident outside of Canada (other than the U.S.) may participate in the Dividend Reinvestment component or the Optional Cash Purchase Component of the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that AltaGas is satisfied in its sole discretion, that such laws do not subject the Plan or AltaGas to additional legal or regulatory requirements.

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2016	146,281,247	$	3,168.1
Shares issued on public offering, net of issuance costs	14,685,000		422.2
Shares issued for cash on exercise of options	337,750		9.3
Deferred taxes on share issuance cost	—		0.2
Shares issued under DRIP	5,602,836		173.6
December 31, 2016	166,906,833		3,773.4
Shares issued for cash on exercise of options	123,125		3.6
Shares issued under DRIP	1,878,134		58.3
Issued and outstanding at March 31, 2017	**168,908,092**	**$**	**3,835.3**

Preferred Shares

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2016	5,511,220	$	135.0
December 31, 2016	5,511,220		135.0
Issued and outstanding at March 31, 2017	**5,511,220**	**$**	**135.0**

Preferred Shares Series B Issued and Outstanding	Number of shares		Amount
January 1, 2016	2,488,780	$	60.9
December 31, 2016	2,488,780		60.9
Issued and outstanding at March 31, 2017	**2,488,780**	**$**	**60.9**

Preferred Shares Series C Issued and Outstanding	Number of shares		Amount
January 1, 2016	8,000,000	$	200.6
December 31, 2016	8,000,000		200.6
Issued and outstanding at March 31, 2017	**8,000,000**	**$**	**200.6**

Preferred Shares Series E Issued and Outstanding	Number of shares		Amount
January 1, 2016	8,000,000	$	195.8
December 31, 2016	8,000,000		195.8
Issued and outstanding at March 31, 2017	**8,000,000**	**$**	**195.8**

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Preferred Shares Series G Issued and Outstanding	Number of shares		Amount
January 1, 2016	8,000,000	$	196.1
December 31, 2016	8,000,000		196.1
Issued and outstanding at March 31, 2017	**8,000,000**	**$**	**196.1**

Preferred Shares Series I Issued and Outstanding	Number of shares		Amount
January 1, 2016	8,000,000	$	196.7
December 31, 2016	8,000,000		196.7
Deferred taxes on share issuance costs	—		0.1
Issued and outstanding at March 31, 2017	**8,000,000**	**$**	**196.8**

Preferred Shares Series K Issued and Outstanding	Number of shares		Amount
January 1, 2016 and December 31, 2016	—	$	—
Shares issued	12,000,000		300.0
Share issuance costs, net of taxes	—		(4.7)
Issued and outstanding at March 31, 2017	**12,000,000**	**$**	**295.3**

Preferred Shares

On February 22, 2017, AltaGas issued 12,000,000 cumulative 5-Year minimum rate reset redeemable preferred shares, Series K, at a price of $25 per Series K preferred share for aggregate gross proceeds of $300.0 million on a bought deal basis. Holders of the Series K preferred shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding March 31, 2022 at an annual rate of 5.0 percent, payable on the last day of March, June, September and December, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payment is payable on June 30, 2017 in the amount of $0.4384 per Series K Preferred Share. The dividend rate will reset on March 31, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.8 percent, provided that, in any event, such rate shall not be less than 5.0 percent per annum. The Series K preferred shares are redeemable by AltaGas, at its option, on March 31, 2022 and on March 31 of every fifth year thereafter.

Holders of Series K preferred shares will have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series L, subject to certain conditions, on March 31, 2022 and on March 31 every fifth year thereafter. Holders of Series L preferred shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 3.8 percent, as and when declared by the Board of Directors of AltaGas.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at March 31, 2017, 12,211,548 shares were reserved for issuance under the plan. As at March 31, 2017, options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at March 31, 2017, unexpensed fair value of share option compensation cost associated with future periods was $2.3 million (December 31, 2016 - $1.0 million).

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

As at	**March 31, 2017**			December 31, 2016		
	Options outstanding			Options outstanding		
	Number of options		**Exercise price[(a)]**	Number of options		Exercise price[(a)]
Share options outstanding, beginning of period	**4,119,386**	**$**	**32.39**	4,559,261	$	32.02
Granted	**712,500**		**31.05**	89,500		31.45
Exercised	**(123,125)**		**26.32**	(337,750)		25.28
Forfeited	**(29,500)**		**40.09**	(191,625)		35.60
Share options outstanding, end of period	**4,679,261**	**$**	**32.30**	4,119,386	$	32.39
Share options exercisable, end of period	**3,197,008**	**$**	**30.85**	3,279,133	$	30.56

(a) Weighted average.

As at March 31, 2017, the aggregate intrinsic value of the total options exercisable was $9.5 million (December 31, 2016 - $16.5 million), the total intrinsic value of options outstanding was $9.5 million (December 31, 2016 - $16.8 million) and the total intrinsic value of options exercised was $0.7 million (December 31, 2016 - $2.6 million).

The following table summarizes the employee share option plan as at March 31, 2017:

	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
$14.24 to $18.00	168,250	$	15.16	2.02	168,250	$	15.16	2.02
$18.01 to $25.08	569,475		21.26	3.18	569,475		21.26	3.18
$25.09 to $50.89	3,941,536		34.63	4.71	2,459,283		34.15	4.59
	4,679,261	**$**	**32.30**	**4.43**	**3,197,008**	**$**	**30.85**	**4.21**

Medium Term Incentive Plan (MTIP) and Deferred Share Unit Plan (DSUP)

AltaGas has a MTIP for employees and executive officers, which includes restricted units (RUs) and performance units (PUs) with vesting periods between 36 to 44 months from the grant date. In addition, AltaGas has a DSUP, which allows granting of deferred share units (DSUs) to directors, officers and employees. AltaGas currently intends only to offer DSUs as a form of director compensation. DSUs granted under the DSUP vest immediately but settlement of the DSUs occur when the individual ceases to be a director.

PUs, RUs, and DSUs	**March 31, 2017**	December 31, 2016
(number of units)		
Balance, beginning of period	**364,839**	409,037
Granted	**171,103**	91,288
Vested and paid out	**(9,269)**	(136,359)
Forfeited	**(1,339)**	(13,565)
Units in lieu of dividends	**5,029**	14,438
Outstanding, end of period	**530,363**	364,839

For the three months ended March 31, 2017, the compensation expense recorded for the MTIP and DSUP was $1.4 million (2016 – $1.4 million). As at March 31, 2017, the unrecognized compensation expense relating to the remaining vesting period was $16.3 million (December 31, 2016 - $12.4 million) and is expected to be recognized over the vesting period.

11. NET INCOME PER COMMON SHARE

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

Three months ended March 31		**2017**		2016
Numerator:				
Net income applicable to controlling interests	**$**	**45.4**	$	67.3
Less: Preferred share dividends		**(13.6)**		(12.0)
Net income applicable to common shares	**$**	**31.8**	$	55.3
Denominator:				
(millions)				
Weighted average number of common shares outstanding		**167.9**		146.8
Dilutive equity instruments[(a)]		**0.4**		0.4
Weighted average number of common shares outstanding - diluted		**168.3**		147.2
Basic net income per common share	**$**	**0.19**	$	0.38
Diluted net income per common share	**$**	**0.19**	$	0.38

(a) Includes all options that have a strike price lower than the average share price of AltaGas' common shares during the periods noted.

For the three months ended March 31, 2017, 2.1 million of share options (2016 – 2.3 million) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

12. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

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

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2017 to 2033, 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.

In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines (CT) at the Blythe facility over 116,000 equivalent operating hour per CT, or 20 years, whichever comes first. As at March 31, 2017, approximately $215.5 million is expected to be paid over the next 18 years, of which $58.9 million is expected to be paid over the next five years.

In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwestern Ontario. AltaGas is obligated to pay approximately $3.5 million per annum over the term of the contract for storage services.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $9.0 million over the next 5 years.

Guarantees

On October 2014, Heritage Gas Limited, a wholly-owned subsidiary of AltaGas, entered into a throughput contract with 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 Atlantic Bridge Project and it will expire 15 years thereafter. AltaGas has two guarantees outstanding that total US$91.7 million to stand by all payment obligations under the transportation agreement.

Contingencies

AltaGas and its subsidiaries are 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 Corporation does not believe that the resolution of such claims and actions will have a material impact on the Corporation's consolidated financial position or results of operations.

13. PENSION PLANS AND RETIREE BENEFITS

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:

	Three months Ended March 31, 2017					
	Canada		**United States**		**Total**	
	Defined Benefit	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**
Current service cost	**$ 2.0**	**$ 0.2**	**$ 1.8**	**$ 0.4**	**$ 3.8**	**$ 0.6**
Interest cost	**1.4**	**0.2**	**3.0**	**0.7**	**4.4**	**0.9**
Expected return on plan assets	**(1.5)**	**(0.1)**	**(4.1)**	**(1.2)**	**(5.6)**	**(1.3)**
Amortization of net actuarial loss	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Amortization of regulatory asset	**0.3**	**—**	**1.6**	**(0.1)**	**1.9**	**(0.1)**
Net benefit cost recognized	**$ 2.4**	**$ 0.3**	**$ 2.3**	**$ (0.2)**	**$ 4.7**	**$ 0.1**

	Three months Ended March 31, 2016					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost	$ 1.7	$ 0.2	$ 1.9	$ 0.5	$ 3.6 $	0.7
Interest cost	1.4	0.2	3.1	1.0	4.5	1.2
Expected return on plan assets	(1.3)	—	(3.9)	(1.2)	(5.2)	(1.2)
Amortization of net actuarial loss	0.2	—	—	—	0.2	—
Amortization of regulatory asset	0.3	—	1.6	0.2	1.9	0.2
Net benefit cost recognized	$ 2.3	$ 0.4	$ 2.7	$ 0.5	$ 5.0	0.9

14. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2017 was approximately 30.9 percent (2016 – 7.8 percent). The increase in the effective tax rate for the three months ended March 31, 2017 was mainly attributable to the tax recovery related to the sale of assets to Tidewater Midstream and Infrastructure Ltd. in the first quarter of 2016 and a portion of transaction costs incurred on the pending WGL Acquisition in the first quarter of 2017 not being deductible for tax.

15. SUPPLEMENTAL CASH FLOW INFORMATION

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

Three months ended March 31		**2017**		2016
Source (use) of cash:				
Accounts receivable	**$**	**17.1**	$	55.2
Inventory		**90.3**		36.1
Other current assets		**6.7**		—
Regulatory assets (current)		**(1.0)**		(6.2)
Accounts payable and accrued liabilities		**(4.9)**		(51.4)
Customer deposits		**(12.8)**		(11.1)
Regulatory liabilities (current)		**(7.2)**		(0.6)
Other current liabilities		**(3.6)**		(2.8)
Other operating assets and liabilities		**(15.9)**		(10.2)
Changes in operating assets and liabilities	**$**	**68.7**	$	9.0

The following cash payments have been included in the determination of earnings:

Three months ended March 31		**2017**		2016
Interest paid (net of capitalized interest)	**$**	**52.4**	$	47.8
Income taxes paid	**$**	**11.3**	$	12.4

16. SEASONALITY

The utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales increase during the winter resulting in stronger first and fourth quarter results and weaker second and third quarter results.

The power generation at the run-of-river hydro-facilities Forrest Kerr, Volcano Creek, and McLymont Creek occurs substantially from mid second quarter through early fourth quarter, resulting in weaker results in the first and fourth quarters.

17. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Corporation's four reporting segments:

Gas	– NGL processing and extraction plants; – transmission pipelines to transport natural gas and NGL; – natural gas gathering lines and field processing facilities; – purchase and sale of natural gas, including to commercial and industrial users; – natural gas storage facilities; – liquefied petroleum gas (LPG) terminal currently under construction; – natural gas and NGL marketing; and – equity investment in Petrogas, a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents.
Power	– natural gas-fired, wind, biomass and hydro power generation assets, whereby outputs are generally sold under long term power purchase agreements, both operational and under development; – energy storage; and – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
Corporate	– the cost of providing corporate services, financing and general corporate overhead, investments in certain public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

The following tables show the composition by segment:

	Three months ended March 31, 2017					
	Gas	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**[(a)]	**Total**
Revenue	**$ 301.5**	**$ 132.2**	**$ 414.8**	**$ 0.9**	**$ (79.1)**	**$ 770.3**
Unrealized gains (losses) on risk management	**—**	**—**	**(0.3)**	**1.2**	**—**	**0.9**
Cost of sales	**(204.1)**	**(61.8)**	**(244.9)**	**—**	**76.7**	**(434.1)**
Operating and administrative	**(41.8)**	**(23.2)**	**(56.2)**	**(41.4)**	**2.5**	**(160.1)**
Accretion expenses	**(1.0)**	**(1.8)**	**—**	**—**	**—**	**(2.8)**
Depreciation and amortization	**(16.5)**	**(30.8)**	**(20.8)**	**(3.4)**	**—**	**(71.5)**
Income from equity investments	**11.2**	**2.3**	**0.6**	**—**	**—**	**14.1**
Other income (loss)	**(3.4)**	**—**	**0.6**	**0.8**	**(0.1)**	**(2.1)**
Foreign exchange gains	**—**	**—**	**—**	**0.3**	**—**	**0.3**
Interest expense	**—**	**—**	**—**	**(46.0)**	**—**	**(46.0)**
Income (loss) before income taxes	**$ 45.9**	**$ 16.9**	**$ 93.8**	**$ (87.6)**	**$ —**	**$ 69.0**
Net additions (reductions) to:						
Property, plant and equipment[(b)]	**$ (21.6)**	**$ 7.0**	**$ 16.4**	**$ 0.2**	**$ —**	**$ 2.0**
Intangible assets	**$ 0.5**	**$ 0.2**	**$ 0.4**	**$ 0.9**	**$ —**	**$ 2.0**

(a) Intersegment transactions are recorded at market value.

(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash flow due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Three months ended March 31, 2016					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[(a)]	Total
Revenue	$ 238.9	$ 122.8	$ 384.0	$ 1.8	$ (145.9)	$ 601.6
Unrealized gains on risk management	—	—	—	8.9	—	8.9
Cost of sales	(163.8)	(47.9)	(219.5)	—	142.5	(288.7)
Operating and administrative	(41.9)	(26.0)	(57.3)	(9.9)	3.5	(131.6)
Accretion expenses	(1.0)	(1.8)	—	—	—	(2.8)
Depreciation and amortization	(15.0)	(27.3)	(22.4)	(3.7)	—	(68.4)
Income (loss) from equity investments	0.7	(12.0)	0.6	—	—	(10.7)
Other income	4.0	—	0.2	0.3	(0.1)	4.4
Foreign exchange loss	—	—	—	(0.6)	—	(0.6)
Interest expense	—	—	—	(36.1)	—	(36.1)
Income (loss) before income taxes	$ 21.9	$ 7.8	$ 85.6	$ (39.3)	$ —	$ 76.0
Net additions (reductions) to:						
Property, plant and equipment[(b)]	$ 51.8	11.2	16.1	0.8	—	$ 79.9
Intangible assets	$ 0.2	0.1	0.2	0.3	—	$ 0.8

(a) Intersegment transactions are recorded at market value.

(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash flow due to classification of business acquisition and foreign exchange changes on U.S. assets.

The following table shows goodwill and total assets by segment:

	Gas	Power	Utilities	Corporate	Total
As at March 31, 2017					
Goodwill	**$ 152.9**	**$ —**	**$ 698.0**	**$ —**	**$ 850.9**
Segmented assets	**$ 2,797.7**	**$ 3,470.5**	**$ 3,464.4**	**$ 311.6**	**$ 10,044.2**
As at December 31, 2016					
Goodwill	$ 152.9	$ —	$ 703.1	$ —	$ 856.0
Segmented assets	$ 2,826.3	$ 3,501.3	$ 3,586.4	$ 286.6	$ 10,200.6

18. SUBSEQUENT EVENTS

Subsequent events have been reviewed through April 25, 2017, the date on which these unaudited condensed interim Consolidated Financial Statements were issued.

Subsequent to quarter end, AltaGas entered into additional foreign currency option contracts with an aggregate notional value of US$675.0 million.

Supplementary Quarterly Operating Information

(unaudited)

	Q1-17	Q4-16	Q3-16	Q2-16	Q1-16
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	**1,404**	1,337	1,275	1,083	1,222
Extraction volumes (Bbls/d)(1)(2)	**71,958**	69,687	65,509	58,065	64,408
Frac spread - realized ($/Bbl)(1)(3)	**10.56**	6.11	6.29	10.00	8.22
Frac spread - average spot price ($/Bbl)(1)(4)	**17.26**	8.40	6.29	10.62	8.22
POWER					
Renewable power sold (GWh)	**148**	196	670	544	142
Conventional power sold (GWh)	**385**	374	587	293	698
Renewable capacity factor (%)	**9.5**	18.8	70.2	56.8	10.5
Contracted conventional availability factor (%)(5)	**96.0**	99.8	99.3	92.4	97.6
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	**13.5**	10.8	3.2	4.8	12.3
Natural gas deliveries - transportation (PJ)(6)	**1.9**	1.5	1.1	1.5	1.8
U.S. utilities					
Natural gas deliveries end use (Bcf) (6)	**30.2**	22.8	5.4	10.3	28.2
Natural gas deliveries transportation (Bcf)(6)	**15.4**	14.2	11.0	11.8	14.2
Service sites(7)	**576,829**	574,875	568,628	568,606	570,681
Degree day variance from normal - AUI (%)(8)	**(2.2)**	(0.6)	(8.4)	(28.0)	(18.5)
Degree day variance from normal - Heritage Gas (%)(8)	**(1.9)**	(1.0)	(7.4)	3.6	(6.9)
Degree day variance from normal - SEMCO Gas (%)(9)	**(11.8)**	(6.1)	(57.6)	11.8	(8.5)
Degree day variance from normal - ENSTAR (%)(9)	**9.6**	(1.4)	(36.1)	(26.4)	(21.0)

(1) Average for the period.

(2) Includes Harmattan NGL processed on behalf of customers.

(3) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.

(4) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac exposed volumes for the period.

(5) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.

(6) Petajoule (PJ) is one million gigajoules (GJ). Bcf is one billion cubic feet.

(7) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas, and U.S. Utilities, including transportation and non-regulated business lines.

(8) A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. 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 British Columbia Utilities Commission (BCUC) has approved a rate stabilization mechanism for its residential and small commercial customers.

(9) A degree day for U.S. Utilities is a measure of coldness, determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Energy Gas Company and during the prior 10 years for ENSTAR.

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
MMBTU	million British thermal unit
PJ	petajoule
US$	United States dollar

ABOUT ALTAGAS

AltaGas is an energy infrastructure company with a focus on natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

For further information contact:

Investment Community
1-877-691-7199
investor.relations@altagas.ca