NEWS RELEASE
ALTAGAS LTD. REPORTS STRONG THIRD QUARTER 2017 RESULTS AND INCREASES DIVIDEND BY 4.3 PERCENT

Calgary, Alberta (October 19, 2017)

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

- Achieved record third quarter normalized EBITDA[1] of $190 million, an increase of approximately 8 percent over the third quarter of 2016;
- Achieved normalized funds from operations[1] of $143 million in the third quarter;
- Increased common share dividend by $0.0075 per share per month to $2.19 per share annualized (a 4.3 percent increase), beginning with the December 15, 2017 payment;
- Commissioned Townsend 2A on October 1, 2017. The 99 Mmcf/d shallow-cut natural gas processing facility was completed ahead of schedule and under budget;
- Moved the target commercial on-stream date up to early December 2017 from first quarter 2018 for the North Pine NGL Separation Facility, with the estimated project capital cost under budget;
- Significantly advanced construction on the Ridley Island Propane Export Terminal (RIPET);
- Received approval from the Michigan Public Service Commission (MPSC) to construct, own, and operate the Marquette Connector Pipeline (MCP); and
- Launched first phase of asset sale process, which includes the Blythe and Tracy Facilities in California, together with smaller non-core assets.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported that normalized EBITDA in the third quarter of 2017 increased $14 million to $190 million, compared to the same quarter in 2016. Normalized funds from operations were $143 million ($0.83 per share) for the third quarter of 2017, compared to $137 million ($0.84 per share) in the same period of 2016. On a U.S. GAAP basis, net income applicable to common shares for the third quarter of 2017 was $18 million ($0.10 per share) compared to $46 million ($0.28 per share) in the third quarter of 2016. Normalized net income[1] was $48 million ($0.28 per share) for the third quarter of 2017, compared to $38 million ($0.23 per share) in the same period of 2016.

"Each of our three business segments continue to perform extremely well, delivering consistent strong results and keeping us on track to deliver low double digit percentage growth in normalized EBITDA and high single digit percentage growth in normalized funds from operations over 2016," said David Harris, President and Chief Executive Officer of AltaGas. "Our strong operational and financial performance and our dividend increase underscore our commitment to our shareholders."

Year-to-date, all three of AltaGas' business segments have generated increased results over the same period in 2016. AltaGas remains committed to its strategy of growing each business segment in a balanced long-term manner and is actively pursuing growth opportunities in each segment.

Gas

AltaGas has significantly advanced its northeast British Columbia and energy export strategies. The 99 Mmcf/d Townsend 2A shallow-cut natural gas processing facility was commissioned on October 1, 2017, slightly ahead of schedule and approximately $5 million under budget, with a final cost of approximately $125 million. AltaGas and Painted Pony Energy Ltd. (Painted Pony) have entered into 20-year take-or-pay agreements in respect of Townsend 2A and the incremental field compression equipment, with the take-or-pay expected to take full effect on January 1, 2018. Volumes are expected to progressively ramp up through the fourth quarter of 2017 to the first quarter of 2018.

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

The 10,000 Bbls/d first train of the North Pine NGL Separation Facility is ahead of its original schedule and is expected to come online early in December 2017. AltaGas has entered into long-term supply agreements with Painted Pony for a portion of the total capacity, which includes dedication of all of Painted Pony's NGL produced at the Townsend and Blair Creek facilities. The remaining capacity is expected to be filled with NGL produced in the area.

At RIPET crews are currently working to pour the concrete outer wall for the propane tank, with the fourth of eight concrete pours underway and the final pour scheduled near the end of 2017. Fabrication for the inner steel tank roof is also underway and installation of the inner steel tank will begin. The balance of plant fabrication and civil work is on track and the first modules are scheduled to arrive in the first quarter of 2018. RIPET is expected to be in service by the first quarter of 2019. The construction cost of RIPET is estimated to be approximately $450 to $500 million (for 100 percent of the project).

In addition to the projects that are currently under construction, AltaGas continues to have positive and ongoing discussions with producers for additional processing and gathering capacity in various parts of both the northeast British Columbia and Alberta Montney resource plays. In particular, AltaGas is in discussions with a number of producers in the Gordondale, Alberta area to expand the Gordondale gas gathering system to fill capacity at the Gordondale Facility and potentially expand the facility over time.

Utilities

On August 23, the MPSC approved SEMCO Gas' application to construct, own and operate the MCP. The MCP is a 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. AltaGas will be proceeding with engineering and property acquisitions, expected to begin in early 2018, and construction is expected to begin in 2019, with an anticipated in-service date in mid-2020. The project is estimated to cost between US$135 to $140 million.

AltaGas continues to invest in each of its Utilities primarily through system betterment opportunities as well as the addition of new customers. In addition, the September 22, 2017 rate case decision from the Regulatory Commission of Alaska on ENSTAR's 2015 test-year rate case permanently implemented the rate increases from the third quarter of 2016 and a further permanent rate increase is anticipated to be implemented by December 2017.

Power

AltaGas continues to pursue energy storage and solar opportunities, driven by the needs of load serving entities, to enhance the value of its California power position. AltaGas' greenfield and brownfield development sites throughout California are well suited for renewable or energy storage, or both renewable and energy storage projects. AltaGas expects that its greenfield and brownfield development sites could attract multi-year power purchase agreements through either the standard request for proposal (RFP) process or bilateral discussions.

As it relates to the current development project Sonoran, AltaGas continues to have bilateral discussions with public owned utilities, investor owned utilities, community choice aggregators, 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 region.

Strategic Pending Acquisition of WGL Holdings Inc. (WGL Acquisition)

On January 25, 2017, AltaGas announced it had entered into a merger agreement (the "Merger Agreement") to indirectly acquire WGL Holdings, Inc. (WGL), a diversified energy infrastructure company (the "WGL Acquisition"). The combination will bring together high quality, low-risk, long-lived infrastructure assets in North America with approximately $5 billion in secured growth projects and approximately $2 billion of growth opportunities through 2021 which are in advanced stages of development.

The WGL Acquisition is expected to provide material accretion to earnings per share (8 - 10 percent) and to normalized funds from operations per share[1] (15 - 20 percent) on average through 2021. Starting with the first full year (2019), the WGL Acquisition is also expected to support visible dividend growth of 8 - 10 percent per annum through 2021, while allowing AltaGas to maintain a conservative payout of normalized funds from operations.

On April 24, 2017, AltaGas filed regulatory applications with the public utility commissions in Maryland, Virginia and Washington D.C. On the same date, AltaGas and WGL also filed their voluntary Joint Notice to the Committee on Foreign Investment in the United States (CFIUS), and an application with the United States FERC. In addition, on June 15, 2017, a pre-merger Notification and Report Form on the WGL Acquisition was filed in accordance with the requirements of the HSR Act.

On May 10, 2017, common shareholders of WGL voted in favor of the Merger Agreement. On July 6, 2017, the FERC found that the transaction is consistent with the public interest and is now approved. Also as of July 17, 2017 when the waiting period required by Section 7A(b)(1) of the HSR Act expired, the merger was deemed approved by the Federal Trade Commission and the Department of Justice, such approval being valid for one year. On July 28, 2017, CFIUS provided its approval for the merger.

In addition, the staff to the State Corporation Commission (SCC) of Virginia has filed a productive report recommending approval of the proposed merger with conditions. That report and responses to the report are under consideration by the Virginia Commission, with a decision expected on or about October 20, 2017. In Maryland, the hearing before the Public Service Commission (PSC) of Maryland concluded on October 16, 2017 and a decision is expected on or about December 5, 2017. The hearing before the PSC of DC is scheduled to begin on or about December 5, 2017 with a decision expected to follow in the first half of 2018.

The WGL Acquisition is expected to close in the first half of 2018. AltaGas plans to fund the WGL Acquisition with the proceeds from its aggregate $2.6 billion bought deal and private placement of subscription receipts, which closed in the first quarter of 2017. In addition, AltaGas has US $3 billion available under its fully committed bridge facility, which can be drawn at the time of closing. As progress is made towards meeting closing conditions, AltaGas is moving forward with its long-term financing plan for the WGL Acquisition, the proceeds of which may be used to reduce the bridge facility, which itself will remain available for 12 to 18 months following the close of the WGL Acquisition. AltaGas continues to pursue the first phase of its asset sale process, which includes the Blythe and Tracy facilities in California and certain small non-core assets. Additional financing steps are expected to be undertaken in 2018, including additional asset sales, offerings of senior debt, hybrid securities and equity-linked securities (including preferred shares), subject to prevailing market conditions.

"WGL will provide significant growth and scale to all three of our business segments," said Mr. Harris. "We will look to execute on those opportunities while staying true to our strategy of a balanced portfolio of gas, power and utility assets and a low-risk value proposition for our shareholders."

Financial Update

Normalized EBITDA for the third quarter of 2017 was $190 million, compared to $176 million for the same quarter in 2016. The increase was mainly due to higher realized frac spread and frac exposed volumes, higher equity income from Petrogas, colder weather at certain Utilities, a full quarter of contributions from the Townsend Facility, contributions from the Pomona Energy Storage Facility, the absence of the true-up from the third quarter of 2016 related to the approval of Heritage Gas' customer retention program, and higher dispatch at the San Joaquin Facilities and Blythe. These increases were partially offset by the impact from the sale of the Ethylene Delivery Systems (EDS) and the Joffre Feedstock Pipeline (JFP) transmission assets in the first quarter of 2017, lower ethane revenue due to lower volumes and pricing, and the impact from the weaker U.S. dollar on reported results from U.S. assets. For the three months ended September 30, 2017, the average Canadian/U.S. dollar exchange rate decreased to 1.25 from an average of 1.31 in the same quarter of 2016, resulting in a decrease in normalized EBITDA of approximately $3 million.

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

Normalized funds from operations for the third quarter of 2017 were $143 million ($0.83 per share), compared to $137 million ($0.84 per share) for the same quarter in 2016, reflecting the same drivers as normalized EBITDA, partially offset by lower distributions from Petrogas. In the third quarter of 2017, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2016 - $3 million) 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.

For the third quarter of 2017, AltaGas recorded income tax expense of $14 million compared to $17 million in the same quarter of 2016. The decrease was mainly due to higher taxable earnings at PNG in the third quarter of 2016 as a result of the recovery of development costs for the PNG Pipeline Looping Project, partially offset by higher taxable earnings in the U.S. as a result of a portion of transaction costs incurred on the pending WGL Acquisition not being tax deductible.

On a U.S. GAAP basis, net income applicable to common shares for the third quarter of 2017 was $18 million ($0.10 per share), compared to $46 million ($0.28 per share) for the same quarter in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition, higher unrealized losses recognized on risk management contracts, higher depreciation and amortization expense, and higher preferred share dividends, partially offset by the same previously referenced factors resulting in the increase in normalized EBITDA.

Normalized net income was $48 million ($0.28 per share) for the third quarter of 2017, compared to $38 million ($0.23 per share) reported for the same quarter in 2016. The increase was mainly due to the same previously referenced factors resulting in the increase in normalized EBITDA, partially offset by higher depreciation and amortization expense, and higher preferred share dividends. Normalizing items in the third quarter of 2017 included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts, unrealized gains on long-term investments, and financing costs associated with the bridge facility for the pending WGL Acquisition. In the third quarter of 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, and recovery of development costs for the PNG Pipeline Looping Project.

Normalized EBITDA for the nine months ended September 30, 2017 was $584 million, compared to $507 million for the same period in 2016. The increase was mainly due to contributions from the Townsend Facility starting in the third quarter of 2016, higher realized frac spread and frac exposed volumes, higher earnings from Petrogas including the dividend income from the Petrogas Preferred Shares, colder weather experienced at certain of the Utilities, contributions from the Pomona Energy Storage Facility, higher revenue from NGL marketing, higher natural gas storage margins, the absence of equity losses from the Sundance B PPAs, customer and rate growth at the Utilities primarily due to the rate increase at ENSTAR, an early termination payment of $2 million from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract, and insurance proceeds received by SEMCO's non-regulated operations. These increases were partially offset by the impact of planned turnarounds at the Edmonton Ethane Extraction Plant (EEEP) and the Turin facility in the second quarter of 2017, lower ethane revenue, the impact of the sale of the EDS and JFP transmission assets, and the weaker U.S. dollar on reported results from U.S. assets. For the nine months ended September 30, 2017, the average Canadian/U.S. dollar exchange rate decreased to 1.31 from an average of 1.32 for the same period in 2016, resulting in a decrease in normalized EBITDA of approximately $4 million.

Normalized funds from operations for the nine months ended September 30, 2017 were $436 million ($2.57 per share), compared to $383 million ($2.48 per share) for the same period in 2016, reflecting the same drivers as normalized EBITDA, partially offset by lower cash distributions from Petrogas. During the nine months ended September 30, 2017, AltaGas received $9 million of dividend income from the Petrogas Preferred Shares (2016 - $3 million) and $4 million of common share dividends from Petrogas (2016 - $18 million). Petrogas retained cash to fund its growth capital program and for general corporate purposes.

AltaGas recorded income tax expense of $43 million for the nine months ended September 30, 2017 compared to $27 million in the same period of 2016. The increase was primarily due to the absence of the $10 million tax recovery related to the Tidewater Gas Asset Disposition recorded in the first quarter of 2016. In addition, a portion of transaction costs incurred on the pending

WGL Acquisition and unrealized losses on certain risk management contracts were not tax deductible, resulting in higher tax expense of approximately $7 million.

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 nine months ended September 30, 2017 was $41 million ($0.24 per share) compared to $118 million ($0.76 per share) for the same period in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition, higher unrealized losses on risk management contracts, the unrealized loss recognized upon ceasing to account for the Tidewater investment using the equity method, higher income tax, interest, depreciation and amortization expense, higher preferred share dividends, and higher losses on sale of assets, 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 nine months ended September 30, 2017 compared to the same period in 2016 as a result of the same factors impacting net income, as well as the increase in common shares outstanding in 2017.

Normalized net income was $141 million ($0.83 per share) for the nine months ended September 30, 2017, compared to $105 million ($0.68 per share) reported for the same period in 2016. The increase was driven by the same factors impacting normalized EBITDA, partially offset by higher income tax, interest, depreciation and amortization expense, and higher preferred share dividends. For the nine months ended September 30, 2017, normalizing items included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts and long-term investments, losses on sale of assets, provision on assets, and financing costs associated with the bridge facility for the pending WGL Acquisition. For the nine months ended September 30, 2016, normalizing items included after-tax amounts related to transaction costs incurred on acquisitions, unrealized gains on risk management contracts and long-term investments, gains on sale of assets, dilution loss recognized on investment accounted for by the equity method, provision on investment accounted for by the equity method, recovery of development costs for the PNG Pipeline Looping Project, and restructuring costs.

2017 OUTLOOK

AltaGas continues to expect to deliver low double digit percentage normalized EBITDA growth in 2017 compared to 2016. All three business segments are expected to drive the annual growth in 2017 compared to 2016, with the Gas segment expecting to generate the highest normalized EBITDA percentage growth, 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 and partial year contributions from Townsend 2A entering commercial operations in October 2017;
- Higher earnings from frac exposed volumes as a result of higher commodity prices;
- Higher expected earnings from the Northwest Hydro Facilities due to contractual price increases and continued improvements in operational efficiency resulting in higher volumes and lower operating costs;
- Higher earnings from Petrogas due to a full year of income from the Petrogas preferred shares and increased contributions from all of Petrogas' business segments;
- Actual weather during the nine months ended September 30, 2017 was colder at certain of the Utilities compared to the warmer weather experienced in 2016, with normal weather expected for the remainder of 2017;
- Contributions from the Pomona Energy Storage Facility, which entered commercial operation on December 31, 2016;
- Higher earnings from renewables primarily due to stronger wind generation at the Bear Mountain wind facility and fewer planned outages at the Craven biomass facility;
- Higher earnings from energy services primarily due to higher revenue from NGL marketing and higher natural gas storage margins;

- Higher expected volumes at the Gordondale facility following the modifications made to the take-or-pay agreement on June 29, 2017 for volumes solely above the existing take-or-pay commitment to incent Birchcliff Energy Inc. (Birchcliff) to deliver additional volumes; and
- Decrease in administrative expenses as a result of various cost savings initiatives.

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, scheduled turnarounds at EEEP and the Turin facility, which occurred in the second quarter of 2017, lower ethane revenue, and lower average realized rates at the Blair Creek Facility. A turnaround at the Gordondale facility was completed in the third quarter of 2017 that had no material impact on normalized EBITDA, as the majority of Gordondale's turnaround costs were capitalized and revenues billed under a take-or-pay arrangement.

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

In the Gas segment, additional earnings in 2017 are expected to be driven by a full year of contributions from the Townsend Facility and a partial year of contributions from Townsend 2A entering commercial operations in October 2017, higher frac exposed volumes and commodity prices, higher earnings from Petrogas due to a full year of income from the Petrogas Preferred Share dividends and increased contributions from all of Petrogas' business segments, higher NGL marketing revenue and natural gas storage margins, and higher volumes expected at the Gordondale facility due to the modifications made to the take-or-pay agreement with Birchcliff. The additional earnings are partially offset by the closing of the sale of the EDS and JFP transmission pipelines in the first quarter of 2017, lower ethane revenue at EEEP and the Pembina Empress Extraction Plant (PEEP), scheduled turnarounds at EEEP and the Turin facility in the second quarter of 2017, and lower average realized rates at the Blair Creek Facility. Based on current commodity prices, AltaGas estimates an average of approximately 9,400 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 6,500 Bbls/d at an average price of approximately $24/Bbl excluding basis differentials.

In the Power segment, increased earnings are expected to be driven by higher expected earnings from the Northwest Hydro Facilities due to contractual price increases and continued improvements in productivity resulting in higher volumes generated and lower operating costs, contributions from a full year of operations at the Pomona Energy Storage Facility, fewer planned outages expected at the Craven biomass facility, and higher earnings from the Bear Mountain wind facility due to stronger wind generation. The earnings and cash flows from the Northwest Hydro Facilities 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.

The Utilities segment is expected to report increased earnings in 2017 mainly driven by the colder weather during the nine months ended September 30, 2017 at certain of the Utilities and assuming normal weather for the remainder of 2017, compared to the warmer weather experienced at all of the Utilities in 2016. In addition, higher customer usage at certain of the Utilities and lower expenses are expected to benefit earnings. These increases are expected to be 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. ENSTAR expects EBITDA to increase by approximately US$6 million for the full year of 2017 (US$4 million through end of September 2017) as a result of the rate increase in 2016, which was made permanent by the rate case decision approved by the RCA on September 22, 2017 and a further permanent rate increase anticipated to be implemented by December 2017.

Earnings generated from AltaGas' U.S. assets are exposed to fluctuations in the U.S./Canadian dollar exchange rate. In general, the strengthening of the U.S. dollar compared to the Canadian dollar will have a positive impact on earnings. The weakening of the U.S. dollar will have the opposite effect. To the extent AltaGas has outstanding U.S. dollar denominated debt and/or preferred shares, fluctuations in the U.S./Canadian dollar exchange rate will have the opposite effect as compared to the impact on earnings generated from AltaGas' U.S. assets.

Monthly Common Share Dividend and Quarterly Preferred Share Dividends

- The Board of Directors approved a dividend of $0.1825 per common share. The dividend will be paid on December 15, 2017, to common shareholders of record on November 27, 2017. The ex-dividend date is November 24, 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 September 30, 2017 and ending December 30, 2017, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017;
- The Board of Directors approved a dividend of $0.21425 per share for the period commencing September 30, 2017 and ending December 30, 2017, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017;
- The Board of Directors approved a dividend of US$0.330625 per share for the period commencing September 30, 2017 and ending December 30, 2017, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing September 30, 2017, and ending December 30, 2017, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017;
- The Board of Directors approved a dividend of $0.296875 per share for the period commencing September 30, 2017, and ending December 30, 2017, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017;
- The Board of Directors approved a dividend of $0.328125 per share for the period commencing September 30, 2017, and ending December 30, 2017, on AltaGas' outstanding Series I Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017; and
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing September 30, 2017, and ending December 30, 2017, on AltaGas' outstanding Series K Preferred Shares. The dividend will be paid on December 29, 2017 to shareholders of record on December 13, 2017. The ex-dividend date is December 12, 2017.

Consolidated Financial Review

($ millions)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Revenue	**502**	492	**1,811**	1,528
Normalized EBITDA[(1)]	**190**	176	**584**	507
Net income applicable to common shares	**18**	46	**41**	118
Normalized net income[(1)]	**48**	38	**141**	105
Total assets	**9,932**	9,952	**9,932**	9,952
Total long-term liabilities	**4,624**	4,541	**4,624**	4,541
Net additions to property, plant and equipment	**147**	80	**274**	284
Dividends declared[(2)]	**90**	85	**268**	233
Normalized funds from operations[(1)]	**143**	137	**436**	383

($ per share, except shares outstanding)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Net income per common share - basic	**0.10**	0.28	**0.24**	0.76
Net income per common share - diluted	**0.10**	0.28	**0.24**	0.76
Normalized net income - basic[(1)]	**0.28**	0.23	**0.83**	0.68
Dividends declared[(2)]	**0.53**	0.52	**1.58**	1.51
Normalized funds from operations[(1)]	**0.83**	0.84	**2.57**	2.48
Shares outstanding - basic (millions)				
During the period[(3)]	**172**	164	**170**	154
End of period	**173**	165	**173**	165

(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 third quarter results, progress on construction projects, the pending WGL Acquisition 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 89018625. 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 89018625. The replay will expire at 2:00 p.m. (Eastern) on October 21, 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 and nine months ended September 30, 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

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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", "continue", "look forward", "future", "pursue", "grow" "believe", "achieve", "aim", "remain", "advance", "seek", "propose", "position", "estimate", "forecast", "expect", "project", "launch". "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; AltaGas' vision and strategy; 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; strategic position of assets, ability to provide long-term sustainable value; 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, expectations with respect to the WGL Acquisition including the expected closing date, hearing dates and decision dates, ability to obtain, and timeline for obtaining, regulatory and other approvals and meeting closing conditions, anticipated benefits of the WGL Acquisition including the alignment with AltaGas' vision and strategy, portfolio and scale of assets of the combined entity, nature, number, value and quality of the assets, the nature, number, value, quality, timing and stage of development of growth projects and opportunities, EPS accretion and normalized FFOPS accretion, both in the first full year following the WGL Acquisition and over the period to 2021, growth on an absolute dollar and per share basis, strength of earnings (including, without limitation, EPS, FFOPS and EBITDA growth rate *through 2021), annual dividend growth rate, dividend payout ratios, ability of the WGL Acquisition to support dividend growth, compatibility, strength and focus of the combined entity, complimentary nature of businesses, ability to increase scale and provide diversity and AltaGas' ability to move forward with long-term financing plans, ability to sell Blythe and Tracy and other non-core assets and complete long-term financing plan in phases; ability to complete and timeline for completing additional financing steps including offerings, intended use of proceeds from financing plans, expected use of proceeds from the issuance of subscription receipts; expectations regarding availability of and indebtedness under bridge facility and expectations regarding reduction and maturity of bridge facility, AltaGas' ability to execute on opportunities and maintain a balanced portfolio among business segments; expectations regarding current projects under construction and new opportunities for 2017 driving shareholder value; expectations with respect to the Townsend Facility and Townsend 2A including, contribution to earnings and impact on earnings; gas volumes and ramping of gas volumes, timing of effectiveness of take or pay arrangements; expectations relating to the North Pine Facility including timeline for construction completion and commercial operation, facility specification, expectations regarding sources to fill capacity; expectations with respect to RIPET including cost, timing of construction completion, delivery of modules and commercial operations; AltaGas' ability to source additional processing and gathering capacity and nature of discussions with producers; expectations regarding the Gordondale facility including gas volumes, the ability to fill capacity and expand; expectations relating to the Marquette Connector Pipeline including timeline for engineering and property acquisition, construction and in-service date; cost, location, ability to construct, connection capability to existing pipelines, gas supply opportunities and potential benefits; expectations regarding the utilities segment including opportunities for system betterment and customer growth and expectations relating to ENSTAR's 2016 rate case; expectations relating to AltaGas' ability to fund its projects and business; expectations regarding energy storage and solar opportunities, ability to enhance the value of AltaGas' California power position, expectations regarding the suitability and locational benefits of AltaGas' greenfield and brownfield sites throughout California and ability to attract power purchase agreements, bid in RFPs or negotiate bilateral agreements; expectations regarding Sonoran including potential for re-configuring, offering resource adequacy, energy and ancillary services, using multiple transmission options, serving several western U.S. states, nature of bilateral discussions, potential counterparties and ability to enter into multi-year agreements; expectations relating to the Northwest Hydro Facilities including expected generation, operational efficiency, operating costs, contributions to earnings and seasonality impacts (including water flow patterns); expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including dividends from Petrogas, and Petrogas' retention of cash and contributions; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains, frac spread exposure, frac exposed volumes, NGL marketing revenue, storage margins, recovery in commodity prices, weather, wind generation 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; expectations regarding rates at the Blair Creek facility; 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 dividends (including 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 period ended September 30, 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 period ended September 30, 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

This Management's Discussion and Analysis (MD&A) dated October 18, 2017 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 and nine months ended September 30, 2017. This MD&A 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 and nine months ended September 30, 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 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", "launch", "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", "2017 Outlook", "Developments Relating to the Pending WGL Acquisition", "Growth Capital", and "Future Changes in Accounting Principles" and under those headings specifically include AltaGas' expectations of growing demand for clean energy and key fuel sources; 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, hearing dates and decision dates, ability to obtain, and timeline for obtaining, regulatory and other approvals and meeting closing conditions, the aggregate cash consideration including the anticipated sources of financing thereof, ability to move forward with long-term financing plans, ability to sell Blythe and Tracy and other non-core assets and complete long-term financing plan in phases, ability to complete and timeline for completing additional financing steps including offerings, intended use of proceeds from financing plans, 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 and indebtedness under bridge facility and expectations regarding reduction 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 phased development or development in trains, timing of effectiveness of take-or-pay arrangements and expected gas volumes from Painted Pony and timing of ramping with respect to Townsend 2A, plans for transport including new NGL pipelines and contribution to earnings; expectations with respect to RIPET including cost, 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, offtake opportunities, expectations of *serving growing demand in Asia and offering new markets to producers and timing of construction completion, delivery of modules 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, RIPET and Alaska highway truck terminal, facility specifications, location, handling capability, service area, cost, product mix, timeline for construction, commercial operation and second train, expectations regarding sources to fill capacity; AltaGas' expectations with respect to BRFN's trial and impact of trial on construction of second train of Townsend Phase 2, the North Pine Facility and North Pine Pipelines; 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 relating to the Marquette Connector Pipeline including timeline for, engineering and property acquisitions, 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 regarding demand for sites with solar and wind characteristics, expectations regarding the suitability and locational benefits of AltaGas' greenfield and brownfield sites throughout California and ability to attract power purchase agreements, bid in RFPs or negotiate bilateral agreements; expectations relating to the AltaGas Pomona Energy Storage Project, potential expansion opportunities, impact successful commercial operations has on AltaGas, on earnings and potential future development opportunities; expectations regarding storage needs in Los Angeles Basin; expectations of AltaGas' suitability for developing future energy storage; expectations relating to the Northwest Hydro Facilities including expected generation, operating expenses, contributions to earnings and seasonality impacts (including water flow patterns); expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including dividends from Petrogas, and Petrogas' retention of cash and contributions; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains, frac spread exposure, frac exposed volumes, NGL marketing revenue, storage margins, recovery in commodity prices, weather, wind generation 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; expectations regarding volumes at the Gordondale facility and expansion of the gas gathering system and facility; expectations regarding rates at the Blair Creek facility, expected earnings from the Utilities segment including from rate base and customer growth, from ENSTAR in connection with its 2016 rate case, higher customer usage, lower interruptible storage service revenue from CINGSA, AltaGas' ability to focus on enhancing productivity and streamlining businesses; expectations regarding dividends (including the payment of dividends) 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. The Corporation's long-term strategy is to grow in attractive areas and maintain a long-term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. AltaGas' business strategy is underpinned by the growing demand for clean energy with natural gas as a key fuel source. 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, natural gas and NGL marketing, and the Corporation's indirectly held one-third interest in Petrogas Energy Corp. (Petrogas), through which AltaGas' 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, which deliver clean and affordable natural gas to approximately 575,000 customers through ownership of five regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States.

THIRD QUARTER FINANCIAL HIGHLIGHTS

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

- Normalized EBITDA was $190 million, an increase of 8 percent compared to $176 million in the third quarter of 2016;
- Normalized funds from operations were $143 million ($0.83 per share), an increase of 4 percent compared to $137 million ($0.84 per share) in the third quarter of 2016;
- Net income applicable to common shares was $18 million ($0.10 per share) compared to $46 million ($0.28 per share) in the third quarter of 2016;
- Normalized net income was $48 million ($0.28 per share), an increase of 26 percent compared to $38 million ($0.23 per share) in the third quarter of 2016;
- Net debt was $3.6 billion as at September 30, 2017, compared to $3.9 billion as at December 31, 2016;
- Debt-to-total capitalization ratio was 44 percent as at September 30, 2017, compared to 46 percent as at December 31, 2016;
- In August 2017, the Michigan Public Service Commission (MPSC) approved SEMCO's application to construct, own, and operate the Marquette Connector Pipeline (MCP); and
- In September 2017, the Regulatory Commission of Alaska (RCA) issued a decision on ENSTAR's 2015 test-year rate case. As a result, the rate increase implemented in the third quarter of 2016 was made permanent and a further permanent rate increase is anticipated to be implemented by December 2017.

HIGHLIGHTS SUBSEQUENT TO QUARTER END

- On October 1, 2017, commercial operations commenced at Townsend 2A, a 99 Mmcf/d shallow-cut gas processing facility located on the existing Townsend site, adjacent to the currently operating Townsend Facility;
- On October 4, 2017, AltaGas issued an aggregate of $450 million senior unsecured medium-term notes (MTNs) consisting of $200 million of MTNs with a coupon rate of 3.98 percent maturing on October 4, 2027, and $250 million of MTNs with a coupon rate of 4.99 percent maturing on October 4, 2047; and
- On October 18, 2017, the Board of Directors approved an increase in the monthly dividend by $0.0075 per common share to $0.1825 ($2.19 per common share annualized) effective for the November dividend, payable on December 15, 2017, a 4.3 percent increase.

CONSOLIDATED FINANCIAL REVIEW

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2017**	2016	**2017**	2016
Revenue	**502**	492	**1,811**	1,528
Normalized EBITDA[(1)]	**190**	176	**584**	507
Net income applicable to common shares	**18**	46	**41**	118
Normalized net income[(1)]	**48**	38	**141**	105
Total assets	**9,932**	9,952	**9,932**	9,952
Total long-term liabilities	**4,624**	4,541	**4,624**	4,541
Net additions to property, plant and equipment	**147**	80	**274**	284
Dividends declared[(2)]	**90**	85	**268**	233
Normalized funds from operations[(1)]	**143**	137	**436**	383

	Three Months Ended September 30		Nine Months Ended September 30	
($ per share, except shares outstanding)	**2017**	2016	**2017**	2016
Net income per common share - basic	**0.10**	0.28	**0.24**	0.76
Net income per common share - diluted	**0.10**	0.28	**0.24**	0.76
Normalized net income - basic[(1)]	**0.28**	0.23	**0.83**	0.68
Dividends declared[(2)]	**0.53**	0.52	**1.58**	1.51
Normalized funds from operations[(1)]	**0.83**	0.84	**2.57**	2.48
Shares outstanding - basic (millions)				
During the period[(3)]	**172**	164	**170**	154
End of period	**173**	165	**173**	165

(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 September 30

Normalized EBITDA for the third quarter of 2017 was $190 million, compared to $176 million for the same quarter in 2016. The increase was mainly due to higher realized frac spread and frac exposed volumes, higher equity income from Petrogas, colder weather at certain Utilities, a full quarter of contributions from the Townsend Facility, contributions from the Pomona Energy Storage Facility, the absence of the true-up from the third quarter of 2016 related to the approval of Heritage Gas' customer retention program, and higher dispatch at the San Joaquin Facilities and Blythe. These increases were partially offset by the impact from the sale of the Ethylene Delivery Systems (EDS) and the Joffre Feedstock Pipeline (JFP) transmission assets in the first quarter of 2017, lower ethane revenue due to lower volumes and pricing, and the impact from the weaker U.S. dollar on reported results from U.S. assets. For the three months ended September 30, 2017, the average Canadian/U.S. dollar exchange rate decreased to 1.25 from an average of 1.31 in the same quarter of 2016, resulting in a decrease in normalized EBITDA of approximately $3 million.

Normalized funds from operations for the third quarter of 2017 were $143 million ($0.83 per share), compared to $137 million ($0.84 per share) for the same quarter in 2016, reflecting the same drivers as normalized EBITDA, partially offset by lower distributions from Petrogas. In the third quarter of 2017, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2016 - $3 million) 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 third quarter of 2017 were $126 million, compared to $114 million for the same quarter in 2016. The increase was mainly due to transaction costs incurred on the pending WGL Acquisition of approximately $9 million and new assets placed into service. Depreciation and amortization expense for the third quarter of 2017 was $69 million, compared to $67 million for the same quarter in 2016. The increase was mainly due to new assets placed into service. Interest expense for the third quarter of 2017 was $40 million, compared to $39 million for the same quarter in 2016. The increase was mainly due to financing costs of approximately $4 million (pre-tax) associated with the bridge facility for the pending WGL Acquisition, higher average interest rates, partially offset by lower average debt outstanding and higher capitalized interest. 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 $14 million for the third quarter of 2017 compared to $17 million in the same quarter of 2016. The decrease was mainly due to higher taxable earnings at PNG in the third quarter of 2016 as a result of the recovery of development costs for the PNG Pipeline Looping Project, partially offset by higher taxable earnings in the U.S. as a result of a portion of transaction costs incurred on the pending WGL Acquisition not being tax deductible.

Net income applicable to common shares for the third quarter of 2017 was $18 million ($0.10 per share), compared to $46 million ($0.28 per share) for the same quarter in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition, higher unrealized losses recognized on risk management contracts, higher depreciation and amortization expense, and higher preferred share dividends, partially offset by the same previously referenced factors resulting in the increase in normalized EBITDA.

Normalized net income was $48 million ($0.28 per share) for the third quarter of 2017, compared to $38 million ($0.23 per share) reported for the same quarter in 2016. The increase was mainly due to the same previously referenced factors resulting in the increase in normalized EBITDA, partially offset by higher depreciation and amortization expense, and higher preferred share dividends. Normalizing items in the third quarter of 2017 included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts, unrealized gains on long-term investments, and financing costs associated with the bridge facility for the pending WGL Acquisition. In the third quarter of 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, and recovery of development costs for the PNG Pipeline Looping Project.

Nine Months Ended September 30

Normalized EBITDA for the nine months ended September 30, 2017 was $584 million, compared to $507 million for the same period in 2016. The increase was mainly due to contributions from the Townsend Facility starting in the third quarter of 2016, higher realized frac spread and frac exposed volumes, higher earnings from Petrogas including the dividend income from the Petrogas Preferred Shares, colder weather experienced at certain of the Utilities, contributions from the Pomona Energy Storage Facility, higher revenue from NGL marketing, higher natural gas storage margins, the absence of equity losses from the Sundance B PPAs, customer and rate growth at the Utilities primarily due to the rate increase at ENSTAR, an early termination payment of $2 million from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract, and insurance proceeds received by SEMCO's non-regulated operations. These increases were partially offset by the impact of planned turnarounds at the Edmonton Ethane Extraction Plant (EEEP) and the Turin facility in the second quarter of 2017, lower ethane revenue, the impact of the sale of the EDS and JFP transmission assets, and the weaker U.S. dollar on reported results from U.S. assets. For the nine months ended September 30, 2017, the average Canadian/U.S. dollar exchange rate decreased to 1.31 from an average of 1.32 for the same period in 2016, resulting in a decrease in normalized EBITDA of approximately $4 million.

Normalized funds from operations for the nine months ended September 30, 2017 were $436 million ($2.57 per share), compared to $383 million ($2.48 per share) for the same period in 2016, reflecting the same drivers as normalized EBITDA, partially offset by lower cash distributions from Petrogas. During the nine months ended September 30, 2017, AltaGas received $9 million of dividend income from the Petrogas Preferred Shares (2016 - $3 million) and $4 million of common share dividends from Petrogas (2016 - $18 million). Petrogas retained cash to fund its growth capital program and for general corporate purposes.

Operating and administrative expenses for the nine months ended September 30, 2017 were $422 million, compared to $378 million for the same period in 2016. The increase was mainly due to transaction costs incurred on the pending WGL Acquisition of approximately $50 million, costs incurred on the turnarounds at EEEP and the Turin facility of approximately $4 million, and new assets placed into service, partially offset by the absence of the non-utility workforce restructuring costs of approximately $7 million incurred in the second quarter of 2016. Depreciation and amortization expense for the nine months ended September 30, 2017 was $211 million, compared to $202 million for the same period in 2016. The increase was mainly due to new assets placed into service. Interest expense for the nine months ended September 30, 2017 was $127 million, compared to $111 million for the same period in 2016. The increase was mainly due to financing costs of approximately $15 million (pre-tax) associated with the bridge facility for the pending WGL Acquisition, higher average interest rates, and lower capitalized interest, 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 $43 million for the nine months ended September 30, 2017 compared to $27 million in the same period of 2016. The increase was primarily due to the absence of the $10 million tax recovery related to the Tidewater Gas Asset Disposition recorded in the first quarter of 2016. In addition, a portion of transaction costs incurred on the pending WGL Acquisition and unrealized losses on certain risk management contracts were not tax deductible, resulting in higher tax expense of approximately $7 million.

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.

At the end of May 2017, AltaGas concluded that it no longer exercised significant influence over Tidewater Midstream and Infrastructure Ltd. (Tidewater). Consequently, AltaGas ceased accounting for the investment under the equity method and now accounts for the Tidewater common shares at fair value. As a result, AltaGas recorded an unrealized pre-tax loss of approximately $8 million in the second quarter of 2017. Subsequent changes in fair value are recognized in the Consolidated Statement of Income. For the nine months ended September 30, 2017, AltaGas recorded an unrealized pre-tax loss of approximately $3 million representing the change in fair value of the investment in Tidewater.

In the second quarter of 2017, the Power segment disposed of certain non-core development stage wind assets in Alberta for proceeds of approximately $1 million, resulting in a pre-tax gain on disposition of approximately $1 million. This was largely offset by a pre-tax provision of $1 million taken on certain non-core development stage gas-fired peaking assets in Alberta in the same quarter.

Net income applicable to common shares for the nine months ended September 30, 2017 was $41 million ($0.24 per share) compared to $118 million ($0.76 per share) for the same period in 2016. The decrease was mainly due to the transaction costs incurred on the pending WGL Acquisition, higher unrealized losses on risk management contracts, the unrealized loss recognized upon ceasing to account for the Tidewater investment using the equity method, higher income tax, interest, depreciation and amortization expense, higher preferred share dividends, and higher losses on sale of assets, 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 nine months ended September 30, 2017 compared to the same period in 2016 as a result of the same factors impacting net income, as well as the increase in common shares outstanding in 2017.

Normalized net income was $141 million ($0.83 per share) for the nine months ended September 30, 2017, compared to $105 million ($0.68 per share) reported for the same period in 2016. The increase was driven by the same factors impacting normalized EBITDA, partially offset by higher income tax, interest, depreciation and amortization expense, and higher preferred share dividends. For the nine months ended September 30, 2017, normalizing items included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts and long-term investments, losses on sale of assets, provision on assets, and financing costs associated with the bridge facility for the pending WGL Acquisition. For the nine months ended September 30, 2016, normalizing items included after-tax amounts related to transaction costs incurred on acquisitions, unrealized gains on risk management contracts and long-term investments, gains on sale of assets, dilution loss recognized on investment accounted for by the equity method, provision on investment accounted for by the equity method, recovery of development costs for the PNG Pipeline Looping Project, and restructuring costs.

2017 OUTLOOK

AltaGas continues to expect to deliver low double digit percentage normalized EBITDA growth in 2017 compared to 2016. All three business segments are expected to drive the annual growth in 2017 compared to 2016, with the Gas segment expecting to generate the highest normalized EBITDA percentage growth, 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 and partial year contributions from the first train of Townsend Phase 2 (Townsend 2A) entering commercial operations in October 2017;
- Higher earnings from frac exposed volumes as a result of higher commodity prices;
- Higher expected earnings from the Northwest Hydro Facilities due to contractual price increases and continued improvements in operational efficiency resulting in higher volumes and lower operating costs;
- Higher earnings from Petrogas due to a full year of income from the Petrogas preferred shares and increased contributions from all of Petrogas' business segments;
- Actual weather during the nine months ended September 30, 2017 was colder at certain of the Utilities compared to the warmer weather experienced in 2016, with normal weather expected for the remainder of 2017;
- Contributions from the Pomona Energy Storage Facility, which entered commercial operation on December 31, 2016;
- Higher earnings from renewables primarily due to stronger wind generation at the Bear Mountain wind facility and fewer planned outages at the Craven biomass facility;
- Higher earnings from energy services primarily due to higher revenue from NGL marketing and higher natural gas storage margins;
- Higher expected volumes at the Gordondale facility following the modifications made to the take-or-pay agreement on June 29, 2017 for volumes solely above the existing take-or-pay commitment to incent Birchcliff Energy Inc. (Birchcliff) to deliver additional volumes; and
- Decrease in administrative expenses as a result of various cost savings initiatives.

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, scheduled turnarounds at EEEP and the Turin facility, which occurred in the second quarter of 2017, lower ethane revenue, and lower average realized rates at the Blair Creek facility. A turnaround at the Gordondale facility was completed in the third quarter of 2017 that had no material impact on normalized EBITDA, as the majority of Gordondale's turnaround costs were capitalized and revenues billed under a take-or-pay arrangement.

Normalized funds from operations are expected to grow by a high single digit percentage, driven by the same factors noted above for normalized EBITDA growth, but partially offset by higher current tax expenses and lower common share dividends from Petrogas, as Petrogas is retaining 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. Consistent with prior guidance, AltaGas continues to pursue the first phase of its asset sale process, which includes Blythe and the Tracy facility in California and certain smaller non-core assets (see *Developments Relating to the Pending WGL Acquisition* section of this MD&A for further information).

In the Gas segment, additional earnings in 2017 are expected to be driven by a full year of contributions from the Townsend Facility and a partial year of contributions from Townsend 2A entering commercial operations in October 2017, higher frac exposed volumes and commodity prices, higher earnings from Petrogas due to a full year of income from the Petrogas Preferred Share dividends and increased contributions from all of Petrogas' business segments, higher NGL marketing revenue and natural gas storage margins, and higher volumes expected at the Gordondale facility due to the modifications made to the take-or-pay agreement with Birchcliff. The additional earnings are partially offset by the closing of the sale of the EDS and JFP transmission pipelines in the first quarter of 2017, lower ethane revenue at EEEP and the Pembina Empress Extraction Plant (PEEP), scheduled turnarounds at EEEP and the Turin facility in the second quarter of 2017, and lower average realized rates at the Blair Creek facility. Based on current commodity prices, AltaGas estimates an average of approximately 9,400 Bbls/d will be exposed to frac spreads prior to hedging activities in 2017. For the remainder of 2017, AltaGas has frac hedges in place for approximately 6,500 Bbls/d at an average price of approximately $24/Bbl excluding basis differentials.

In the Power segment, increased earnings are expected to be driven by higher expected earnings from the Northwest Hydro Facilities due to contractual price increases and continued improvements in productivity resulting in higher volumes generated and lower operating costs, contributions from a full year of operations at the Pomona Energy Storage Facility, fewer planned outages expected at the Craven biomass facility, and higher earnings from the Bear Mountain wind facility due to stronger wind generation. The earnings and cash flows from the Northwest Hydro Facilities 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.

The Utilities segment is expected to report increased earnings in 2017 mainly driven by the colder weather during the nine months ended September 30, 2017 at certain of the Utilities and assuming normal weather for the remainder of 2017, compared to the warmer weather experienced at all of the Utilities in 2016. In addition, higher customer usage at certain of the Utilities and lower expenses are expected to benefit earnings. These increases are expected to be 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. ENSTAR expects EBITDA to increase by approximately US$6 million for the full year of 2017 (US$4 million through end of September 2017) as a result of the rate increase in 2016, which was made permanent by the rate case decision approved by the RCA on September 22, 2017, and a further permanent rate increase anticipated to be implemented by December 2017.

Earnings generated from AltaGas' U.S. assets are exposed to fluctuations in the U.S./Canadian dollar exchange rate. In general, the strengthening of the U.S. dollar compared to the Canadian dollar will have a positive impact on earnings. The weakening of the U.S. dollar will have the opposite effect. To the extent AltaGas has outstanding U.S. dollar denominated debt and/or preferred shares, fluctuations in the U.S./Canadian dollar exchange rate will have the opposite effect as compared to the impact on earnings generated from AltaGas' U.S. assets.

DEVELOPMENTS RELATING TO THE PENDING WGL ACQUISITION

Pending Acquisition of WGL Holdings, Inc. (WGL)

On January 25, 2017, the Corporation entered into a merger 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$6.7 billion, including the assumption of approximately US$2.2 billion of debt as at June 30, 2017.

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 236,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas expects that it will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

Consummation of the WGL Acquisition is subject to certain closing conditions, including 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 (HSR Act).

Regulatory applications were filed with the PSC of DC, the PSC of MD, and the SCC of VA on April 24, 2017. On the same date, AltaGas and WGL also filed their voluntary Joint Notice to the CFIUS, and an application with FERC. In addition, the staff to the SCC of VA has filed a productive report recommending approval of the proposed merger with conditions. That report and responses to the report are under consideration by the Virginia Commission, with a decision expected on or about October 20, 2017. In Maryland, the hearing before the PSC of MD concluded on October 16, 2017 and a decision is expected on or about December 5, 2017. The hearing before the PSC of DC is scheduled to begin on or about December 5, 2017 with a decision expected to follow in the first half of 2018. On May 10, 2017, WGL common shareholders voted in favor of the Merger Agreement governing the proposed WGL Acquisition. On July 6, 2017, the FERC found that the transaction is consistent with the public interest and is now approved. Also as of July 17, 2017 when the waiting period required by Section 7A(b)(1) of the HSR Act expired, the merger was deemed approved by the Federal Trade Commission and the Department of Justice, such approval being valid for one year. On July 28, 2017, CFIUS provided its approval for the merger.

The WGL Acquisition is expected to close in the first half of 2018. AltaGas plans to fund the WGL Acquisition with the proceeds from its aggregate $2.6 billion bought deal and private placement of subscription receipts, which closed in the first quarter of 2017 *(see Subscription Receipts section below)*. In addition, AltaGas has US$3 billion available under its fully committed bridge facility, which can be drawn at the time of closing. As progress is made towards meeting closing conditions, AltaGas is moving forward with its long-term financing plan for the WGL Acquisition, the proceeds of which may be used to reduce the bridge facility, which itself will remain available for 12 to 18 months following the close of the WGL Acquisition. AltaGas continues to pursue the first phase of its asset sale process, which includes Blythe and the Tracy facility in California and certain small non-core assets. Additional financing steps are expected to be undertaken in 2018, including additional asset sales, offerings of senior debt, hybrid securities, and equity-linked securities (including preferred shares), subject to prevailing market conditions.

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 WGL Acquisition 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 now expects net capital expenditures in the range of $500 to $550 million for 2017. AltaGas' Gas segment will account for approximately 65 to 70 percent of total capital expenditures, while AltaGas' Utility segment will account for approximately 25 to 30 percent and the Power segment will account for approximately 5 to 10 percent. Gas and Power maintenance capital is expected to be approximately $20 to $30 million of total capital expenditures in 2017. The majority of AltaGas' capital expenditures relating to its Gas segment have been or will be allocated towards AltaGas' growth projects including Ridley Island Propane Export Terminal (RIPET), Townsend 2A, the first train of 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 $1.6 billion available under its credit facilities and cash and cash equivalents of $25 million as at September 30, 2017, combined with access to capital markets.

Townsend Gas Processing Facility Expansion (Townsend Phase 2)

On October 1, 2017, commercial operations commenced at Townsend 2A. Construction was completed slightly ahead of schedule and approximately $5 million under budget with a final cost (including the addition of incremental field compression equipment to move raw gas production from the Blair Creek area to Townsend) of approximately $125 million. AltaGas and Painted Pony Energy Ltd. (Painted Pony) have entered into 20-year take-or-pay agreements in respect of Townsend 2A and the incremental field compression equipment, with the take-or-pay expected to take full effect on January 1, 2018. Volumes are expected to progressively ramp up through the fourth quarter of 2017 to the first quarter of 2018. NGL produced from Townsend 2A will be transported to AltaGas' North Pine Facility via existing and planned pipelines owned by AltaGas.

North Pine NGL Project

On October 19, 2016, AltaGas reached a positive Final Investment Decision (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 RIPET. The North Pine Facility will have 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 are being 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. Facility and pipeline construction activities commenced in June 2017. Construction is progressing ahead of schedule, moving the target commercial on-stream date up from the first quarter of 2018 to early December 2017.

The capital cost of the first train and associated pipelines is estimated to come in under budget at approximately $100 to $110 million. AltaGas has entered into long-term supply agreements with Painted Pony for a portion of the total capacity, which includes dedication of all of Painted Pony's NGL produced at the Townsend and Blair Creek facilities. The remaining capacity is expected to be filled with NGL produced in the area.

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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 BRFN's primary action alleging breaches by the Province of British Columbia of BRFN's treaty rights. On May 31, 2017, the application for the interlocutory injunction was dismissed by the Supreme Court of British Columbia. The trial for the underlying action against the Province of British Columbia is expected to commence in March 2018. The BRFN action seeks, among other things: (1) a court declaration that, by causing or permitting cumulative impacts of various industrial developments, the Province has breached its treaty and fiduciary obligations to BRFN and has infringed BRFN's treaty rights; and (2) injunctive relief against any activities that would cause further cumulative effects. AltaGas does not expect related delays in the construction of the second train of Townsend Phase 2 (Townsend 2B), both trains of the North Pine Facility, and the North Pine Pipelines as such projects have received approval to construct from the British Columbia Oil and Gas Commission.

Ridley Island Propane Export Terminal

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

RIPET is expected to be the first propane export facility off the west coast of Canada. The site is near Prince Rupert, British Columbia, and is subleased from Ridley Terminals Inc. (RTI), which has a headlease with 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 50-60 rail cars a day through the existing CN rail network. The construction cost of RIPET is estimated to be approximately $450 to $500 million and RIPET is expected to ship 1.2 million tonnes of propane per annum (which is equivalent to approximately 40,000 Bbls/d of export capacity).

On May 5, 2017, AltaGas LPG Limited Partnership (AltaGas LPG), a wholly-owned subsidiary of AltaGas and Vopak Development Canada Inc. (Vopak), a wholly-owned subsidiary of Koninklijke Vopak N.V. (Royal Vopak), a public company incorporated under the laws of the Netherlands, formed Ridley Island LPG Export Limited Partnership (RILE LP) to develop, own, and operate RIPET. AltaGas' subsidiaries hold a 70 percent interest while Vopak holds a 30 percent interest in RILE LP. The construction cost of RIPET will be funded by AltaGas LPG and Vopak in proportion to their respective interests in RILE LP. As part of the arrangements, AltaGas entered into a long-term agreement for the capacity of RIPET with RILE LP, and AltaGas and certain of its subsidiaries will provide construction and operating services to RILE LP. RILE LP will be consolidated by AltaGas.

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 expected capacity of 1.2 million tonnes per annum. The remaining 50 percent is expected to be supplied by producers and other suppliers. AltaGas has entered into negotiations with a number of producers and other suppliers and expects to underpin at least 40 percent of RIPET's annual expected capacity under tolling arrangements with producers and other suppliers.

AltaGas LPG and Astomos Energy Corporation (Astomos) have entered into a multi-year agreement for the purchase of at least 50 percent of the 1.2 million tonnes per annum of propane expected to be available to be shipped from RIPET each year. Commercial discussions with Astomos and several third party off-takers for further capacity commitments are proceeding.

Construction of RIPET commenced during the second quarter of 2017 and will proceed pursuant to an agreement with RILE LP adopting AltaGas' self-perform model that AltaGas successfully used to build its other projects on time and on budget. Crews are currently working to pour the concrete outer wall for the propane tank, with the fourth of eight concrete pours underway and the final pour scheduled near the end of 2017. Fabrication for the inner steel tank roof is also underway and installation of the inner steel tank will begin. The balance of plant fabrication and civil work is on track and the first modules are scheduled to arrive in the first quarter of 2018. RIPET 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. Brining for cavern development is expected to begin in late 2017 or early 2018. On January 30, 2017, the Supreme Court of Nova Scotia released a decision setting aside the April 18, 2016 decision of the Minister of Environment (the Minister) 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.

Marquette Connector Pipeline

On August 23, 2017, the MPSC approved SEMCO Gas' application to construct, own, and operate the 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. The MCP is estimated to cost between US$135 to $140 million. Engineering and property acquisitions are expected to begin in 2018 and construction is expected to begin in 2019, with an anticipated in-service date in mid-2020.

Pomona Facility

Following the 2016 commissioning of the Pomona Energy Storage Facility, AltaGas received California Independent System Operator (CAISO) certification of regulation which allows the facility to also participate in the ancillary services market. AltaGas continues to evaluate a future expansion of the facility based on Southern California Edison's (SCE) potential procurement of additional energy storage in the Los Angeles Basin to further improve system reliability, including in relation to the ongoing concerns over the Aliso Canyon gas storage facility.

Renewable and Energy Storage Development

As Publicly Owned Utilities (POUs), Investor Owned Utilities (IOUs), and Community Choice Aggregators (CCAs) add renewable resources to meet California's renewable portfolio standard obligations as well as the California Public Utilities Commission's energy storage procurement target of 1,325 MW, sites with strong solar and wind characteristics as well as cost effective transmission interconnections are in high demand. AltaGas expects that its greenfield and brownfield development sites throughout California, which are well suited for renewable, energy storage or both renewable and energy storage projects, could attract multi-year power purchase agreements through either the standard request for proposal (RFP) process or bilateral discussions.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2017**	2016	**2017**	2016
Normalized EBITDA	**$ 190**	$ 176	**$ 584**	$ 507
Add (deduct):				
Transaction costs related to acquisitions	**(9)**	—	**(50)**	(2)
Unrealized gains (losses) on risk management contracts	**(25)**	4	**(47)**	1
Unrealized gains (losses) on long-term investments	**5**	1	**(3)**	2
Gains (losses) on sale of assets	**—**	—	**(3)**	4
Dilution loss on investment accounted for by the equity method	**—**	—	**—**	(1)
Provision on assets	**—**	—	**(1)**	—
Provision on investment accounted for by the equity method	**—**	(1)	**—**	(5)
Energy export development costs	**—**	—	**—**	(1)
Accretion expenses	**(3)**	(3)	**(8)**	(8)
Foreign exchange gains	**—**	—	**2**	4
Restructuring costs	**—**	—	**—**	(7)
Recovery of pipeline looping project development costs at PNG	**—**	7	**—**	7
EBITDA	**$ 158**	$ 184	**$ 474**	$ 501
Add (deduct):				
Depreciation and amortization	**(69)**	(67)	**(211)**	(202)
Interest expense	**(40)**	(39)	**(127)**	(111)
Income tax expense	**(14)**	(17)	**(43)**	(27)
Net income after taxes (GAAP financial measure)	**$ 35**	$ 61	**$ 93**	$ 161

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 and on long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, accretion expenses related to asset retirement obligations and the Northwest Transmission Line liability, foreign exchange gains (losses), provisions on assets and on investment accounted for by the equity method, dilution loss on an investment accounted for by the equity method, recovery of development costs for the PNG Pipeline Looping Project, and restructuring costs. Normalized EBITDA also includes an adjustment for certain non-capitalizable project development costs related to energy export projects. 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 September 30 2017	2016	Nine Months Ended September 30 2017	2016
Normalized net income	**$ 48**	$ 38	**$ 141**	$ 105
Add (deduct) after-tax:				
Transaction costs related to acquisitions	**(9)**	—	**(39)**	(1)
Unrealized gains (losses) on risk management contracts	**(22)**	2	**(43)**	1
Unrealized gains (losses) on long-term investments	**5**	1	**(3)**	1
Gains (losses) on sale of assets	**—**	—	**(3)**	15
Dilution loss on investment accounted for by the equity method	**—**	—	**—**	(1)
Provision on assets	**—**	—	**(1)**	—
Provision on investment accounted for by the equity method	**—**	—	**—**	(2)
Recovery of pipeline looping project development costs at PNG	**—**	5	**—**	5
Restructuring costs	**—**	—	**—**	(5)
Financing costs associated with the bridge facility	**(4)**	—	**(11)**	—
Net income applicable to common shares (GAAP financial measure)	**$ 18**	$ 46	**$ 41**	$ 118

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts and on long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on assets and on investment accounted for by the equity method, dilution loss on investment accounted for by the equity method, financing costs associated with the bridge facility for the pending WGL Acquisition, recovery of development costs for the PNG Pipeline Looping Project, and restructuring costs. 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 September 30 2017	2016	Nine Months Ended September 30 2017	2016
Normalized funds from operations	**$ 143**	$ 137	**$ 436**	$ 383
Add (deduct):				
Transaction and financing costs related to acquisitions	**(12)**	—	**(54)**	(2)
Recovery of pipeline looping project development costs at PNG	**—**	5	**—**	5
Restructuring costs	**—**	—	**—**	(7)
Funds from operations	**131**	142	**382**	379
Add (deduct):				
Net change in operating assets and liabilities	**(42)**	(65)	**15**	(56)
Asset retirement obligations settled	**—**	(1)	**(3)**	(2)
Cash from operations (GAAP financial measure)	**$ 89**	$ 76	**$ 394**	$ 321

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 and financing costs related to acquisitions, recovery of development costs for the PNG Pipeline Looping Project, and restructuring costs.

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]		Three Months Ended September 30				Nine Months Ended September 30		
($ millions)		**2017**		2016		**2017**		2016
Gas	**$**	**51**	$	42	**$**	**159**	$	114
Power		**106**		104		**232**		222
Utilities		**38**		33		**208**		187
Sub-total: Operating Segments		**195**		179		**599**		523
Corporate		**(5)**		(3)		**(15)**		(16)
	$	**190**	$	176	**$**	**584**	$	507

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

GAS

OPERATING STATISTICS

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Extraction inlet gas processed (Mmcf/d) [1]	**946**	989	**966**	900
FG&P inlet gas processed (Mmcf/d) [1]	**376**	286	**375**	294
Total inlet gas processed (Mmcf/d) [1]	**1,322**	1,275	**1,341**	1,194
Extraction ethane volumes (Bbls/d) [1]	**27,229**	32,159	**27,954**	29,532
Extraction NGL volumes (Bbls/d) [1] [2]	**36,797**	33,350	**36,390**	33,139
Total extraction volumes (Bbls/d) [1] [3]	**64,026**	65,509	**64,344**	62,671
Frac spread - realized ($/Bbl) [1] [4]	**14.96**	6.29	**11.61**	8.02
Frac spread - average spot price ($/Bbl) [1] [5]	**21.28**	6.29	**16.54**	8.21

(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 September 30, 2017 decreased by 43 Mmcf/d, compared to the same period in 2016. The decrease was primarily due to lower volumes at Younger as a result of third party outages upstream of the facility. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended September 30, 2017 increased by 90 Mmcf/d primarily due to volumes received at the Townsend Facility. Gordondale inlet was flat despite a planned two week turnaround occurring in the third quarter of 2017 due to increased utilization following the modification of the take-or-pay agreement with Birchcliff in the second quarter of 2017.

Inlet gas volumes processed at the extraction facilities for the nine months ended September 30, 2017 increased by 66 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, due to reinjections and temporary shut-ins driven by low commodity prices in the same period in 2016. Inlet gas volumes processed at the FG&P facilities for the nine months ended September 30, 2017 increased by 81 Mmcf/d primarily due to volumes received at the Townsend Facility, partially offset by the impact from the Tidewater Gas Asset Disposition on February 29, 2016.

Average ethane volumes for the three months ended September 30, 2017 decreased by 4,930 Bbls/d, while average NGL volumes increased by 3,447 Bbls/d, compared to the same period in 2016. Lower ethane volumes were as a result of rejecting production at PEEP and EEEP due to uneconomic pricing. Higher NGL volumes were primarily due to volumes produced at the Townsend Facility.

Average ethane volumes for the nine months ended September 30, 2017 decreased by 1,578 Bbls/d compared to the same period in 2016. Lower ethane volumes were primarily due to rejecting production at PEEP due to uneconomic pricing in the second and third quarter of 2017, partially offset by normal operations at JEEP compared to temporary plant shut-ins and reinjections driven by lower commodity prices in the first half of 2016. Average NGL volumes increased by 3,251 Bbls/d compared to the same period in 2016. Higher NGL volumes were primarily due to normal operations at EEEP compared to temporary plant shut-ins and reinjections driven by lower commodity prices in the same period in 2016, and volumes produced at the Townsend Facility.

Three Months Ended September 30

The Gas segment reported normalized EBITDA of $51 million in the third quarter of 2017, compared to $42 million in the same quarter of 2016. The increase in normalized EBITDA was due to higher realized frac spreads and frac exposed volumes, higher equity earnings from Petrogas, and a full quarter of contributions from the Townsend Facility, partially offset by the sale of the EDS and JFP transmission assets in the first quarter of 2017, and lower ethane revenue in the third quarter of 2017 due to lower volumes and pricing. During the third quarter of 2017, AltaGas recorded equity earnings of $6 million from Petrogas, compared to $nil in the same quarter of 2016. The increase in equity earnings from Petrogas was mainly due to higher netbacks on export shipments from the Ferndale Terminal and strengthening of Petrogas' business lines supporting the upstream sector.

During the third quarter of 2017, AltaGas hedged approximately 5,800 Bbls/d of NGL volumes at an average price of $23/Bbl excluding basis differentials. During the third quarter of 2016, AltaGas hedged 790 Bbls/d of NGL at an average price of $33/Bbl, excluding basis differentials. The average indicative spot NGL frac spread in the third quarter of 2017 was approximately $21/Bbl, compared to $6/Bbl in the third quarter of 2016. The realized frac spread of approximately $15/Bbl in the third quarter of 2017 (2016 - $6/Bbl) was higher than the same quarter in 2016 due to improved commodity prices.

Nine Months Ended September 30

The Gas segment reported normalized EBITDA of $159 million in the nine months ended September 30, 2017, compared to $114 million in the same period of 2016. The increase in normalized EBITDA was due to the Townsend Facility entering commercial operations in the third quarter of 2016, higher realized frac spread and frac exposed volumes, higher equity earnings from Petrogas, higher NGL marketing revenue, and higher natural gas storage margins, partially offset by the impact of the sale of the EDS and JFP transmission assets, planned turnarounds at EEEP and the Turin facility in the second quarter of 2017, lower ethane revenue due to lower volumes, and lower average realized rates at the Blair Creek facility. During the nine months ended September 30, 2017, AltaGas recorded equity earnings of $19 million from Petrogas, compared to $7 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 increased contributions from all of Petrogas' business segments during the nine months ended September 30, 2017.

During the nine months ended September 30, 2017, AltaGas hedged approximately 5,500 Bbls/d of NGL volumes at an average price of $23/Bbl, excluding basis differentials. During the nine months ended September 30, 2016, AltaGas hedged 440 Bbls/d of NGL at an average price of $31/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for the nine months ended September 30, 2017 was approximately $17/Bbl compared to $8/Bbl in the same period of 2016. The realized frac spread of $12/Bbl in the nine months ended September 30, 2017 (2016 - $8/Bbl) was higher than the same period in 2016 due to improved commodity prices.

At the end of May 2017, AltaGas concluded that it no longer exercised significant influence over Tidewater. Consequently, AltaGas ceased accounting for the investment under the equity method and now accounts for the Tidewater common shares at fair value. As a result, AltaGas recorded an unrealized pre-tax loss of approximately $8 million in the second quarter of 2017. Subsequent changes in fair value are recognized in the Consolidated Statement of Income.

During the nine months ended September 30, 2017, AltaGas recognized a pre-tax loss of $3 million on the sale of the EDS and JFP transmission assets while during the nine months ended September 30, 2016, AltaGas recognized a pre-tax gain of $5 million on the Tidewater Gas Asset Disposition.

POWER

OPERATING STATISTICS

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Renewable power sold (GWh)	**681**	670	**1,328**	1,356
Conventional power sold (GWh)	**992**	587	**1,785**	1,576
Renewable capacity factor (%)	**70.3**	70.2	**43.5**	45.9
Contracted conventional equivalent availability factor (%) (1)	**99.6**	99.3	**98.6**	96.5

(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 three months ended September 30, 2017, the volume of renewable power sold increased by 11 GWh and the volume of conventional power sold increased by 405 GWh, compared to the same period in 2016. The increase in renewable volumes was due to increased wind generation at the Bear Mountain wind facility and the addition of the Pomona Energy Storage Facility. The increase in conventional volumes was due to increased run time at the San Joaquin Facilities and Blythe as a result of increased dispatch under the respective power purchase agreements and greater operational and fuel flexibility at Blythe.

The renewable capacity factor for the three months ended September 30, 2017 was relatively unchanged. The contracted conventional equivalent availability factor was higher for the three months ended September 30, 2017 as a result of increased availability at Blythe.

During the nine months ended September 30, 2017, the volume of renewable power sold decreased by 28 GWh and the volume of conventional power sold increased by 209 GWh, compared to the same period in 2016. The decrease in renewable volumes was due to seasonally average start to freshet flows in early 2017 at the Northwest Hydro Facilities as compared to an early start in 2016, partially offset by the addition of the Pomona Energy Storage Facility, and stronger wind generation at the Bear Mountain wind facility. The increase in conventional volumes was due to volume contributions from the San Joaquin Facilities, higher dispatch at Blythe as the facility has run to provide system reliability to the CAISO network and increased its cost effectiveness by adding a second source of gas supply and expanding its operating limits. The increase was partially offset by the impact of the termination of the Sundance B PPAs effective March 8, 2016.

The renewable capacity factor for the nine months ended September 30, 2017 decreased due to seasonally average start to freshet flows in early 2017 at the Northwest Hydro Facilities as compared to an early start in 2016. The variance for the contracted conventional availability factor for the nine months ended September 30, 2017 was due to the same reason as noted above for the three months ended September 30, 2017.

Three Months Ended September 30

The Power segment reported normalized EBITDA of $106 million during the three months ended September 30, 2017, compared to $104 million in the same period of 2016. Normalized EBITDA increased as a result of contributions from the Pomona Energy Storage Facility, higher continuous dispatch at the San Joaquin Facilities and Blythe, and lower operating expenses at U.S. conventional facilities due to effective cost control, partially offset by the weaker U.S. dollar, and lower realized gains on hedges.

Nine Months Ended September 30

The Power segment reported normalized EBITDA of $232 million in the nine months ended September 30, 2017, compared to $222 million in the same period of 2016. Normalized EBITDA increased as a result of the absence of equity losses from the Sundance B PPAs, contributions from the Pomona Energy Storage Facility, lower operating expenses at U.S. conventional facilities due to effective cost control, and stronger wind generation at the Bear Mountain wind facility, partially offset by lower realized gains on hedges and a one-time credit received by AltaGas San Joaquin Energy Inc. in the second quarter of 2016 from Pacific Gas and Electric Company (PG&E) related to the San Bruno pipeline explosion on PG&E's natural gas pipeline in 2010.

During the nine months ended September 30, 2017, the Power segment disposed of certain non-core development stage wind assets for a pre-tax gain of $1 million, which was largely offset by the provision on certain non-core development stage gas-fired peaking assets in Alberta of $1 million. During the nine months ended September 30, 2016, 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 September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Canadian utilities				
Natural gas deliveries - end-use (PJ)(1)	**3.7**	3.2	**22.1**	19.2
Natural gas deliveries - transportation (PJ)(1)	**1.3**	1.1	**4.7**	4.5
U.S. utilities				
Natural gas deliveries - end-use (Bcf)(1)	**5.9**	5.4	**46.5**	42.5
Natural gas deliveries - transportation (Bcf)(1)	**10.9**	11.0	**37.8**	37.3
Service sites (2)	**575,602**	568,628	**575,602**	568,628
Degree day variance from normal - AUI (%) (3)	**(16.9)**	(8.4)	**(4.2)**	(19.4)
Degree day variance from normal - Heritage Gas (%) (3)	**(20.4)**	(7.4)	**(3.4)**	(4.4)
Degree day variance from normal - SEMCO Gas (%) (4)	**5.7**	(57.6)	**(10.7)**	(6.1)
Degree day variance from normal - ENSTAR (%) (4)	**(16.6)**	(36.1)	**2.2**	(23.8)

(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 September 30

The Utilities segment reported normalized EBITDA of $38 million during the three months ended September 30, 2017, compared to $33 million in the same quarter of 2016. The increase was mainly due to colder weather in Michigan and Alaska, the rate increase in 2016 at ENSTAR, the absence of the true-up from the third quarter of 2016 related to the approval of Heritage Gas' customer retention program, and lower operating expenses at certain Utilities. The increase was partially offset by warmer weather in Alberta and Nova Scotia, lower interruptible storage service revenue at CINGSA, and the impact of the weaker U.S. dollar.

Nine Months Ended September 30

The Utilities segment reported normalized EBITDA of $208 million during the nine months ended September 30, 2017, compared to $187 million in the same period of 2016. The increase was mainly due to colder weather in Alaska, Alberta, and Nova Scotia, customer and rate growth primarily due to the rate increase in 2016 at ENSTAR, higher customer usage, favorable transport revenue primarily at PNG, lower operating expenses at certain Utilities, an early termination payment of $2 million from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract, and insurance proceeds received by SEMCO's non-regulated operations. These variances were partially offset by warmer weather in Michigan, lower interruptible storage service revenue at CINGSA, and the impact of the weaker U.S. dollar.

CORPORATE

Three Months Ended September 30

In the Corporate segment, normalized EBITDA for the third quarter of 2017 was a loss of $5 million, compared to a $3 million loss in the same quarter of 2016. The increase was mainly due to higher software and information technology related costs and professional and consulting fees incurred during the quarter.

Nine Months Ended September 30

In the Corporate segment, normalized EBITDA for the nine months ended September 30, 2017 was a loss of $15 million, compared to a $16 million loss in the same period of 2016. The decrease was a result of a number of factors including lower employee-related costs and lower professional and consulting fees, partially offset by higher software and information technology related costs.

INVESTED CAPITAL

										Three Months Ended September 30, 2017
($ millions)		**Gas**		**Power**		**Utilities**		**Corporate**		**Total**
Invested capital:										
Property, plant and equipment	**$**	**113**	**$**	**1**	**$**	**32**	**$**	**1**	**$**	**147**
Intangible assets		**—**		**11**		**—**		**—**		**11**
Long-term investments		**3**		**—**		**—**		**—**		**3**
Contributions from non-controlling interest		**(6)**		**—**		**—**		**—**		**(6)**
Invested capital		**110**		**12**		**32**		**1**		**155**
Disposals:										
Property, plant and equipment		**—**		**—**		**—**		**—**		**—**
Net invested capital	**$**	**110**	**$**	**12**	**$**	**32**	**$**	**1**	**$**	**155**

										Three Months Ended September 30, 2016
($ millions)		Gas		Power		Utilities		Corporate		Total
Invested capital:										
Property, plant and equipment	$	31	$	23	$	25	$	1	$	80
Intangible assets		—		12		1		1		14
Long-term investments		14		—		—		—		14
Invested capital		45		35		26		2		108
Disposals:										
Property, plant and equipment		—		—		—		—		—
Net invested capital	$	45	$	35	$	26	$	2	$	108

During the third quarter of 2017, AltaGas' invested capital was $155 million, compared to $108 million in the same quarter of 2016. The increase in invested capital was mainly due to costs incurred in the third quarter of 2017 for the construction of Townsend 2A, RIPET, and the first train of the North Pine Facility and the North Pine Pipelines, as well as the costs related to the Gordondale facility turnaround. Contributions from non-controlling interest represents Vopak's share of construction costs related to RIPET.

During the third quarter of 2017, AltaGas paid $11 million (2016 - $11 million) to BC Hydro in support of the construction and operation of the Northwest Transmission Line.

The invested capital in the third quarter of 2017 included maintenance capital of $6 million (2016 - $1 million) in the Gas segment and $1 million (2016 - $2 million) in the Power segment. The maintenance capital for the Gas segment was mainly related to the costs incurred on the Gordondale facility turnaround in the third quarter of 2017.

($ millions)		Gas		Power		Utilities		Corporate		Total
										Nine Months Ended September 30, 2017
Invested capital:										
Property, plant and equipment	**$**	**247**	**$**	**16**	**$**	**80**	**$**	**1**	**$**	**344**
Intangible assets		**1**		**13**		**1**		**2**		**17**
Long-term investments		**17**		**—**		**—**		**—**		**17**
Contributions from non-controlling interest		**(12)**		**—**		**—**		**—**		**(12)**
Invested capital		**253**		**29**		**81**		**3**		**366**
Disposals:										
Property, plant and equipment		**(67)**		**(2)**		**(1)**		**—**		**(70)**
Net invested capital	**$**	**186**	**$**	**27**	**$**	**80**	**$**	**3**	**$**	**296**

($ millions)		Gas		Power		Utilities		Corporate		Total
										Nine Months Ended September 30, 2016
Invested capital:										
Property, plant and equipment	$	262	$	45	$	69	$	3	$	379
Intangible assets		2		14		1		3		20
Long-term investments		235		—		—		—		235
Invested capital		499		59		70		6		634
Disposals:										
Property, plant and equipment		(94)		—		(1)		—		(95)
Net invested capital	$	405	$	59	$	69	$	6	$	539

During the nine months ended September 30, 2017, AltaGas' invested capital was $366 million, compared to $634 million in the same period of 2016. The decrease in property, plant and equipment was mainly due to the costs incurred during the nine months ended September 30, 2016 to complete the construction of the Townsend Facility as well as the purchase of the remaining 51 percent interest in EEEP, partially offset by the costs incurred during the nine months ended September 30, 2017 for the construction of Townsend 2A, RIPET, and the first train of the North Pine Facility and the North Pine Pipelines, as well as the costs incurred on the Gordondale facility turnaround. The decrease in long-term investments during the nine months ended September 30, 2017 was mainly due to the investment made in Tidewater in the first quarter of 2016 as well as the investment made in Petrogas Preferred Shares in the second quarter of 2016, partially offset by the contribution of $17 million to AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) in 2017 to fund the scheduled principal and interest repayments of a note payable related to AIJVLP's acquisition of its interest in Petrogas in 2014. The disposals of property, plant and equipment during the nine months ended September 30, 2017 primarily related to the sale of the EDS and JFP transmission assets, while during the nine months ended September 30, 2016 the disposals of property, plant and equipment related to the Tidewater Gas Asset Disposition.

The invested capital for the nine months ended September 30, 2017 included maintenance capital of $8 million (2016 - $1 million) in the Gas segment and $7 million (2016 - $11 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 September 30, 2017 and December 31, 2016, the fair values of the Corporation's derivatives were as follows:

($ millions)	**September 30, 2017**	December 31, 2016
Natural gas	**$ —**	$ 4
Storage optimization	**—**	(3)
NGL frac spread	**(13)**	(12)
Power	**14**	30
Foreign exchange	**4**	—
Net derivative asset	**$ 5**	$ 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 Statement 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 nine months ended September 30, 2017 was approximately $22/MWh (2016 – $17/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 nine months ended September 30, 2017 was approximately $17/Bbl (2016 – $8/Bbl). The average NGL frac spread realized by AltaGas for nine months ended September 30, 2017 was approximately $12/Bbl inclusive of basis differentials (2016 - $8/Bbl). For the remainder of 2017, AltaGas currently has frac hedges in place to hedge approximately 6,500 Bbls/d at an average price of $24/Bbl, excluding basis differentials. AltaGas also entered into frac hedges to hedge approximately 5,000 Bbls/d at an average price of $30/Bbl, excluding basis differentials, for calendar year 2018.

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 to the extent that AltaGas has U.S. dollar-denominated debt and preferred shares outstanding. 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 September 30, 2017, management designated US$10 million of outstanding U.S. dollar denominated long-term debt to hedge against the currency translation effect of its foreign investments (December 31, 2016 - US$301 million). 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 and nine months ended September 30, 2017, AltaGas incurred after-tax unrealized gains of $nil and $7 million, respectively arising from the translation of debt in other comprehensive income (for the three and nine months ended September 30, 2016, after-tax unrealized loss of $4 million and after tax unrealized gain of $41 million, respectively).

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 approximately US$1.2 billion. These foreign currency option contracts do not qualify for hedge accounting. Therefore, all changes in fair value are recognized in net income. For the three and nine months ended September 30, 2017, unrealized losses of $10 million and $32 million, respectively were recognized under "unrealized gains and losses from risk management contracts" in relation to these contracts.

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:

($ millions)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Natural gas	**$ (2)**	$ (1)	**$ (4)**	$ (2)
Storage optimization	**—**	1	**3**	(3)
NGL frac spread	**(10)**	(1)	**(1)**	(3)
Power	**(3)**	5	**(12)**	8
Foreign exchange	**(10)**	—	**(33)**	1
	$ (25)	$ 4	**$ (47)**	$ 1

Please refer to Note 19 of the 2016 Annual Consolidated Financial Statements and Note 11 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2017 for further details regarding AltaGas' risk management activities.

LIQUIDITY

($ millions)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Cash from operations	**$ 89**	$ 76	**$ 394**	$ 321
Investing activities	**(205)**	(136)	**(380)**	(618)
Financing activities	**(15)**	(13)	**(8)**	8
Increase (decrease) in cash and cash equivalents	**$ (131)**	$ (73)	**$ 6**	$ (289)

Cash from Operations

Cash from operations increased by $73 million for the nine months ended September 30, 2017 compared to the same period in 2016, reflecting the same drivers as normalized net income and the favorable variance in net change in operating assets and liabilities, partially offset by the transaction costs incurred on the pending WGL Acquisition. The favorable variance in net change in operating assets and liabilities was primarily due to higher cash inflow in 2017 relating to changes in inventory and accounts payable at the Utilities due to weather, changes in accounts payable at Corporate related to the pending WGL Acquisition, and reimbursement for refundable payments. These increases in cash flow were partially offset by a decrease in certain regulatory liabilities, changes in accounts payable for Energy Services due to gas prices, and higher prepayments on long-term service agreements related to RIPET.

Working Capital

($ millions except current ratio)	September 30, 2017	December 31, 2016
Current assets	**$ 543**	$ 739
Current liabilities	**633**	996
Working deficiency	**$ (90)**	$ (257)
Working capital ratio	**0.86**	0.74

The improvement in the working capital ratio was primarily due to a lower current portion of long-term debt outstanding, and a decrease in short-term debt and accounts payable as compared to December 31, 2016, partially offset by a decrease in accounts receivable and inventory as well as the completion of the sale of the EDS and JFP transmission assets to Nova Chemicals, which were previously classified as assets held for sale. 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 nine months ended September 30, 2017 was $380 million, compared to $618 million in the same period in 2016. Investing activities for the nine months ended September 30, 2017 primarily included expenditures of approximately $359 million for property, plant, and equipment, approximately $36 million for derivative contracts, approximately $17 million of contributions to AltaGas' equity investments, approximately $17 million in expenditures for intangible assets, and a $13 million loan to Petrogas under the $100 million interest bearing secured loan facility provided to Petrogas, partially offset by cash proceeds of approximately $70 million, net of transaction costs, primarily from the sale of the EDS and JFP transmission assets. Investing activities for the nine months ended September 30, 2016 primarily included AltaGas' $150 million investment in Petrogas Preferred Shares, a $40 million loan to Petrogas under the $100 million interest bearing secured loan facility provided to Petrogas, approximately $21 million for the purchase of EEEP, approximately $400 million for property, plant, and equipment, and approximately $19 million for intangible assets, 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 nine months ended September 30, 2017 was $8 million, compared to cash from financing activities of $8 million in the same period in 2016. Financing activities for the nine months ended September 30, 2017 were primarily comprised of net proceeds from the issuance of preferred shares of $293 million and common shares of $179 million (mainly from common shares issued through DRIP), borrowings under the credit facilities of $749 million, and proceeds from the sale of a non-controlling interest in RIPET to Vopak of $24 million, partially offset by repayments of long-term debt and short-term debt of $838 million and $102 million, respectively. Financing activities for the nine months ended September 30, 2016 were primarily comprised of net proceeds from the issuance of common shares of $545 million (including common shares issued through DRIP), net proceeds from the issuance of MTNs of $348 million, and borrowings from credit facilities of $293 million, partially offset by the repayment of $851 million of long-term debt and $55 million of short-term debt. Total dividends paid to common and preferred shareholders of AltaGas for the nine months ended September 30, 2017 were $312 million (2016 - $265 million), of which $175 million was reinvested through DRIP (2016 - $116 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 DRIP for the nine months ended September 30, 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 12 of the unaudited interim condensed Consolidated Financial Statements for the three and nine months ended September 30, 2017 for more information about 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 the 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.

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($ millions)		September 30, 2017		December 31, 2016
Short-term debt	$	18	$	129
Current portion of long-term debt		183		383
Long-term debt[1]		3,453		3,367
Total debt		3,654		3,879
Less: cash and cash equivalents		(25)		(19)
Net debt	$	3,629	$	3,860
Shareholders' equity		4,613		4,581
Non-controlling interests		62		35
Total capitalization	$	8,304	$	8,476
Debt-to-total capitalization (%)		44		46

(1) Net of debt issuance costs of $12 million as at September 30, 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.

On October 4, 2017, AltaGas issued an aggregate of $450 million of MTNs consisting of $200 million of MTNs with a coupon rate of 3.98 percent maturing on October 4, 2027, and $250 million of MTNs with a coupon rate of 4.99 percent maturing on October 4, 2047. The net proceeds were used to pay down existing indebtedness and for general corporate purposes.

As at September 30, 2017, AltaGas' total debt primarily consisted of outstanding MTNs of $2.5 billion (December 31, 2016 - $2.8 billion), PNG debenture notes of $36 million (December 31, 2016 - $43 million), SEMCO long-term debt of $459 million (December 31, 2016 - $500 million) and $690 million drawn under the bank credit facilities (December 31, 2016 - $501 million). In addition, AltaGas had $112 million of letters of credit (December 31, 2016 - $161 million) outstanding.

As at September 30, 2017, AltaGas' total market capitalization was approximately $5.0 billion based on approximately 173 million common shares outstanding and a closing trading price on September 30, 2017 of $28.74 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended September 30, 2017 was 2.0 times (12 months ended September 30, 2016 – 1.8 times).

Credit Facilities

($ millions)		Borrowing capacity		Drawn at September 30, 2017		Drawn at December 31, 2016
Demand operating facilities	$	70	$	4	$	4
Extendible revolving letter of credit facility		150		41		49
Letter of credit demand facility		150		63		104
PNG operating facility		25		6		10
AltaGas Ltd. revolving credit facility [1]		1,400		665		378
AltaGas Ltd. revolving US$300 million credit facility [1] [2]		374		12		—
SEMCO Energy US$150 million unsecured credit facility [1] [2]		187		11		117
	$	2,356	$	802	$	662

(1) Amount drawn at September 30, 2017 converted at the month-end rate of 1 U.S. dollar = 1.2480 Canadian dollar (December 31, 2016 - 1 U.S. dollar = 1.3427 Canadian dollar).

(2) Borrowing capacity was converted at the September 30, 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 September 30, 2017**
Bank debt-to-capitalization(1)	not greater than 65 percent	43.6%
Bank EBITDA-to-interest expense (1) (2)	not less than 2.5x	3.9
Bank debt-to-capitalization (SEMCO)(3)	not greater than 60 percent	39.1%
Bank EBITDA-to-interest expense (SEMCO)(3)	not less than 2.25x	7.5

(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 September 7, 2017, 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. As at September 30, 2017, $5 billion was available under the base shelf prospectus. On October 4, 2017, AltaGas issued an aggregate of $450 million of MTNs, decreasing the amount available under the base shelf prospectus to approximately $4.6 billion.

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 October 13, 2017
Issued and outstanding	
Common shares	173,048,505
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	4,575,636
Share options exercisable	3,211,008

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 was paid on June 30, 2017 in the amount of $0.4384 per Series K preferred share. Unless otherwise redeemed or converted pursuant to the terms of the Series K preferred shares, 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.

On September 30, 2017, the annual fixed dividend rate for the Series C preferred shares was reset to 5.29 percent. The dividend rate will reset on September 30, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.58 percent.

On October 18, 2017, the Board of Directors approved an increase in the monthly dividend by $0.0075 per common share to $0.1825 ($2.19 per common share annualized) effective for the November dividend, payable on December 15, 2017, a 4.3 percent increase.

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		**0.52500**		0.49500
Third quarter		**0.52500**		0.51500
Fourth quarter		**—**		0.52500
Total	**$**	**1.57500**	$	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**		0.21125
Third quarter		**0.21125**		0.21125
Fourth quarter		**—**		0.21125
Total	**$**	**0.63375**	$	0.84500

Series B Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2017**		2016
First quarter	**$**	**0.19541**	$	0.19269
Second quarter		**0.19571**		0.19393
Third quarter		**0.20101**		0.20109
Fourth quarter		**—**		0.19921
Total	**$**	**0.59213**	$	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**		0.27500
Third quarter		**0.27500**		0.27500
Fourth quarter		**—**		0.27500
Total	**$**	**0.82500**	$	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**		0.31250
Third quarter		**0.31250**		0.31250
Fourth quarter		**—**		0.31250
Total	**$**	**0.93750**	$	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**		0.296875
Third quarter		**0.296875**		0.296875
Fourth quarter		**—**		0.296875
Total	**$**	**0.890625**	$	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**		0.328125
Third quarter		**0.328125**		0.328125
Fourth quarter		**—**		0.328125
Total	**$**	**0.984375**	$	1.448245

Series K Preferred Share Dividends

Year ended December 31

($ per preferred share)		2017		2016
First quarter	$	**—**	$	—
Second quarter		**0.43840**		—
Third quarter		**0.31250**		—
Fourth quarter		**—**		—
Total	**$**	**0.75090**	$	—

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 focus 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. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A 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 with make-up rights as well as any contracts that give the customer a material right. Based on the analysis completed to-date, AltaGas does not expect a material impact to revenue recognition. AltaGas has started a process to compile the information needed to meet the new disclosure requirements and is assessing the recently released exposure draft 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, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. 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 that 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 transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The 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. The adoption of this ASU is not expected to have a material impact on AltaGas' 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.

In May 2017, FASB issued ASU No. 2017-09 "Compensation – Stock Compensation: Scope of Modifications Accounting". The amendments in this ASU provide guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The 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. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In August 2017, FASB issued ASU No. 2017-12 "Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities". The amendments in this ASU improves the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and make certain targeted improvements to simplify the application of hedge accounting. The amendments in this ASU are effective for annual periods beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. 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 and nine months ended September 30, 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 September 30, 2017 and concluded that as at September 30, 2017, AltaGas' DCP and ICFR were effective.

During the third quarter of 2017, there were no changes made to AltaGas' ICFR that materially 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)	**Q3-17**	Q2-17	Q1-17	Q4-16	Q3-16	Q2-16	Q1-16	Q4-15
Total revenue	**502**	539	771	661	492	426	611	580
Normalized EBITDA [(2)]	**190**	166	228	194	176	153	178	173
Net income (loss) applicable to common shares	**18**	(8)	32	38	46	16	55	(54)
($ per share)	**Q3-17**	Q2-17	Q1-17	Q4-16	Q3-16	Q2-16	Q1-16	Q4-15
Net income (loss) per common share								
Basic	**0.10**	(0.05)	0.19	0.23	0.28	0.10	0.38	(0.37)
Diluted	**0.10**	(0.05)	0.19	0.23	0.28	0.10	0.38	(0.37)
Dividends declared	**0.53**	0.53	0.53	0.53	0.52	0.50	0.50	0.50

(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 snow pack 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 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 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;
- The commissioning of the Pomona Energy Storage Facility on December 31, 2016;
- The closing of the sale of the EDS and the JFP transmission assets to Nova Chemicals in March of 2017; and
- Unrealized losses of $6 million, $16 million, and $10 million recorded during the first, second, and third quarters of 2017, respectively, related to the foreign currency option contracts entered into to mitigate the foreign exchange risks associated with the cash purchase price of WGL.

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, gains or losses on long-term investments, 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 from the fourth quarter of 2015 up until the end of the first quarter of 2017 as a result of the acquisition of the San Joaquin Facilities. The average debt balance decreased starting from the second quarter of 2017 as cash proceeds from the issuance of preferred shares and the sale of the EDS and JFP transmission assets were used to partially repay outstanding debt. During 2017, interest expense was also higher due to the financing costs associated with the bridge facility;
- 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;
- The unrealized loss of approximately $8 million recognized upon ceasing to account for the Tidewater investment using the equity method in the second quarter of 2017; and
- After-tax transaction costs of approximately $27 million, $4 million, and $9 million incurred in the first, second, and third quarters of 2017, respectively, related to the pending WGL Acquisition.

Consolidated Balance Sheets

(condensed and unaudited)

As at *($ millions)*		**September 30, 2017**		December 31, 2016
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**25.1**	$	19.0
Accounts receivable, net of allowances		**243.6**		338.8
Inventory *(note 5)*		**202.6**		221.0
Restricted cash holdings from customers		**7.7**		5.0
Regulatory assets		**1.4**		0.9
Risk management assets *(note 11)*		**32.8**		40.4
Prepaid expenses and other current assets		**29.4**		42.8
Assets held for sale *(note 4)*		**—**		70.7
		542.6		738.6
Property, plant and equipment		**6,710.9**		6,734.9
Intangible assets		**641.6**		694.3
Goodwill *(note 6)*		**814.8**		856.0
Regulatory assets		**321.5**		329.1
Risk management assets *(note 11)*		**16.4**		24.1
Deferred income taxes		**2.8**		2.8
Restricted cash holdings from customers		**7.5**		10.1
Long-term investments and other assets *(note 7)*		**305.0**		189.3
Investments accounted for by the equity method *(note 7)*		**568.9**		621.4
	$	**9,932.0**	$	10,200.6
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**303.5**	$	345.8
Dividends payable		**30.3**		29.2
Short-term debt		**18.1**		128.7
Current portion of long-term debt *(notes 9 and 11)*		**182.8**		383.4
Customer deposits		**31.9**		35.5
Regulatory liabilities		**5.9**		16.6
Risk management liabilities *(note 11)*		**32.7**		32.9
Other current liabilities		**28.1**		23.6
Liabilities associated with assets held for sale *(note 4)*		**—**		0.4
		633.3		996.1
Long-term debt *(notes 9 and 11)*		**3,453.0**		3,366.9
Asset retirement obligations		**81.2**		81.6
Deferred income taxes		**600.2**		621.7
Regulatory liabilities		**163.6**		170.5
Risk management liabilities *(note 11)*		**12.0**		12.6
Other long-term liabilities		**197.0**		206.3
Future employee obligations *(note 15)*		**117.4**		129.5
	$	**5,257.7**	$	5,585.2

As at *($ millions)*	**September 30, 2017**	December 31, 2016
Shareholders' equity		
Common shares, no par values, unlimited shares authorized; 2017 - 173.0 million and 2016 - 166.9 million issued and outstanding *(note 12)*	**$ 3,953.0**	$ 3,773.4
Preferred shares *(note 12)*	**1,280.4**	985.1
Contributed surplus	**22.2**	17.4
Accumulated deficit	**(828.5)**	(600.4)
Accumulated other comprehensive income (AOCI) *(note 10)*	**185.6**	405.1
Total shareholders' equity	**4,612.7**	4,580.6
Non-controlling interests	**61.6**	34.8
Total equity	**4,674.3**	4,615.4
	$ 9,932.0	$ 10,200.6

Variable interest entity (note 8).
Commitments, contingencies and guarantees (note 14).
Subsequent events (note 20).

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ millions except per share amounts)	Three months ended September 30 2017	Three months ended September 30 2016	Nine months ended September 30 2017	Nine months ended September 30 2016
REVENUE				
Regulated operations	**$ 151.6**	$ 146.2	**$ 773.4**	$ 709.7
Services	**249.3**	234.9	**672.2**	617.1
Sales	**125.9**	101.0	**412.2**	194.0
Other revenue	**—**	6.7	**0.1**	6.8
Unrealized gains (losses) on risk management contracts *(note 11)*	**(25.3)**	3.5	**(46.5)**	0.8
	501.5	492.3	**1,811.4**	1,528.4
EXPENSES				
Cost of sales, exclusive of items shown separately	**230.0**	196.0	**935.5**	648.9
Operating and administrative	**125.6**	113.6	**422.1**	378.3
Accretion expenses	**2.7**	2.8	**8.2**	8.3
Depreciation and amortization	**69.0**	67.0	**211.1**	201.7
Provisions on assets	**—**	—	**1.3**	—
	427.3	379.4	**1,578.2**	1,237.2
Income (loss) from equity investments	**7.3**	1.6	**24.4**	(3.4)
Other income *(notes 4 and 7)*	**6.7**	2.4	**2.3**	8.3
Foreign exchange gains	**0.4**	0.1	**1.8**	3.6
Interest expense				
Short-term debt	**(0.6)**	(1.9)	**(2.3)**	(2.1)
Long-term debt	**(38.9)**	(36.8)	**(124.2)**	(109.1)
Income before income taxes	**49.1**	78.3	**135.2**	188.5
Income tax expense (recovery) *(note 16)*				
Current	**11.3**	13.4	**32.9**	33.2
Deferred	**2.5**	3.9	**9.7**	(6.0)
Net income after taxes	**35.3**	61.0	**92.6**	161.3
Net income applicable to non-controlling interests	**2.2**	2.5	**6.4**	7.7
Net income applicable to controlling interests	**33.1**	58.5	**86.2**	153.6
Preferred share dividends	**(15.6)**	(12.1)	**(45.1)**	(36.0)
Net income applicable to common shares	**$ 17.5**	$ 46.4	**$ 41.1**	$ 117.6
Net income per common share *(note 13)*				
Basic	**$ 0.10**	$ 0.28	**$ 0.24**	$ 0.76
Diluted	**$ 0.10**	$ 0.28	**$ 0.24**	$ 0.76
Weighted average number of common shares outstanding (millions) *(note 13)*				
Basic	**171.9**	164.1	**169.9**	154.2
Diluted	**172.1**	164.6	**170.2**	154.6

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

(condensed and unaudited)

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2017**	2016	**2017**	2016
Net income after taxes	**$ 35.3**	$ 61.0	**$ 92.6**	$ 161.3
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation	**(103.9)**	22.2	**(198.2)**	(148.2)
Unrealized gain (loss) on net investment hedge *(note 11)*	**—**	(3.5)	**6.8**	40.7
Settlement of post-retirement benefit plan (PRB) *(note 15)*	**—**	—	**0.2**	—
Reclassification of actuarial loss and prior service costs on defined benefit and PRB plans to net income *(note 15)*	**0.2**	0.2	**0.5**	0.5
Unrealized gain (loss) on available-for-sale assets	**(8.0)**	3.0	**(25.5)**	19.1
Other comprehensive income (loss) from equity investees	**(2.2)**	1.5	**(3.3)**	0.5
Total other comprehensive income (loss) (OCI), net of taxes	**(113.9)**	23.4	**(219.5)**	(87.4)
Comprehensive income (loss) attributable to controlling interests and non-controlling interests, net of taxes	**$ (78.6)**	$ 84.4	**$ (126.9)**	$ 73.9
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$ 2.2**	$ 2.5	**$ 6.4**	$ 7.7
Controlling interests	**(80.8)**	81.9	**(133.3)**	66.2
	$ (78.6)	$ 84.4	**$ (126.9)**	$ 73.9

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

($ millions)		Nine months ended September 30 2017		2016
Common shares *(note 12)*				
Balance, beginning of period	$	3,773.4	$	3,168.1
Shares issued for cash on exercise of options		4.1		7.6
Shares issued under DRIP [1]		175.4		116.2
Deferred taxes on share issuance costs		0.1		0.2
Shares issued on public offering, net of issuance costs		—		422.2
Balance, end of period	$	3,953.0	$	3,714.3
Preferred shares *(note 12)*				
Balance, beginning of period	$	985.1	$	985.1
Series K issued		293.4		—
Deferred taxes on share issuance costs		1.9		—
Balance, end of period	$	1,280.4	$	985.1
Contributed surplus				
Balance, beginning of period	$	17.4	$	16.7
Share options expense		1.1		1.4
Exercise of share options		(0.3)		(0.7)
Forfeiture of share options		(0.1)		(0.2)
Adoption of ASU No. 2016-09 *(note 2)*		1.1		—
Sale of non-controlling interest *(note 8)*		3.0		—
Balance, end of period	$	22.2	$	17.2
Accumulated deficit				
Balance, beginning of period	$	(600.4)	$	(435.4)
Net income applicable to controlling interests		86.2		153.6
Common share dividends		(268.1)		(233.1)
Preferred share dividends		(45.1)		(36.0)
Adoption of ASU No. 2016-09 *(note 2)*		(1.1)		—
Balance, end of period	$	(828.5)	$	(550.9)
AOCI *(note 10)*				
Balance, beginning of period	$	405.1	$	433.5
Other comprehensive loss		(219.5)		(87.4)
Balance, end of period	$	185.6	$	346.1
Total shareholders' equity	$	4,612.7	$	4,511.8
Non-controlling interests				
Balance, beginning of period	$	34.8	$	34.9
Net income applicable to non-controlling interests		6.4		7.7
Sale of non-controlling interest *(note 8)*		20.0		—
Contributions from non-controlling interests to subsidiaries		5.9		—
Distributions by subsidiaries to non-controlling interests		(5.5)		(6.8)
Balance, end of period	$	61.6	$	35.8
Total equity	$	4,674.3	$	4,547.6

(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)

($ millions)	Three months ended September 30 **2017**	2016	Nine months ended September 30 **2017**	2016
Cash from operations				
Net income after taxes	**$ 35.3**	$ 61.0	**$ 92.6**	$ 161.3
Items not involving cash:				
Depreciation and amortization	**69.0**	67.0	**211.1**	201.7
Provisions on assets	**—**	—	**1.3**	—
Accretion expenses	**2.7**	2.8	**8.2**	8.3
Share-based compensation	**0.3**	0.3	**1.0**	1.2
Deferred income tax expense (recovery) *(note 16)*	**2.5**	3.9	**9.7**	(6.0)
Losses (gains) on sale of assets *(note 4)*	**—**	(0.1)	**2.6**	(4.2)
Loss (income) from equity investments	**(7.3)**	(1.6)	**(24.4)**	3.4
Unrealized losses (gains) on risk management contracts *(note 11)*	**25.3**	(3.5)	**46.5**	(0.8)
Unrealized losses (gains) on long-term investments *(note 7)*	**(4.6)**	(1.4)	**3.1**	(1.7)
Amortization of deferred financing costs	**3.1**	1.5	**13.8**	2.0
Other	**(1.3)**	(0.9)	**(3.5)**	(0.1)
Asset retirement obligations settled	**(0.3)**	(0.7)	**(3.0)**	(2.3)
Distributions from equity investments	**6.1**	11.9	**19.7**	13.6
Changes in operating assets and liabilities *(note 17)*	**(42.0)**	(64.5)	**15.4**	(55.8)
	$ 88.8	$ 75.7	**$ 394.1**	$ 320.6
Investing activities				
Business acquisitions, net of cash acquired	**—**	—	**—**	(20.0)
Acquisition of property, plant and equipment	**(179.0)**	(94.7)	**(358.5)**	(399.7)
Acquisition of intangible assets	**(12.0)**	(13.4)	**(16.7)**	(19.4)
Acquisition of investment in a publicly traded entity	**—**	—	**(7.0)**	—
Contributions to equity investments	**(2.5)**	(13.5)	**(16.8)**	(20.2)
Loan to affiliate, net of repayment	**(7.5)**	(15.0)	**(12.5)**	(40.0)
Change in restricted cash holdings from customers	**(3.9)**	0.3	**(3.0)**	1.4
Investment in Petrogas preferred shares	**—**	—	**—**	(150.0)
Payment for derivative contracts *(note 11)*	**—**	—	**(36.0)**	—
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**0.2**	0.7	**70.4**	30.4
	$ (204.7)	$ (135.6)	**$ (380.1)**	$ (617.5)
Financing activities				
Net issuance (repayment) of short-term debt	**22.1**	46.9	**(102.4)**	(55.1)
Issuance of long-term debt, net of debt issuance costs	**209.7**	28.9	**749.0**	640.9
Repayment of long-term debt	**(204.6)**	(51.0)	**(838.4)**	(850.8)
Dividends - common shares	**(90.1)**	(82.7)	**(267.0)**	(228.3)
Dividends - preferred shares	**(15.6)**	(12.1)	**(45.1)**	(37.1)
Distributions to non-controlling interests	**(1.0)**	(1.6)	**(5.5)**	(6.8)
Contributions from non-controlling interests	**5.9**	—	**5.9**	—
Net proceeds from shares issued on exercise of options	**0.3**	4.7	**3.8**	6.9
Net proceeds from issuance of common shares	**58.1**	54.3	**175.4**	538.4
Net proceeds from issuance of preferred shares	**—**	—	**293.4**	—
Proceeds from sale of non-controlling interest *(note 8)*	**—**	—	**24.1**	—
Other	**(0.1)**	—	**(1.6)**	—
	$ (15.3)	$ (12.6)	**$ (8.4)**	$ 8.1
Change in cash and cash equivalents	**(131.2)**	(72.5)	**5.6**	(288.8)
Effect of exchange rate changes on cash and cash equivalents	**0.2**	—	**0.5**	0.3
Cash and cash equivalents, beginning of period	**156.1**	77.4	**19.0**	293.4
Cash and cash equivalents, end of period	**$ 25.1**	$ 4.9	**$ 25.1**	$ 4.9

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 Ltd. (AltaGas or the Corporation) 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. The Corporation's long-term strategy is to grow in attractive areas and maintain a long-term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. AltaGas' business strategy is underpinned by the growing demand for clean energy with natural gas as a key fuel source. 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, natural gas and NGL 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 1,163 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 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, its subsidiaries, variable interest entities (VIEs) for which the Corporation is the primary beneficiary, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities. Investments in unconsolidated companies that AltaGas has significant influence over, but not control, are accounted for using the equity method.

All intercompany balances and transactions are eliminated on consolidation. 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 focus 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. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A 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 with make-up rights as well as any contracts that give the customer a material right. Based on the analysis completed to-date, AltaGas does not expect a material impact to revenue recognition. AltaGas has started a process to compile the information needed to meet the new disclosure requirements and is assessing the recently released exposure draft 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, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. 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 that 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 transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The 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. The adoption of this ASU is not expected to have a material impact on AltaGas' 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.

In May 2017, FASB issued ASU No. 2017-09 "Compensation – Stock Compensation: Scope of Modifications Accounting". The amendments in this ASU provide guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The 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. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In August 2017, FASB issued ASU No. 2017-12 "Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities". The amendments in this ASU improves the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and make certain targeted improvements to simplify the application of hedge accounting. The amendments in this ASU are effective for annual periods beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. 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 merger 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$6.7 billion, including the assumption of approximately US$2.2 billion of debt as at June 30, 2017.

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 236,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas expects that it will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

Consummation of the WGL Acquisition is subject to certain closing conditions, including 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 (HSR Act).

Regulatory applications were filed with the PSC of DC, the PSC of MD, and the SCC of VA on April 24, 2017. On the same date, AltaGas and WGL also filed their voluntary Joint Notice to the CFIUS, and an application with FERC. In addition, the staff to the SCC of VA has filed a productive report recommending approval of the proposed merger with conditions. That report and responses to the report are under consideration by the Virginia Commission, with a decision expected on or about October 20, 2017. In Maryland, the hearing before the PSC of MD concluded on October 16, 2017 and a decision is expected on or about December 5, 2017. The hearing before the PSC of DC is scheduled to begin on or about December 5, 2017 with a decision expected to follow in the first half of 2018. On May 10, 2017, WGL common shareholders voted in favor of the Merger Agreement. On July 6, 2017, the FERC found that the transaction is consistent with the public interest and is now approved. Also as of July 17, 2017 when the waiting period required by Section 7A(b)(1) of the HSR Act expired, the merger was deemed approved by the Federal Trade Commission and the Department of Justice, such approval being valid for one year. On July 28, 2017, CFIUS provided its approval for the merger.

The WGL Acquisition is expected to close in the first half of 2018. AltaGas plans to fund the WGL Acquisition with the proceeds from its aggregate $2.6 billion bought deal and private placement of subscription receipts, which closed in the first quarter of 2017 *(see Subscription Receipts section below)*. In addition, AltaGas has US$3 billion available under its fully committed bridge facility, which can be drawn at the time of closing. As progress is made towards meeting closing conditions, AltaGas is moving forward with its long-term financing plan for the WGL Acquisition, the proceeds of which may be used to reduce the bridge facility, which itself will remain available for 12 to 18 months following the close of the WGL Acquisition. AltaGas continues to pursue the first phase of its asset sale process, which includes Blythe and the Tracy facility in California and certain small non-core assets. Additional financing steps are expected to be undertaken in 2018, including additional asset sales, offerings of senior debt, hybrid securities, and equity-linked securities (including preferred shares), subject to prevailing market conditions.

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 WGL Acquisition 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		**September 30, 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" for the nine months ended September 30, 2017 related to this disposition.

5. INVENTORY

As at		**September 30, 2017**		December 31, 2016
Natural gas held in storage	**$**	**142.6**	$	172.6
Other inventory		**60.0**		48.4
	$	**202.6**	$	221.0

6. GOODWILL

As at		**September 30, 2017**		December 31, 2016
Balance, beginning of period	**$**	**856.0**	$	877.3
Foreign exchange translation		**(41.2)**		(17.9)
Reclassified to assets held for sale *(note 4)*		**—**		(3.4)
Balance, end of period	**$**	**814.8**	$	856.0

7. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at		**September 30, 2017**		December 31, 2016
Investments in publicly-traded entities	**$**	**90.1**	$	49.4
Loan to affiliate		**75.0**		62.5
Deferred lease receivable		**25.1**		16.3
Debt issuance costs associated with credit and bridge facilities		**22.6**		5.1
Refundable deposits		**14.9**		39.0
Loan to employee		**—**		0.8
Prepayment on long-term service agreements		**65.2**		8.7
Post-retirement benefit		**2.6**		2.8
Other		**9.5**		4.7
	$	**305.0**	$	189.3

At the end of May 2017, AltaGas concluded that it no longer exercised significant influence over Tidewater Midstream and Infrastructure Ltd. (Tidewater). Consequently, AltaGas ceased accounting for the investment under the equity method and reclassified the carrying value of the investment of approximately $65.4 million to "Long-term investments and other assets". The Tidewater common shares are now recorded at fair value. As a result of the loss of significant influence, AltaGas recorded an unrealized pre-tax loss of approximately $8.0 million in the Consolidated Statement of Income under the line item "Other income" in the second quarter of 2017. Subsequent changes in fair value are recognized in the Consolidated Statement of Income. For the three and nine months ended September 30, 2017, AltaGas recorded an unrealized pre-tax gain of $4.8 million and an unrealized pre-tax loss of $3.3 million, respectively related to the change in fair value of the investment in Tidewater.

8. VARIABLE INTEREST ENTITY

On May 5, 2017, AltaGas LPG Limited Partnership (AltaGas LPG), a wholly-owned subsidiary of AltaGas, and Vopak Development Canada Inc. (Vopak), a wholly-owned subsidiary of Koninklijke Vopak N.V. (Royal Vopak), a public company incorporated under the laws of the Netherlands, formed the Ridley Island LPG Export Limited Partnership (RILE LP) to develop, own and operate the Ridley Island Propane Export Terminal (RIPET). AltaGas' subsidiaries hold a 70 percent interest while Vopak holds a 30 percent interest in RILE LP. The construction cost of RIPET, which is estimated to be $450 to $500 million, will be funded by AltaGas LPG and Vopak in proportion to their respective interests in RILE LP. As part of the arrangements, AltaGas entered into a long-term agreement for the capacity of RIPET with RILE LP, and AltaGas and certain of its subsidiaries will provide construction and operating services to RILE LP.

AltaGas has determined that RILE LP is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through the construction, operating and marketing services provided to RILE LP. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to RILE LP through the long-term agreement for the capacity of RIPET. As such, AltaGas has consolidated RILE LP and recorded $20.0 million of the $24.1 million proceeds received from Vopak on formation of RILE LP as a non-controlling interest with the remainder of the proceeds less deferred tax recognized as contributed surplus in the amount of $3.0 million.

The following table represents amounts included in the consolidated balance sheets attributable to this VIE:

As at		September 30, 2017		December 31, 2016
Accounts receivable	**$**	**1.5**	$	—
Property, plant and equipment		**52.5**		—
Long-term investments and other assets		**48.0**		—
Net assets	**$**	**102.0**	$	—

The assets of RILE LP are the property of RILE LP and are not available to AltaGas for any other purpose. RILE LP's asset balances can only be used to settle its own obligations. The liabilities of RILE LP do not represent additional claims against AltaGas' general assets. AltaGas' exposure to loss as a result of its interest as a limited partner is its net investment. AltaGas and Royal Vopak have provided limited guarantees for the obligations of their respective subsidiaries for the construction cost of RIPET. Upon commencement of commercial operations at RIPET, the terms of the long-term capacity agreement between AltaGas LPG and RILE LP provide for a return on and of capital and reimbursement of RIPET operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

9. LONG-TERM DEBT

As at	Maturity date		September 30, 2017		December 31, 2016
Credit facilities					
$1,400 million unsecured extendible revolving[a]	15-Dec-2020	**$**	**665.4**	$	377.9
US$300 million unsecured extendible revolving[b]	8-Dec-2019		**12.5**		—
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		**—**		167.8
SEMCO long-term debt					
US$300 million SEMCO Senior secured - 5.15 percent[d]	21-Apr-2020		**374.4**		402.8
US$82 million CINGSA Senior secured - 4.48 percent[e]	2-Mar-2032		**84.8**		97.5
Debenture notes					
PNG RoyNat Debenture[f]	15-Sep-2017		**—**		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		**13.0**		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		**0.5**		0.6
CINGSA capital lease - 4.48 percent	4-Jun-2068		**0.2**		0.2
		$	**3,647.8**	$	3,764.7
Less debt issuance costs			**(12.0)**		(14.4)
			3,635.8		3,750.3
Less current portion			**(182.8)**		(383.4)
		$	**3,453.0**	$	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 carried 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 consisted 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.

10. 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		**(28.6)**		**—**		**6.8**		**(198.2)**		**(3.3)**		**(223.3)**
Amounts reclassified from AOCI		**—**		**0.7**		**—**		**—**		**—**		**0.7**
Settlement of PRB plan		**—**		**0.3**		**—**		**—**		**—**		**0.3**
Current period OCI (pre-tax)		**(28.6)**		**1.0**		**6.8**		**(198.2)**		**(3.3)**		**(222.3)**
Income tax on amounts retained in AOCI		**3.1**		**—**		**—**		**—**		**—**		**3.1**
Income tax on amounts reclassified to earnings		**—**		**(0.2)**		**—**		**—**		**—**		**(0.2)**
Income tax on amounts related to settlement of PRB plan		**—**		**(0.1)**		**—**		**—**		**—**		**(0.1)**
Net current period OCI		**(25.5)**		**0.7**		**6.8**		**(198.2)**		**(3.3)**		**(219.5)**
Ending balance, September 30, 2017	**$**	**(5.7)**	**$**	**(10.6)**	**$**	**(128.8)**	**$**	**328.1**	**$**	**2.6**	**$**	**185.6**
Opening balance, January 1, 2016	$	(2.4)	$	(9.6)	$	(169.6)	$	610.5	$	4.6	$	433.5
OCI before reclassification		22.1		—		54.7		(148.2)		0.5		(70.9)
Amounts reclassified from AOCI		—		0.7		—		—		—		0.7
Current period OCI (pre-tax)		22.1		0.7		54.7		(148.2)		0.5		(70.2)
Income tax on amounts retained in AOCI		(3.0)		—		(14.0)		—		—		(17.0)
Income tax on amounts reclassified to earnings		—		(0.2)		—		—		—		(0.2)
Net current period OCI		19.1		0.5		40.7		(148.2)		0.5		(87.4)
Ending balance, September 30, 2016	$	16.7	$	(9.1)	$	(128.9)	$	462.3	$	5.1	$	346.1

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item		**Three months ended September 30, 2017**		**Nine months ended September 30, 2017**
Defined benefit pension and PRB plans	Operating and administrative expense	**$**	**0.2**	$	**0.7**
Deferred income taxes	Income tax expenses – deferred		**(0.1)**		**(0.2)**
		$	**0.1**	$	**0.5**

AOCI components reclassified	Income statement line item		Three months ended September 30, 2016		Nine months ended September 30, 2016
Defined benefit pension and PRB plans	Operating and administrative expense	**$**	0.3	$	0.7
Deferred income taxes	Income tax expenses – deferred		(0.1)		(0.2)
		$	0.2	$	0.5

11. 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, Other current liabilities, 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 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.

	September 30, 2017				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Cash and cash equivalents	**$ 25.1**	**$ 25.1**	**$ —**	**$ —**	**$ 25.1**
Risk management assets - current	**32.8**	**—**	**32.8**	**—**	**32.8**
Risk management assets - non-current	**16.4**	**—**	**16.4**	**—**	**16.4**
Long-term investments and other assets [(a)]	**165.1**	**90.1**	**75.0**	**—**	**165.1**
	$ 239.4	**$ 115.2**	**$ 124.2**	**$ —**	**$ 239.4**
Financial liabilities					
Risk management liabilities - current	**$ 32.7**	**$ —**	**$ 32.7**	**$ —**	**$ 32.7**
Risk management liabilities - non-current	**12.0**	**—**	**12.0**	**—**	**12.0**
Current portion of long-term debt	**182.8**	**—**	**183.9**	**—**	**183.9**
Long-term debt	**3,453.0**	**—**	**3,516.4**	**—**	**3,516.4**
Other current liabilities [(b)]	**18.5**	**—**	**18.5**	**—**	**18.5**
Other long-term liabilities [(b)]	**140.4**	**—**	**138.3**	**—**	**138.3**
	$ 3,839.4	**$ —**	**$ 3,901.8**	**$ —**	**$ 3,901.8**

(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 September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Natural gas	**$ (1.9)**	$ (1.1)	**$ (3.9)**	$ (1.5)
Storage optimization	**—**	0.5	**2.8**	(3.4)
NGL frac spread	**(10.2)**	(1.0)	**(0.6)**	(3.4)
Power	**(3.0)**	5.1	**(12.1)**	8.1
Heat rate	**—**	—	**—**	(0.1)
Foreign exchange	**(10.2)**	—	**(32.7)**	0.9
Embedded derivative	**—**	—	**—**	0.2
	$ (25.3)	$ 3.5	**$ (46.5)**	$ 0.8

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 following is a summary of AltaGas' financial assets and financial liabilities that were subject to offsetting:

	September 30, 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	**$**	**27.2**	**$**	**(5.4)**	**$**	**21.8**
NGL frac spread		**1.7**		**(0.3)**		**1.4**
Power		**23.1**		**(0.9)**		**22.2**
Foreign exchange		**3.8**		**—**		**3.8**
	$	**55.8**	**$**	**(6.6)**	**$**	**49.2**
Risk management liabilities [(b)]						
Natural gas	**$**	**27.6**	**$**	**(5.4)**	**$**	**22.2**
NGL frac spread		**14.6**		**(0.3)**		**14.3**
Power		**9.1**		**(0.9)**		**8.2**
	$	**51.3**	**$**	**(6.6)**	**$**	**44.7**

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $32.8 million and risk management assets (non-current) balance of $16.4 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $32.7 million and risk management liabilities (non-current) balance of $12.0 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:

	September 30, 2017	December 31, 2016
Natural Gas		
Sales	**67,467,576 GJ**	63,209,420 GJ
Purchases	**56,432,695 GJ**	58,913,082 GJ
Swaps	**5,607,324 GJ**	474,037 GJ
NGL Frac Spread		
Propane swaps	**1,498,241 Bbl**	1,330,063 Bbl
Butane swaps	**12,236 Bbl**	49,500 Bbl
Crude oil swaps	**405,373 Bbl**	302,710 Bbl
Natural gas swaps	**8,591,739 GJ**	7,639,175 GJ
Power		
Sales	**2,352,110 MWh**	2,671,748 MWh
Purchases	**67,588 MWh**	217,520 MWh
Swaps	**1,607,237 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 September 30, 2017, AltaGas designated US$10.0 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$1.2 billion. These foreign currency option contracts do not qualify for hedge accounting.

12. 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).

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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 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	144,875		4.1
Deferred taxes on share issuance costs	—		0.1
Shares issued under DRIP	5,970,297		175.4
Issued and outstanding at September 30, 2017	**173,022,005**	**$**	**3,953.0**

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 September 30, 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 September 30, 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 September 30, 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 September 30, 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 September 30, 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 September 30, 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	—		(4.8)
Issued and outstanding at September 30, 2017	**12,000,000**	**$**	**295.2**

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 was paid on June 30, 2017 in the amount of $0.4384 per Series K preferred share. Unless otherwise redeemed or converted pursuant to the terms of the Series K preferred shares, 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.

On September 30, 2017, the annual fixed dividend rate for the cumulative redeemable five-year rate reset preferred shares, Series C, was reset to 5.29 percent. The dividend rate will reset on September 30, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.58 percent. No outstanding Series C preferred shares were converted into cumulative redeemable floating rate preferred shares, Series D on September 30, 2017 as less than 1,000,000 Series C preferred shares required to give effect to conversion into Series D preferred shares were tendered.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at September 30, 2017, 12,700,065 shares were reserved for issuance under the plan. As at September 30, 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 September 30, 2017, unexpensed fair value of share option compensation cost associated with future periods was $1.5 million (December 31, 2016 - $1.0 million).

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

As at	**September 30, 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	**737,500**	**31.02**	89,500	31.45
Exercised	**(144,875)**	**25.48**	(337,750)	25.28
Forfeited	**(109,875)**	**37.69**	(191,625)	35.60
Share options outstanding, end of period	**4,602,136**	**$ 32.27**	4,119,386	$ 32.39
Share options exercisable, end of period	**3,231,258**	**$ 31.02**	3,279,133	$ 30.56

(a) Weighted average.

As at September 30, 2017, the aggregate intrinsic value of the total options exercisable was $6.6 million (December 31, 2016 - $16.5 million), the total intrinsic value of options outstanding was $6.6 million (December 31, 2016 - $16.8 million) and the total intrinsic value of options exercised was $0.9 million (December 31, 2016 - $2.6 million).

The following table summarizes the employee share option plan as at September 30, 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	166,250	$ 15.17	1.53	166,250	$ 15.17	1.53
$18.01 to $25.08	549,725	21.26	2.71	549,725	21.26	2.71
$25.09 to $50.89	3,886,161	34.56	4.22	2,515,283	34.20	4.09
	4,602,136	**$ 32.27**	**3.94**	**3,231,258**	**$ 31.02**	**3.72**

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	**September 30, 2017**	December 31, 2016
(number of units)		
Balance, beginning of period	**364,839**	409,037
Granted	**283,364**	91,288
Vested and paid out	**(33,504)**	(136,359)
Forfeited	**(16,036)**	(13,565)
Units in lieu of dividends	**23,105**	14,438
Outstanding, end of period	**621,768**	364,839

For the three and nine months ended September 30, 2017, the compensation expense recorded for the MTIP and DSUP was $1.8 million and $5.0 million, respectively (2016 – $2.1 million and $5.5 million, respectively). As at September 30, 2017, the unrecognized compensation expense relating to the remaining vesting period was $9.0 million (December 31, 2016 - $12.4 million) and is expected to be recognized over the vesting period.

13. NET INCOME PER COMMON SHARE

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Numerator:				
Net income applicable to controlling interests	**$ 33.1**	$ 58.5	**$ 86.2**	$ 153.6
Less: Preferred share dividends	**(15.6)**	(12.1)	**(45.1)**	(36.0)
Net income applicable to common shares	**$ 17.5**	$ 46.4	**$ 41.1**	$ 117.6
Denominator:				
(millions)				
Weighted average number of common shares outstanding	**171.9**	164.1	**169.9**	154.2
Dilutive equity instruments[(a)]	**0.2**	0.5	**0.3**	0.4
Weighted average number of common shares outstanding - diluted	**172.1**	164.6	**170.2**	154.6
Basic net income per common share	**$ 0.10**	$ 0.28	**$ 0.24**	$ 0.76
Diluted net income per common share	**$ 0.10**	$ 0.28	**$ 0.24**	$ 0.76

(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 and nine months ended September 30, 2017, 3.8 million and 2.9 million share options, respectively (2016 – 1.6 million and 2.2 million, respectively) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

14. 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, Blythe entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines (CT) at Blythe over 116,000 equivalent operating hour per CT, or 20 years, whichever comes first. As at September 30, 2017, approximately $202.1 million is expected to be paid over the next 18 years, of which $55.3 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 $9.3 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.

15. 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 September 30, 2017					
	Canada		United States		Total	
	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits
Current service cost	**$ 2.0**	**$ 0.2**	**$ 1.7**	**$ 0.4**	**$ 3.7**	**$ 0.6**
Interest cost	**1.4**	**0.2**	**2.8**	**0.7**	**4.2**	**0.9**
Expected return on plan assets	**(1.5)**	**(0.1)**	**(3.9)**	**(1.1)**	**(5.4)**	**(1.2)**
Amortization of net actuarial loss	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Amortization of regulatory asset/liability	**0.3**	**—**	**1.6**	**(0.1)**	**1.9**	**(0.1)**
Net benefit cost recognized	**$ 2.4**	**$ 0.3**	**$ 2.2**	**$ (0.1)**	**$ 4.6**	**$ 0.2**

	Nine months ended September 30, 2017					
	Canada		United States		Total	
	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits
Current service cost	**$ 5.8**	**$ 0.5**	**$ 5.3**	**$ 1.2**	**$ 11.1**	**$ 1.7**
Interest cost	**4.3**	**0.5**	**8.7**	**2.2**	**13.0**	**2.7**
Expected return on plan assets	**(4.4)**	**(0.2)**	**(12.1)**	**(3.5)**	**(16.5)**	**(3.7)**
Settlement of plan	**—**	**—**	**—**	**(0.1)**	**—**	**(0.1)**
Amortization of past service cost	**0.1**	**—**	**—**	**—**	**0.1**	**—**
Amortization of net actuarial loss	**0.6**	**—**	**—**	**—**	**0.6**	**—**
Amortization of regulatory asset/liability	**0.9**	**0.1**	**4.9**	**(0.2)**	**5.8**	**(0.1)**
Net benefit cost recognized	**$ 7.3**	**$ 0.9**	**$ 6.8**	**$ (0.4)**	**$ 14.1**	**$ 0.5**

	Three months ended September 30, 2016					
	Canada		United States		Total	
	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits
Current service cost	$ 1.7	$ 0.2	$ 1.8	$ 0.5	$ 3.5	$ 0.7
Interest cost	1.4	0.2	2.9	0.9	4.3	1.1
Expected return on plan assets	(1.3)	(0.1)	(3.7)	(1.1)	(5.0)	(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	$ 0.3	$ 2.6	$ 0.5	$ 4.9	$ 0.8

	Nine months ended September 30, 2016					
	Canada		United States		Total	
	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits	Defined Benefits	Post-retirement Benefits
Current service cost	$ 5.3	$ 0.5	$ 5.4	$ 1.4	$ 10.7	$ 1.9
Interest cost	4.2	0.5	8.8	2.9	13.0	3.4
Expected return on plan assets	(4.0)	(0.1)	(11.3)	(3.4)	(15.3)	(3.5)
Cost / income special events	—	—	0.1	—	0.1	—
Amortization of past service cost	0.1	—	—	—	0.1	—
Amortization of net actuarial loss	0.6	—	—	—	0.6	—
Amortization of regulatory asset	0.9	—	4.8	0.6	5.7	0.6
Net benefit cost recognized	$ 7.1	$ 0.9	$ 7.8	$ 1.5	$ 14.9	$ 2.4

16. INCOME TAXES

The effective income tax rates for the three and nine months ended September 30, 2017 were approximately 28.2 percent and 31.6 percent, respectively (2016 – 22.1 percent and 14.5 percent, respectively). The increase in the effective tax rate for the three months ended September 30, 2017 was mainly due to unrecognized tax recoveries resulting from losses on certain risk management contracts and a portion of transaction costs incurred on the pending WGL Acquisition in the third quarter of 2017 not being tax deductible. The increase in the effective income tax rate for the nine months ended September 30, 2017 was further impacted by the tax recovery related to the sale of assets to Tidewater in the first quarter of 2016, and a portion of transaction costs incurred on the pending WGL Acquisition in the first half of 2017 not being tax deductible.

17. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Source (use) of cash:				
Accounts receivable	**$ (20.8)**	$ (36.4)	**$ 76.6**	$ 77.4
Inventory	**(51.7)**	(37.3)	**1.3**	(39.1)
Other current assets	**(1.0)**	(10.4)	**12.0**	(2.3)
Regulatory assets (current)	**(0.4)**	(1.0)	**(0.5)**	2.2
Accounts payable and accrued liabilities	**6.4**	19.1	**(22.9)**	(54.8)
Customer deposits	**11.4**	7.2	**(1.6)**	(2.7)
Regulatory liabilities (current)	**(1.5)**	(0.9)	**(9.8)**	2.9
Other current liabilities	**1.5**	2.9	**4.3**	0.6
Other operating assets and liabilities	**14.1**	(7.7)	**(44.0)**	(40.0)
Changes in operating assets and liabilities	**$ (42.0)**	$ (64.5)	**$ 15.4**	$ (55.8)

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Interest paid (net of capitalized interest)	**$ 33.2**	$ 46.7	**$ 121.4**	$ 116.8
Income taxes paid	**$ 6.0**	$ 6.7	**$ 29.5**	$ 29.7

18. 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.

19. 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 September 30, 2017					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Revenue	$ 205.4	$ 184.2	$ 152.4	$ 0.4	$ (15.6)	$ 526.8
Unrealized losses on risk management	—	—	(0.4)	(24.9)	—	(25.3)
Cost of sales	(121.1)	(60.1)	(62.4)	—	13.6	(230.0)
Operating and administrative	(38.6)	(20.5)	(53.1)	(15.5)	2.1	(125.6)
Accretion expenses	(1.0)	(1.7)	—	—	—	(2.7)
Depreciation and amortization	(17.1)	(28.9)	(20.1)	(2.9)	—	(69.0)
Income from equity investments	4.4	2.2	0.7	—	—	7.3
Other income (loss)	5.2	—	0.4	1.2	(0.1)	6.7
Foreign exchange gains	0.2	—	—	0.2	—	0.4
Interest expense	—	—	—	(39.5)	—	(39.5)
Income (loss) before income taxes	$ 37.4	$ 75.2	$ 17.5	$ (81.0)	$ —	$ 49.1
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 113.2	$ 1.2	$ 31.9	$ 0.4	$ —	$ 146.7
Intangible assets	$ 0.2	$ 11.1	$ 0.2	$ —	$ —	$ 11.5

(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.

	Nine months ended September 30, 2017					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Revenue	$ 741.4	$ 467.7	$ 773.9	$ 1.7	$ (126.8)	$ 1,857.9
Unrealized losses on risk management	—	—	(1.3)	(45.2)	—	(46.5)
Cost of sales	(476.2)	(173.9)	(405.9)	—	120.5	(935.5)
Operating and administrative	(125.2)	(67.4)	(165.3)	(70.9)	6.7	(422.1)
Accretion expenses	(3.0)	(5.2)	—	—	—	(8.2)
Depreciation and amortization	(50.3)	(90.5)	(61.8)	(8.5)	—	(211.1)
Provision on assets	—	(1.3)	—	—	—	(1.3)
Income from equity investments	17.1	5.4	1.9	—	—	24.4
Other income (loss)	(5.7)	0.8	3.6	4.0	(0.4)	2.3
Foreign exchange gains	0.2	—	—	1.6	—	1.8
Interest expense	—	—	—	(126.5)	—	(126.5)
Income (loss) before income taxes	$ 98.3	$ 135.6	$ 145.1	$ (243.8)	$ —	$ 135.2
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 180.1	$ 13.7	$ 78.8	$ 1.1	$ —	$ 273.7
Intangible assets	$ 1.2	$ 12.7	$ 1.3	$ 1.6	$ —	$ 16.8

(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.

	Three months ended September 30, 2016					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Revenue	$ 178.0	$ 168.5	$ 154.3	$ 3.2	$ (15.2)	$ 488.8
Unrealized gains on risk management	—	—	—	3.5	—	3.5
Cost of sales	(99.2)	(47.3)	(60.1)	—	10.6	(196.0)
Operating and administrative	(36.5)	(20.2)	(55.1)	(6.5)	4.7	(113.6)
Accretion expenses	(0.9)	(1.9)	—	—	—	(2.8)
Depreciation and amortization	(17.4)	(27.0)	(18.7)	(3.9)	—	(67.0)
Income (loss) from equity investments	(1.3)	2.4	0.5	—	—	1.6
Other income (loss)	0.5	(0.1)	0.4	1.7	(0.1)	2.4
Foreign exchange gains	—	—	—	0.1	—	0.1
Interest expense	—	—	—	(38.7)	—	(38.7)
Income (loss) before income taxes	$ 23.2	$ 74.4	$ 21.3	$ (40.6)	$ —	$ 78.3
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 31.0	23.2	24.6	0.8	—	$ 79.6
Intangible assets	$ 0.5	12.2	0.6	0.5	—	$ 13.8

(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.

	Nine months ended September 30, 2016					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Revenue	$ 563.5	$ 432.0	$ 724.4	$ 10.1	$ (202.4)	$ 1,527.6
Unrealized gains on risk management	—	—	—	0.8	—	0.8
Cost of sales	(338.2)	(136.0)	(362.6)	—	187.9	(648.9)
Operating and administrative	(118.1)	(71.9)	(171.4)	(31.8)	14.9	(378.3)
Accretion expenses	(2.9)	(5.4)	—	—	—	(8.3)
Depreciation and amortization	(47.4)	(80.9)	(61.7)	(11.7)	—	(201.7)
Income (loss) from equity investments	3.3	(8.5)	1.8	—	—	(3.4)
Other income (loss)	4.5	—	1.4	2.8	(0.4)	8.3
Foreign exchange gains	—	—	—	3.6	—	3.6
Interest expense	—	—	—	(111.2)	—	(111.2)
Income (loss) before income taxes	$ 64.7	$ 129.3	$ 131.9	$ (137.4)	$ —	$ 188.5
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 168.2	$ 44.4	$ 68.6	$ 3.2	$ —	$ 284.4
Intangible assets	$ 1.7	$ 14.2	$ 1.5	$ 2.6	$ —	$ 20.0

(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.

The following table shows goodwill and total assets by segment:

	Gas	Power	Utilities	Corporate	Total
As at September 30, 2017					
Goodwill	**$ 152.9**	**$ —**	**$ 661.9**	**$ —**	**$ 814.8**
Segmented assets	**$ 2,995.5**	**$ 3,372.8**	**$ 3,286.4**	**$ 277.3**	**$ 9,932.0**
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

20. SUBSEQUENT EVENTS

Subsequent events have been reviewed through October 18, 2017, the date on which these unaudited condensed interim Consolidated Financial Statements were issued.

On October 4, 2017, AltaGas issued an aggregate of $450.0 million of MTNs consisting of $200.0 million of MTNs with a coupon rate of 3.98 percent, maturing on October 4, 2027 and $250.0 million of MTNs with a coupon rate of 4.99 percent, maturing on October 4, 2047.

Supplementary Quarterly Operating Information

(unaudited)

	Q3-17	Q2-17	Q1-17	Q4-16	Q3-16
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	1,322	1,300	1,404	1,337	1,275
Extraction volumes (Bbls/d)(1)(2)	64,026	58,885	71,958	69,687	65,509
Frac spread - realized ($/Bbl)(1)(3)	14.96	9.06	10.56	6.11	6.29
Frac spread - average spot price ($/Bbl)(1)(4)	21.28	10.98	17.26	8.40	6.29
POWER					
Renewable power sold (GWh)	681	499	148	196	670
Conventional power sold (GWh)	992	409	385	374	587
Renewable capacity factor (%)	70.3	50.7	9.5	18.8	70.2
Contracted conventional availability factor (%)(5)	99.6	99.9	96.0	99.8	99.3
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	3.7	4.8	13.5	10.8	3.2
Natural gas deliveries - transportation (PJ)(6)	1.3	1.5	1.9	1.5	1.1
U.S. utilities					
Natural gas deliveries end use (Bcf)(6)	5.9	10.3	30.2	22.8	5.4
Natural gas deliveries transportation (Bcf)(6)	10.9	11.5	15.4	14.2	11.0
Service sites(7)	575,602	575,084	576,829	574,875	568,628
Degree day variance from normal - AUI (%)(8)	(16.9)	(7.4)	(2.2)	(0.6)	(8.4)
Degree day variance from normal - Heritage Gas (%)(8)	(20.4)	(4.3)	(1.9)	(1.0)	(7.4)
Degree day variance from normal - SEMCO Gas (%)(9)	5.7	(8.4)	(11.8)	(6.1)	(57.6)
Degree day variance from normal - ENSTAR (%)(9)	(16.6)	(5.4)	9.6	(1.4)	(36.1)

(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.

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