AltaGas

# NEWS RELEASE
# ALTAGAS LTD. REPORTS THIRD QUARTER RESULTS; SIGNS DEFINITIVE PROJECT AGREEMENT FOR CANADIAN WEST COAST PROPANE EXPORT SITE

**Calgary, Alberta (October 29, 2015)**

**Highlights**

- 28 percent increase in normalized FFO, 19 percent increase in FFO per share;
- 19 percent increase in normalized EBITDA;
- Signed definitive project agreement for a propane export site in British Columbia;
- Announced US$642 million acquisition of 523 MW U.S. natural gas-fired generation facilities;
- Safely commissioned McLymont Creek Hydroelectric Facility; and
- Increased common share dividend by $0.005 per share to $1.98 per share annually; 12 percent overall increase in 2015.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported third quarter normalized EBITDA of $125 million, compared to $105 million in third quarter 2014. Normalized funds from operations were $102 million ($0.75 per share) for the third quarter 2015 compared to $80 million ($0.63 per share) in third quarter 2014. AltaGas continues to deliver strong results and growth driven by its diversified energy infrastructure across North America.

"We have made significant strides in delivering on our strategic plan with the completion of the Northwest hydroelectric facilities, progress in gas infrastructure to support exports, growing our gas-fired power generation in the U.S. and steady growth in our utilities," said David Cornhill, Chairman and CEO of AltaGas. "These steps will create growth and long-term shareholder value for years to come."

AltaGas continues to progress on its integrated northeast British Columbia strategy on several different fronts. Construction is well under way at the new 198 Mmcf/d Townsend shallow-cut processing facility, which will be underpinned by take-or-pay commitments from Painted Pony Petroleum Ltd. The Townsend facility is on track to be in service by mid-2016. Development of a liquids separation and handling facility near Fort St. John, which will provide value-added services for producers in the Montney region, continues to progress. AltaGas expects to receive permits and to reach a final investment decision by mid-2016.

On energy exports, AltaGas has entered into a definitive project agreement for the development of a propane export facility in British Columbia. AltaGas is negotiating other formal agreements and working to progress consultations with First Nations and stakeholders and to commence the regulatory and permitting process for the propane export facility. Preliminary engineering has been completed and a front end engineering and design study will be initiated shortly. This export facility is expected to initially ship up to 1.2 million tonnes per annum. AltaGas will move toward a final investment decision on the propane export facility once consultations with First Nations and stakeholders and regulatory approvals are complete.

AltaGas continues to progress on the permitting process, project design and execution plans on its DC LNG project. AltaGas was notified by Canada Border Services Agency (CBSA) of a 25 percent customs import duty that would apply to the floating LNG facility. AltaGas has filed an appeal with CBSA.

AltaGas also continues to drive its strategy for highly contracted, clean power generation. On September 21, 2015, AltaGas announced that it and its indirect wholly owned subsidiary AltaGas Power Holdings (U.S.) Inc. entered into a purchase and sale agreement to acquire an aggregate of 523 megawatts (MW) of natural gas-fired generation, comprising the Tracy, Hanford and Henrietta facilities located in northern California, for US$642 million, (the Acquisition). The Acquisition is expected to drive incremental EBITDA of approximately CAD$95 million per year in the first full year of ownership. The facilities are fully contracted under Power Purchase Agreements through the fourth quarter of 2022. The Acquisition is expected to close late in the fourth quarter 2015.

On October 1, 2015 AltaGas announced the successful start-up of its 66 MW McLymont Creek Hydroelectric Facility and on October 25 had successfully completed all the requirements under the Electricity Purchase Agreement with BC Hydro to achieve commercial operations. Commercial operations of the McLymont Creek Hydroelectric Facility represents the final phase of the $1 billion Northwest hydro projects, including the construction of Forrest Kerr and Volcano Creek hydroelectric facilities, which were commissioned in the second half of 2014. All three facilities are fully contracted under 60-year, fully indexed Electricity Purchase Agreements with BC Hydro.

In third quarter 2015, normalized EBITDA was driven by full quarter contributions from Forrest Kerr and Volcano Creek hydroelectric facilities, new U.S. natural gas-fired power assets acquired in January 2015, favourable foreign exchange rates, higher Utility earnings driven by rate base and customer growth across all Utilities and the early approval of SEMCO Gas' Main Replacement Program. These increases were partially offset by lower commodity prices and extraction volumes, reduced earnings from Petrogas Energy Corp. (Petrogas) and third party pipeline curtailments downstream of certain AltaGas processing facilities.

Normalized funds from operations increased, driven by the previously discussed increase in EBITDA, partially offset by higher interest costs as a result of new assets being placed into service and current income tax expense.

Normalized net income was $19 million ($0.14 per share), compared to $17 million ($0.13 per share) in third quarter 2014.

On a GAAP basis, AltaGas reported net income applicable to common shares of $20 million ($0.15 per share) in third quarter 2015, compared to net income of $17 million ($0.13 per share) for the same period 2014.

For the nine months ended September 30, 2015, normalized EBITDA was $409 million compared to $392 million for the same period in 2014. The increase was primarily due to earnings from Forrest Kerr, Volcano Creek and the U.S. natural gas-fired power assets, improved results for Energy Services, the stronger US dollar, higher Utility earnings driven by rate base and customer growth across all Utilities and the early approval of SEMCO Gas' Main Replacement Program. These increases were partially offset by the impact of lower contributions from Alberta power assets and sales of NGL, the turnarounds at Younger and Harmattan in the second quarter 2015, reduced earnings from Petrogas, lower throughput at certain processing facilities and pipeline curtailments downstream of certain AltaGas processing facilities.

Normalized funds from operations for the first nine months ended September 30, 2015 was $311 million ($2.30 per share), compared to $318 million ($2.56 per share) for same period 2014. Funds from operations decreased primarily due to the discretionary timing of dividend payments from Petrogas. A dividend of $28 million was received from Petrogas in second quarter 2014 compared to nil year-to-date 2015. Cash was retained at Petrogas in order to fund its projects, which will serve to enhance its North American liquids storage and logistics capabilities.

Normalized net income for nine months ended September 30, 2015, was $84 million ($0.62 per share), compared to $117 million ($0.94 per share) for the same period 2014. On a GAAP basis, net income applicable to common shares was $64 million ($0.48 per share) for the nine months ended September 30, 2015, compared to $85 million ($0.69 per share) for the same period 2014. Net income applicable to common shares for the nine months ended September 30, 2015 was normalized for unrealized gains and losses on risk management contracts and long-term investments, provisions on long-lived assets, transaction costs related to acquisitions, development costs incurred for the energy export projects and statutory tax rate changes. In 2014, net income applicable to common shares was normalized for unrealized losses on risk management contracts, provisions on long-lived assets, costs associated with early redemption of medium-term notes (MTNs) and gains on asset dispositions.

**Monthly Common Share Dividend and Quarterly Preferred Share Dividend**

- The Board of Directors approved the November 2015 dividend of $0.165 per common share. The dividend will be paid on December 15, 2015, to common shareholders of record on November 25, 2015. The ex-dividend date is November 23, 2015. This dividend is eligible for Canadian income tax purposes.
- The Board of Directors approved a dividend of $0.21125 per share for the period commencing October 1, 2015 and ending December 31, 2015, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on December 31, 2015 to shareholders of record on December 15, 2015. The ex-dividend date is December 11, 2015;
- The Board of Directors approved a dividend of $0.19156 per share for the period commencing October 1, 2015 and ending December 31, 2015, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on December 31, 2015 to shareholders of record on December 15, 2015. The ex-dividend date is December 11, 2015;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing October 1, 2015 and ending December 31, 2015, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on December 31, 2015 to shareholders of record on December 15, 2015. The ex-dividend date is December 11, 2015;
- The Board of Directors also approved a dividend of $0.3125 per share for the period commencing October 1, 2015, and ending December 31, 2015, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on December 31, 2015 to shareholders of record on December 15, 2015. The ex-dividend date is December 11, 2015; and
- The Board of Directors also approved a dividend of $0.296875 per share for the period commencing October 1, 2015, and ending December 31, 2015, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on December 31, 2015 to shareholders of record on December 15, 2015. The ex-dividend date is December 11, 2015.

**CONSOLIDATED FINANCIAL REVIEW**

| (unaudited) ($ millions) | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Revenue | **452** | 444 | **1,613** | 1,739 |
| Net revenue[1] | **268** | 217 | **781** | 734 |
| Normalized operating income[1] | **69** | 59 | **248** | 261 |
| Normalized EBITDA[1] | **125** | 105 | **409** | 392 |
| Net income applicable to common shares | **20** | 17 | **64** | 85 |
| Normalized net income[1] | **19** | 17 | **84** | 117 |
| Total assets | **8,959** | 8,125 | **8,959** | 8,125 |
| Total long-term liabilities | **4,208** | 3,973 | **4,208** | 3,973 |
| Net additions to property, plant and equipment | **164** | 136 | **417** | 359 |
| Dividends declared[2] | **65** | 56 | **188** | 155 |
| Cash flows | | | | |
| Normalized funds from operations[1] | **102** | 80 | **311** | 318 |

| ($ per share, except shares outstanding) | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Normalized EBITDA[1] | **0.92** | 0.83 | **3.03** | 3.15 |
| Net income per common share - basic | **0.15** | 0.13 | **0.48** | 0.69 |
| Net income per common share - diluted | **0.14** | 0.13 | **0.47** | 0.68 |
| Normalized net income[1] | **0.14** | 0.13 | **0.62** | 0.94 |
| Dividends declared[2] | **0.48** | 0.44 | **1.39** | 1.25 |
| Cash flows | | | | |
| Normalized funds from operations[1] | **0.75** | 0.63 | **2.30** | 2.56 |
| Shares outstanding - basic (millions) | | | | |
| During the period[3] | **136** | 127 | **135** | 124 |
| End of period | **145** | 133 | **145** | 133 |

*(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 $0.1475 beginning on May 26, 2014 and $0.16 beginning on May 25, 2015.*

*(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 third quarter financial results, progress on construction projects and other corporate developments.

Members of the media, investment communities and other interested parties may dial (416) 340-2218 or call toll free at 1-866-225-2055. There is no passcode. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_events. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905) 694-9451 or 1-800-408-3053. The passcode is 1022285. The replay expires at midnight (Eastern) on November 5, 2015.

AltaGas is an energy infrastructure business 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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*This news release contains forward-looking statements. When used in this news release, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or an affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, the anticipated benefits of the Acquisition and other major projects, the timing of commercial operations dates, investment decisions, expenditures, permitting and closing of acquisitions and dispositions, expected growth, results of operations, performance, business projects and opportunities and financial results. 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 or regulatory developments, general economic conditions and other factors set out in AltaGas' public disclosure documents. 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.*

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*The Management's Discussion and Analysis (MD&A) of operations and unaudited condensed interim Consolidated Financial Statements presented herein are 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, 2015. This MD&A dated October 29, 2015, 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, 2015, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2014.*

*The unaudited condensed interim 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.*

*This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or any affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, the anticipated benefits of the GWF acquisition and other major projects, the timing of commercial operation dates, investment decisions, expenditures, permitting and closing of acquisitions and dispositions, expected growth, capital expenditures, results of operations, operational and financial performance, business projects, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "2015 Outlook" and "Growth Capital".*

*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 or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in AltaGas' public disclosure documents.*

*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 or expected, and such forward looking statements included in this MD&A herein 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 as cautionary statements.*

*Financial outlook information contained in this MD&A about prospective results of operations, 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 the purposes other than for which it is disclosed herein.*

*Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Management Information Circular, material change reports and press releases, are also available through AltaGas' website or through SEDAR at www.sedar.com.*

## ALTAGAS ORGANIZATION

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., AltaGas Services (U.S.) Inc., and Coast Mountain Hydro Limited Partnership.

## THIRD QUARTER HIGHLIGHTS (1)

- Normalized funds from operations were $102 million, 28 percent increase compared to $80 million in third quarter 2014;
- Normalized EBITDA was $125 million, 19 percent increase compared to $105 million in third quarter 2014;
- Net revenue was $268 million, compared to $217 million in third quarter 2014;
- Net debt was $3.0 billion as at September 30, 2015, compared to $2.8 billion as at September 30, 2014, and $2.9 billion as at December 31, 2014;
- Debt-to-total capitalization ratio was 42 percent as at September 30, 2015, compared to 44 percent as at September 30, 2014, and 45 percent as at December 31, 2014;
- On September 21, 2015, AltaGas entered into a purchase and sale agreement to acquire GWF Energy Holdings LLC (GWF), which holds a portfolio of three natural gas-fired electrical generation facilities in California totaling 523 MW, for US$642 million prior to customary closing adjustments;
- On September 21, 2015, AltaGas announced an increase in its dividend by $0.005 per common share per month to $0.165 ($1.98 per common share annualized) effective for the October dividend payable in November; and
- On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

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

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| Net additions to property, plant and equipment | **164** | 136 | **417** | 359 |
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| Normalized net income[(1)] | **0.14** | 0.13 | **0.62** | 0.94 |
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*(3) Weighted average.*

**Three Months Ended September 30**

Overall results for third quarter 2015 reflect the normal seasonality of the businesses including the seasonally stronger quarter from the hydro assets offset by lower results from the natural gas utilities during the summer months. Forrest Kerr and Volcano Creek outperformed design parameters in third quarter 2015; however, below average seasonal rainfall combined with a smaller snowpack this year impacted river flows at Forrest Kerr in third quarter 2015. In addition, third quarter results continue to be impacted by the low commodity price environment when compared to third quarter 2014.

Normalized EBITDA for third quarter 2015 was $125 million, compared to $105 million for same quarter 2014. Full quarter contributions from Forrest Kerr, Volcano Creek and the U.S. natural gas-fired power assets that were acquired in January 2015 contributed normalized EBITDA growth of approximately $34 million. The stronger US dollar on reported results of the U.S. assets also contributed to the increase in normalized EBITDA. These increases were partially offset by record low power prices in Alberta, lower spot frac spreads, lower extraction volumes, lower earnings from Petrogas Energy Corp. (Petrogas) and the impact of third party pipeline curtailments downstream of certain AltaGas processing facilities.

Normalized funds from operations for third quarter 2015 were $102 million ($0.75 per share), compared to $80 million ($0.63 per share) for same quarter 2014. The increase in normalized funds from operations was driven by the same drivers as normalized EBITDA, partially offset by higher interest costs and current income tax expense.

Normalized operating income for third quarter 2015 was $69 million, compared to $59 million for same quarter 2014, which reflects the factors noted above for normalized EBITDA partially offset by higher depreciation and amortization expense due to new assets placed into service.

Operating and administrative expense for third quarter 2015 was $134 million, compared to $113 million for same quarter 2014. The increase was primarily due to higher operating and administrative costs incurred by the Power segment due to new assets placed into service and the impact of the stronger US dollar. Depreciation and amortization expense for third quarter 2015 was $53 million, compared to $44 million for same quarter 2014, due to the new assets placed into service.

Interest expense for third quarter 2015 was $31 million, compared to $29 million for same quarter 2014. Interest expense increased due to lower capitalized interest, primarily due to Forrest Kerr and Volcano Creek entering service in 2014, and higher interest costs on US dollar denominated debt due to the weaker Canadian dollar.

AltaGas recorded income tax expense of $5 million for third quarter 2015, compared to $2 million in same quarter 2014. The increase is due to higher tax expenses related to unrealized gains on risk management contracts.

Normalized net income was $19 million ($0.14 per share) for third quarter 2015, compared to $17 million ($0.13 per share) reported for same quarter 2014. The increase in normalized net income of $2 million was primarily due to the increase in normalized operating income as discussed above partially offset by higher interest and income tax expense.

Net income applicable to common shares for third quarter 2015 was $20 million ($0.15 per share), compared to $17 million ($0.13 per share) for same quarter 2014. Net income applicable to common shares for third quarter 2015 was normalized for after-tax amounts related to provisions on certain long-lived assets, development costs related to energy exports projects, and unrealized gains and losses on risk management contracts. In third quarter 2014, net income applicable to common shares was normalized for unrealized gains on risk management contracts and development costs related to energy export projects.

**Nine Months Ended September 30**

Normalized EBITDA for nine months ended September 30, 2015 was $409 million, compared to $392 million for same period 2014. Earnings from Forrest Kerr, Volcano Creek and the new U.S. natural gas-fired power assets, improved results for Energy Services and the stronger US dollar contributed to higher normalized EBITDA. These increases were partially offset by the impact of lower contributions from Alberta power assets and sales of natural gas liquids (NGL), the impact of the major turnarounds at Younger and Harmattan in second quarter 2015, lower earnings from Petrogas, lower throughput at certain processing facilities and the impact of pipeline curtailments downstream of certain AltaGas processing facilities.

Normalized funds from operations for nine months ended September 30, 2015 were $311 million ($2.30 per share), compared to $318 million ($2.56 per share) for same period 2014. The decrease was primarily due to the discretionary timing of dividend payments from Petrogas. A dividend of $28 million (AltaGas' share) was declared by Petrogas in the first half of 2014 whereas no dividend was declared during the first nine months of 2015 as cash was retained by Petrogas to fund its capital program. Adjusting for the Petrogas dividend received, normalized funds from operations were $290 million for the nine months ended September 30, 2014. The remaining change in normalized funds from operations reflects the same drivers as normalized EBITDA, partially offset by higher interest costs and current income tax expense.

Normalized operating income for nine months ended September 30, 2015 was $248 million, compared to $261 million for same period 2014, driven by the same factors as normalized EBITDA offset by higher depreciation and amortization expense.

Operating and administrative expense for nine months ended September 30, 2015 was $372 million, compared to $336 million for same period 2014. The increase was primarily due to the non-capitalizable turnaround costs at Younger and Harmattan, new assets placed into service and the impact of the stronger US dollar. Depreciation and amortization expense for nine months ended September 30, 2015 increased to $153 million compared to $127 million for same period 2014 mainly due to new assets placed into service.

Interest expense for nine months ended September 30, 2015 was $92 million, compared to $77 million for same period 2014. Interest expense increased primarily due to interest no longer being capitalized on assets placed into service in second half 2014 and higher interest costs incurred on the US dollar denominated debt.

AltaGas recorded income tax expense of $45 million for nine months ended September 30, 2015 compared to $25 million for the same period 2014. Income tax expense increased primarily due to higher future income taxes as a result of a 2 percent increase in the Alberta corporate income tax rate that was enacted on June 29, 2015 and higher taxable income.

Normalized net income for nine months ended September 30, 2015 was $84 million ($0.62 per share), compared with $117 million ($0.94 per share) reported for same period 2014. The decrease was primarily due to the lower normalized operating income as discussed above along with higher interest and income tax expense and preferred share dividends.

Net income applicable to common shares for nine months ended September 30, 2015 was $64 million ($0.48 per share) compared to $85 million ($0.69 per share) for same period 2014. Net income applicable to common shares for year-to-date 2015 was normalized for unrealized gains and losses on risk management contracts and long-term investments, provisions on certain long-lived assets, development costs incurred for the energy export projects and statutory tax rate changes. In 2014, net income applicable to common shares was normalized for unrealized losses on risk management contracts, provisions on certain long-lived assets, costs associated with early redemption of medium-term notes (MTNs), development costs incurred for energy export projects and gain on asset dispositions.

**2015 OUTLOOK**

AltaGas currently expects to deliver overall normalized EBITDA growth of approximately 10 percent in 2015 compared to 2014. Growth in 2015 normalized EBITDA is expected to be at the lower end of previous estimates due to continued weak NGL and Alberta power prices, the delay in the commissioning of the McLymont Creek run-of-river hydro facility, lower average third quarter water flows at Forrest Kerr and continued third party downstream pipeline curtailments. However, the GWF acquisition is expected to contribute approximately $8 million to 2015 normalized EBITDA assuming that the acquisition closes on November 30, 2015.

The Power and Utilities segments are expected to report higher normalized operating income, partially offset by lower normalized operating income from the Gas segment as compared to 2014.

AltaGas expects normalized funds from operations to be roughly flat to 2014 as a result of lower dividends from Petrogas, higher interest costs, and higher current income taxes at the utilities.

For the remainder of 2015, AltaGas has hedged approximately 41 percent of expected volumes exposed to Alberta power prices at an average price of approximately $48/MWh. In the gas segment, management estimates an average of 6,400 Bbls/d will be exposed to frac spread in the remainder of 2015. AltaGas has hedged approximately 3,000 Bbls/d for the remainder of 2015 at an average price of approximately $27/Bbl before deducting extraction premiums. Given weak commodity prices, AltaGas does not expect to enter into frac hedges for 2016 at this time.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong fourth quarter due to the winter heating season. The utilities are expected to report increased earnings in 2015 driven by customer and rate base growth. SEMCO Energy Gas Company (SEMCO Gas), the Michigan division of SEMCO Energy, Inc. (SEMCO) expects approximately US$3 million of additional earnings in 2015 as a result of the approval of its Main Replacement Program. In addition, ENSTAR Natural Gas Company (ENSTAR), the Alaska division of SEMCO filed a stipulation to resolve all matters with rate case interveners in its rate case in August. The stipulation included a rate increase (annualized) of approximately US$4 million effective October 1, 2015 as well as an additional interim and refundable rate increase (annualized) of approximately US$2 million effective January 1, 2016. The stipulation was accepted by the Regulatory Commission of Alaska in an order dated September 29, 2015. ENSTAR also agreed to a 2016 rate case with a 2015 test year. Earnings at all of the utilities except Pacific Northern Gas Ltd. (PNG) are affected by the weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normalized weather, earnings at the utilities would be affected.

If the US dollar remains strong compared with 2014, the operating income reported for the U.S. assets will benefit accordingly in 2015. Some of this benefit is offset by interest on US dollar denominated debt, dividends on US dollar denominated preferred shares and U.S. income tax expense.

On June 29, 2015, the Government of Alberta enacted a bill to increase the provincial corporate tax rate from 10 percent to 12 percent with an effective date of July 1, 2015. There is no expected impact on AltaGas’ cash income taxes and funds from operations in 2015 as a result of the increase in Alberta corporate tax rate.

## GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $600 million to $700 million for 2015, excluding the GWF acquisition. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through internally-generated cash flow, the Dividend Reinvestment and Optional Share Purchase Plan (DRIP), and available credit facilities. As at September 30, 2015, the Corporation had approximately $1.7 billion available on its credit facilities as well as cash on hand of $410 million and debt-to-total capitalization of 42 percent.

### McLymont Creek Hydroelectric Facility

On October 1, 2015, AltaGas started producing power at its 66-MW McLymont Creek hydroelectric facility. Commissioning activities continued throughout October and on October 25, 2015, AltaGas successfully completed all the requirements under the Electricity Purchase Agreement with BC Hydro to achieve commercial operations.

### Townsend Gas Processing Facility

The Townsend Facility is a 198 Mmcf/d shallow cut gas processing facility located approximately 100 kilometers north of Fort St. John and 20 kilometers southeast of AltaGas' Blair Creek Facility. Painted Pony Petroleum Ltd. (Painted Pony) has reserved all of the firm capacity under a 20 year take-or-pay agreement. The estimated cost for the facility and associated infrastructure is

$325 to $350 million. AltaGas has begun construction and approximately $200 million of equipment and services have been procured for the project to date. Earth works are 95 percent complete, piping prefabrication is 30 percent complete, some major equipment modules have started to arrive at site, and the facility is on track to be in service by mid-2016.

Incremental to the Townsend Facility are two other projects. The first is a 25km gas gathering line, estimated to cost $40 to $45 million which will connect the Blair Creek field gathering area to the Townsend Facility. Painted Pony has reserved all of the firm service under a 20 year take-or-pay agreement. AltaGas has moved into the construction phase on this project and it is on track to be completed in mid-2016. The second project consists of two liquids egress lines, approximately 30km, and a truck terminal on the Alaska Highway. The lines will connect the Townsend Facility to the truck terminal and have a combined initial capacity of 60,000 bbls/day. This project is in advanced stages of engineering and upon execution of take-or-pay agreements, expected by the end of 2015, it will move into construction.

**Harmattan Cogeneration III**

Cogeneration III is on budget with a total project cost of approximately $40 million. Final tie-in of the steam system was completed during the Harmattan turnaround in May and with the commissioning of the hot oil heat recovery system completed during third quarter 2015, Cogeneration III was declared in service on October 1, 2015.

**Northeast British Columbia Liquids Separation Facility**

AltaGas has begun development of a liquids separation and handling facility near Fort St. John which will serve producers in the Montney region. The site is well connected by rail to Canada's west coast and North American markets. A front end engineering and design (FEED) study is in progress and is expected to be completed by the end of 2015. Consultations with key stakeholders continued in third quarter 2015 and AltaGas expects to receive permits to reach a financial investment decision by mid-2016.

**GWF Acquisition**

On September 21, 2015, AltaGas and its indirect wholly-owned subsidiary AltaGas Power Holdings (U.S.) Inc., entered into a purchase and sale agreement to acquire GWF, which holds a portfolio of three natural gas-fired electrical generation facilities in northern California totaling 523 MW, for US$642 million, excluding customary closing adjustments. The transaction is expected to close in fourth quarter 2015.

The transaction is subject to customary approvals, including Federal Energy Regulatory Commission approval pursuant to Federal Power Act section 203, and expiration or termination of the applicable waiting periods under the Hart Scott Rodino Antitrust Improvements Act of 1976 (HSR). Early termination of the HSR review period was granted on October 14, 2015.

**Douglas Channel Liquefied Natural Gas (DC LNG) Project**

AltaGas continues to progress on the permitting process, project design and execution plans on its DC LNG project. AltaGas was notified by Canada Border Services Agency (CBSA) of a 25 percent customs import duty that would apply to the floating liquefied natural gas facility. AltaGas has filed an appeal with CBSA.

**Propane Export Facility**

AltaGas has entered into a definitive project agreement for the development of a propane export facility in British Columbia. AltaGas is negotiating other formal agreements and working to progress consultations with First Nations and stakeholders and to commence the regulatory and permitting process for the propane export facility. Preliminary engineering has been completed and a FEED study will be initiated shortly. This export facility is expected to initially ship up to 1.2 million tonnes per annum. AltaGas will move toward a final investment decision on the propane export facility once consultations with First Nations and stakeholders and regulatory approvals are complete.

## NON-GAAP FINANCIAL MEASURES

This MD&A 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 below. These 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 below.

References to net revenue, normalized operating income, normalized EBITDA, normalized net income and normalized funds from operations throughout this document have the meanings as set out in this section.

**Net Revenue**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Net revenue | **$ 268** | $ 217 | **$ 781** | $ 734 |
| Add (deduct): | | | | |
| Other income | **(1)** | (1) | **(5)** | (13) |
| Loss (income) from equity investments | **5** | (13) | **5** | (38) |
| Cost of sales | **180** | 241 | **832** | 1,056 |
| Revenue (GAAP financial measure) | **$ 452** | $ 444 | **$ 1,613** | $ 1,739 |

Management believes that net revenue, which is revenue adjusted for other income, income from equity investments that are not classified as held-for-trading, and the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of commodities affect both revenue and cost of sales, and equity investments are part of operating activities for the Corporation.

**Normalized Operating Income**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Normalized operating income | **$ 69** | $ 59 | **$ 248** | $ 261 |
| Add (deduct): | | | | |
| Transaction costs related to acquisitions | — | — | — | — |
| Unrealized gain on long-term investments | **—** | — | **1** | — |
| Provision on long-lived assets | **(11)** | — | **(11)** | (49) |
| Costs associated with early redemption of MTNs | **—** | — | **—** | (2) |
| Gain on asset dispositions | **—** | — | **—** | 11 |
| Joint venture development costs | **(1)** | (1) | **(2)** | (1) |
| Unrealized gain (loss) on risk management contracts | **11** | 1 | **2** | (2) |
| Interest expense | **(31)** | (29) | **(92)** | (77) |
| Foreign exchange loss | **—** | — | **—** | — |
| Income tax expense | **(5)** | (2) | **(45)** | (25) |
| Net income after taxes (GAAP financial measure) | **$ 32** | $ 28 | **$ 101** | $ 116 |

Normalized operating income is calculated from the Consolidated Statements of Income using net income adjusted for pre-tax unrealized gain or loss on risk management contracts, interest expense, foreign exchange gain (loss), income tax expense, transaction costs related to acquisitions, realized/unrealized gain (loss) on long-term investments, provision taken on long-lived assets, costs associated with early redemption of MTNs, and gain (loss) on asset dispositions. Normalized operating income also includes an adjustment for the project development costs incurred by AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP). Management believes that adjusting net income for these non-operating items is a better indicator of operating performance than net income as it is more comparable between periods.

**Normalized EBITDA**

| ($ millions) | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Normalized EBITDA | **$ 125** | $ 105 | **$ 409** | $ 392 |
| Add (deduct): | | | | |
| Transaction costs related to acquisitions | **—** | — | **—** | — |
| Unrealized gain on long-term investments | **—** | — | **1** | — |
| Gain on asset dispositions | **—** | — | **—** | 11 |
| Joint venture development costs | **(1)** | (1) | **(2)** | (1) |
| Unrealized gain (loss) on risk management contracts | **11** | 1 | **2** | (2) |
| Accretion expenses | **(3)** | (2) | **(8)** | (4) |
| Provision on long-lived assets | **(11)** | — | **(11)** | (49) |
| Costs associated with early redemption of MTNs | **—** | — | **—** | (2) |
| Foreign exchange loss | **—** | — | **—** | — |
| EBITDA(1) | **$ 121** | $ 103 | **$ 391** | $ 345 |
| Add (deduct): | | | | |
| Depreciation and amortization | **(53)** | (44) | **(153)** | (127) |
| Interest expense | **(31)** | (29) | **(92)** | (77) |
| Income tax expense | **(5)** | (2) | **(45)** | (25) |
| Net income after taxes (GAAP financial measure) | **$ 32** | $ 28 | **$ 101** | $ 116 |

*(1) AltaGas revised the calculation of EBITDA to earnings before interest, taxes, depreciation and amortization effective July 1, 2015. Comparative information has been restated to reflect this change. Calculation of normalized EBITDA remains unchanged.*

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 Statements 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 gain (loss) on risk management contracts, realized/unrealized gain (loss) on long-term investments, transaction costs related to acquisitions, gain (loss) on asset dispositions, accretion expense, provision on long-lived assets, costs associated with early redemption of MTNs and foreign exchange gain (loss). Normalized EBITDA also includes an adjustment for the project development costs incurred by AIJVLP. AltaGas presents normalized EBITDA as a supplemental measure as it is frequently used by analysts and investors in the evaluation of companies within the industry.

**Normalized Net Income**

| ($ millions) | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Normalized net income | **$ 19** | $ 17 | **$ 84** | $ 117 |
| Add (deduct) after-tax: | | | | |
| Transaction costs related to acquisitions | **—** | — | **—** | — |
| Unrealized gain (loss) on risk management contracts | **8** | 1 | **1** | (1) |
| Unrealized gain on long-term investments | **—** | — | **1** | — |
| Gain on asset dispositions | **—** | — | **—** | 9 |
| Provision on long-lived assets | **(6)** | — | **(6)** | (37) |
| Joint venture development costs | **(1)** | (1) | **(2)** | (1) |
| Costs associated with early redemption of MTNs | **—** | — | **—** | (2) |
| Statutory tax rate change | **—** | — | **(14)** | — |
| Net income applicable to common shares (GAAP financial measure) | **$ 20** | $ 17 | **$ 64** | $ 85 |

Normalized net income represents net income applicable to common shares adjusted for after-tax impact of all mark-to-market accounting gains (losses), gain (loss) on asset dispositions, provision taken on long-lived assets, transaction costs related to acquisitions, costs associated with early redemption of MTNs and statutory tax rate changes. Normalized net income also includes an adjustment for the project development costs incurred by AIJVLP. 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**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Normalized funds from operations | **$ 102** | $ 80 | **$ 311** | $ 318 |
| Add (deduct): | | | | |
| Transaction costs related to acquisitions | **—** | — | **—** | — |
| Funds from operations | **102** | 80 | **311** | 318 |
| Add (deduct): | | | | |
| Net change in operating assets and liabilities | **(42)** | (7) | **101** | 42 |
| Asset retirement obligations settled | **—** | — | **(2)** | (1) |
| Cash from operations (GAAP financial measure) | **$ 60** | $ 73 | **$ 410** | $ 359 |

Normalized funds from operations are 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 such as transaction costs related to acquisitions. 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.

Funds from operations are calculated from the Consolidated Statements 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.

## RESULTS OF OPERATIONS BY REPORTING SEGMENT

**Normalized Operating Income** [1]

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Gas | **$ 26** | $ 39 | **$ 78** | $ 126 |
| Power | **42** | 19 | **75** | 49 |
| Utilities | **13** | 8 | **121** | 109 |
| Sub-total: Operating Segments | **81** | 66 | **274** | 284 |
| Corporate | **(12)** | (7) | **(26)** | (23) |
| | **$ 69** | $ 59 | **$ 248** | $ 261 |

*(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, | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Total inlet gas processed (Mmcf/d)(1) | **1,293** | 1,447 | **1,304** | 1,499 |
| Extraction ethane volumes (Bbls/d)(1) | **30,241** | 35,395 | **30,539** | 34,051 |
| Extraction NGL volumes (Bbls/d)(1) | **30,922** | 37,574 | **30,665** | 37,569 |
| Total extraction volumes (Bbls/d)(1) (2) | **61,163** | 72,969 | **61,204** | 71,620 |
| Frac spread - realized ($/Bbl)(1) (3) | **34.58** | 14.19 | **19.21** | 19.24 |
| Frac spread - average spot price ($/Bbl)(1) (4) | **11.11** | 16.58 | **5.12** | 23.55 |

*(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, divided by the respective frac exposed volumes for the period.*

Total inlet gas processed for the three and nine months ended September 30, 2015 decreased by 154 and 195 Mmcf/d, respectively, compared to the same periods in 2014. The decreases were primarily driven by lower volumes at certain extraction plants, the shut-in by the third party operator of the Empress Gas Liquids Joint Venture (EGLJV) plant, lower processed volumes at Younger and the impact of pipeline curtailments downstream of certain AltaGas processing facilities. Significantly lower commodity prices in 2015 also made extraction of certain NGL at some of the facilities uneconomical resulting in reinjection. Turnarounds at Harmattan and Younger during second quarter 2015 also impacted volumes on a year-to-date basis.

Average ethane volumes for the three and nine months ended September 30, 2015 decreased by 5,154 and 3,512 Bbls/d, respectively, and NGL volumes decreased by 6,652 and 6,904 Bbls/d, respectively, compared to the same periods in 2014. Lower ethane volumes for third quarter and year-to-date 2015 were due to lower produced volumes at EGLJV and Edmonton Ethane Extraction Plant (EEEP) facilities. NGL volumes throughout the first nine months of 2015 were impacted by the lower commodity price environment resulting in reinjections. Turnarounds at Harmattan and Younger during second quarter 2015 also impacted ethane and NGL volumes on a year-to-date basis.

**Three Months Ended September 30**

The Gas segment reported normalized operating income of $26 million in third quarter 2015, compared to $39 million in same quarter 2014. The decrease in operating income reflects the significantly lower commodity price environment, lower processed volumes, lower earnings from Petrogas as well as the impact of pipeline curtailments downstream of certain gas processing facilities. During third quarter 2015, AltaGas recorded equity earnings of $5 million from Petrogas as compared to $8 million in same quarter 2014. EBITDA at the Petrogas level was roughly flat quarter over quarter as higher earnings from Ferndale during third quarter 2015 were generally offset by lower earnings from Petrogas' margin-based business and the impact of reduced activities in the upstream oil and gas sector. The overall decrease in equity earnings was largely driven by increased interest and depreciation related to Ferndale and other new assets placed into service at Petrogas.

During third quarter 2015, AltaGas hedged approximately 3,000 Bbls/d of NGL at an average price of $27/Bbl. During third quarter 2014, AltaGas hedged 5,000 Bbls/d of NGL at an average price of $24/Bbl. The average indicative spot NGL frac spread for third quarter 2015 was approximately $11/Bbl compared to approximately $17/Bbl in same quarter 2014. Realized frac spread of $35/Bbl in third quarter 2015 (2014 - $14/Bbl) was higher compared to the same period in 2014 due to realized gains on NGL frac hedges combined with propane reinjection resulting in approximately all of total production being hedged in the quarter.

**Nine Months Ended September 30**

The Gas segment reported normalized operating income of $78 million in nine months ended September 30, 2015, compared to $126 million in same period 2014. The decrease reflects the impact of weak NGL prices, lower earnings from Petrogas, completion of the two major turnarounds at Younger and Harmattan during second quarter 2015, lower throughput at certain gas processing facilities as well as the impact of third party pipeline curtailments downstream of certain AltaGas processing facilities. Partially offsetting these decreases was improved results from Energy Services due to unusually high costs incurred in first quarter 2014 to fulfill delivery commitments from operational curtailments resulting from extremely cold weather in eastern North America.

For the nine months ended September 30, 2015, AltaGas recorded equity earnings of $7 million from Petrogas as compared to $23 million from the same period in 2014. The decrease in Petrogas earnings was due to lower earnings from Petrogas' margin based business, impact of reduced activities in the upstream oil and gas sector and higher depreciation and interest related to Ferndale and other new assets placed into service at Petrogas, partially offset by higher margins from Ferndale. Market conditions were particularly favourable in the first quarter of 2014, which contributed to Petrogas' strong 2014 earnings. Petrogas' earnings in 2015 were impacted by depressed commodity market conditions as well as a planned maintenance shutdown at Ferndale in first quarter 2015.

During the nine months ended September 30, 2015, AltaGas hedged approximately 3,100 Bbls/d of NGL volumes at an average price of $27/Bbl. During nine months ended September 30, 2014, AltaGas hedged 5,200 Bbls/d of NGL at an average price of $25/Bbl. The average indicative spot NGL frac spread for nine months ended September 30, 2015 was approximately $5/Bbl compared to approximately $24/Bbl in same period 2014.

**POWER**

**OPERATING STATISTICS**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Volume of power sold (GWh) | **1,697** | 1,464 | **4,134** | 3,712 |
| Average Alberta realized power price ($/MWh) | **38.80** | 67.69 | **44.09** | 61.89 |
| Average price realized on the sale of power ($/MWh) (1) | **72.89** | 74.51 | **65.97** | 66.63 |
| Alberta Power Pool average spot price ($/MWh) | **26.09** | 64.34 | **37.43** | 55.80 |

*(1) Price received excludes Blythe as it earns fixed capacity payments under its power purchase agreement with Southern California Edison (SCE).*

During third quarter 2015, volume of power sold increased by 233 GWh compared to same quarter 2014. Volumes sold during third quarter 2015 were comprised of 1,210 GWh conventional power generation and 487 GWh of renewable power generation, compared to 1,309 GWh conventional power generation and 155 GWh renewable power generation in same quarter 2014.

During the nine months ended September 30, 2015, volume of power sold increased by 422 GWh compared to same period in 2014. Volumes sold during nine months ended September 30, 2015 were comprised of 3,144 GWh of conventional power generation and 990 GWh renewable power generation, compared to 3,321 GWh conventional power generation and 391 GWh renewable power generation in same period 2014. The change in the generation composition was due to renewable volumes from Forrest Kerr and Volcano Creek, as well as the impact of the new U.S. natural gas-fired assets acquired in January 2015, which were offset by decreasing conventional volumes due to the disposition of the Alberta peakers in late 2014 and weak Alberta realized power prices with associated volume impacts.

**Three Months Ended September 30**

The Power segment reported normalized operating income of $42 million for third quarter 2015, compared to $19 million for same quarter 2014. Normalized operating income increased as a result of the full quarter contributions from Forrest Kerr and Volcano Creek and the new U.S. natural gas-fired power assets acquired in January 2015, and the impact of the strong US dollar. These increases were partially offset by the impact of weaker Alberta realized power prices. The average Alberta power pool spot price dropped to a record low in third quarter 2015 of $26/MWh. In addition, earnings from Forrest Kerr for third quarter

2015 were adversely impacted by below seasonal average rainfall, which combined with the smaller snowpack this year, produced lower than average river flows. AltaGas also curtailed production to complete environmental testing during max flow condition as required under the terms of its water license. As a result, normalized EBITDA for Forrest Kerr was approximately $5 million lower than expected.

In third quarter 2015, AltaGas was 51 percent hedged in Alberta at an average price of $50/MWh. In third quarter 2014, AltaGas was 55 percent hedged at an average price of $67/MWh.

During the third quarter 2015, AltaGas recorded a pre-tax provision of $11 million related to the planned sale of certain development stage wind assets in northern California.

**Nine Months Ended September 30**

The Power segment reported normalized operating income of $75 million for nine months ended September 30, 2015, compared to $49 million for same period 2014. Normalized operating income increased as compared to same period 2014 due to the contributions from Forrest Kerr and Volcano Creek, lower Sundance costs, favourable exchange rates, impact of the new U.S. natural gas-fired assets acquired in January 2015 and increased results from Blythe due to a major planned maintenance turnaround in early 2014. This was partially offset by lower Alberta realized power prices and volumes.

For the nine months ended September 30, 2015, AltaGas was 51 percent hedged in Alberta at an average price of $51/MWh. AltaGas was 54 percent hedged at an average price of $64/MWh for the same period in 2014.

## UTILITIES

### OPERATING STATISTICS

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Canadian utilities | | | | |
| Natural gas deliveries - end-use (PJ)[1] | **3.3** | 3.1 | **21.6** | 22.1 |
| Natural gas deliveries - transportation (PJ)[1] | **1.6** | 1.0 | **5.0** | 4.1 |
| U.S. utilities | | | | |
| Natural gas deliveries - end-use (Bcf)[1] | **5.9** | 6.1 | **48.0** | 49.2 |
| Natural gas deliveries - transportation (Bcf)[1] | **10.5** | 8.5 | **34.2** | 29.3 |
| Service sites [2] | **562,301** | 554,837 | **562,301** | 554,837 |
| Degree day variance from normal - AUI (%) [3] | **3.9** | (6.2) | **(10.0)** | 5.8 |
| Degree day variance from normal - Heritage Gas (%) [3] | **(42.0)** | (1.5) | **11.9** | 3.6 |
| Degree day variance from normal - SEMCO Gas (%) [4] | **(28.4)** | 44.7 | **10.9** | 22.0 |
| Degree day variance from normal - ENSTAR (%) [4] | **(9.6)** | (8.3) | **(10.6)** | (8.1) |

*(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 operating income of $13 million in third quarter 2015, compared to $8 million in same quarter 2014. The increase was mainly due to the impact of rate base and customer growth across all Utilities, the favourable foreign exchange rates and the early approval of SEMCO Gas' Main Replacement Program. The increase in operating income was partially offset by warmer weather experienced at the U.S. utilities and in Nova Scotia.

**Nine Months Ended September 30**

The Utilities segment reported operating income of $121 million in nine months ended September 30, 2015, compared to $109 million in same period 2014. The increase was mainly due to rate base and customer growth across all Utilities, favourable foreign exchange rates, the early approval of SEMCO Gas' Main Replacement Program and colder weather experienced in Nova Scotia. The increase in operating income was partially offset by warmer weather experienced at the U.S. Utilities and in Alberta, and higher operating costs due to increased pension, retiree medical, and severance costs.

On June 3, 2015, SEMCO Gas' Main Replacement Program case was approved by the Michigan Public Service Commission. This program was for the recovery of capital expenses projected from 2016 to 2020 combined with a reconciliation of the current program that expires in December 2015. The new rates took effect immediately, resulting in approximately US$2 million of additional operating income for the nine months ended September 30, 2015.

**CORPORATE**

**Three Months Ended September 30**

In the Corporate segment, normalized operating loss for third quarter 2015 was $12 million, compared to $7 million in same quarter 2014. The increase in normalized operating loss was primarily due to higher salaries and benefits expense and higher depreciation expense related to major IT projects.

**Nine Months Ended September 30**

Normalized operating loss for the first nine months 2015 was $26 million, compared to $23 million in same period 2014. The increase in normalized operating loss was due to the same reasons discussed above.

**INVESTED CAPITAL**

During third quarter 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $181 million, compared to $199 million in same quarter 2014.

During third quarter 2015, the Power segment paid $11 million (2014 - $5 million) to BC Hydro in support of the construction and operation of the Northwest Transmission Line.

The invested capital in third quarter 2015 included maintenance capital of $6 million (2014 - $3 million) in the Gas segment and $1 million (2014 - $nil) in the Power segment.

**Invested Capital - Investment Type**

| | Three Months Ended September 30, 2015 | | | | |
|---|---|---|---|---|---|
| *($ millions)* | **Gas** | **Power** | **Utilities** | **Corporate** | **Total** |
| Invested capital: | | | | | |
| Property, plant and equipment | **$ 53** | **$ 54** | **$ 54** | **$ 3** | **$ 164** |
| Intangible assets | **—** | **11** | **1** | **2** | **14** |
| Long-term investments | **3** | **—** | **—** | **—** | **3** |
| Invested capital | **56** | **65** | **55** | **5** | **181** |
| Disposals: | | | | | |
| Property, plant and equipment | **—** | **—** | **—** | **—** | **—** |
| Net Invested capital | **$ 56** | **$ 65** | **$ 55** | **$ 5** | **$ 181** |

| | Three Months Ended September 30, 2014 | | | | |
|---|---|---|---|---|---|
| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
| Invested capital: | | | | | |
| Property, plant and equipment | $ 26 | $ 60 | $ 49 | $ 1 | $ 136 |
| Intangible assets | — | 5 | — | 5 | 10 |
| Long-term investments | 3 | — | — | 50 | 53 |
| | 29 | 65 | 49 | 56 | 199 |
| Disposals: | | | | | |
| Property, plant and equipment | — | — | — | — | — |
| Net Invested capital | $ 29 | $ 65 | $ 49 | $ 56 | $ 199 |

During the nine months ended September 30, 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $462 million, compared to $461 million in same period 2014. The net invested capital was $462 million for the nine months ended September 30, 2015, compared to $434 million in same period 2014.

The invested capital for nine months ended September 30, 2015 included maintenance capital of $18 million (2014 - $6 million) in the Gas segment and $2 million (2014 - $nil) in the Power segment. Gas segment maintenance capital included $8 million related to the Harmattan turnaround during second quarter 2015 (2014 - $nil).

**Invested Capital - Investment Type**

| | Nine Months Ended September 30, 2015 | | | | |
|---|---|---|---|---|---|
| *($ millions)* | **Gas** | **Power** | **Utilities** | **Corporate** | **Total** |
| Invested capital: | | | | | |
| Property, plant and equipment | **$ 124** | **$ 163** | **$ 125** | **$ 5** | **$ 417** |
| Intangible assets | **2** | **20** | **2** | **12** | **36** |
| Long-term investments | **9** | **—** | **—** | **—** | **9** |
| Invested capital | **135** | **183** | **127** | **17** | **462** |
| Disposals: | | | | | |
| Property, plant and equipment | **—** | **—** | **—** | **—** | **—** |
| Net Invested capital | **$ 135** | **$ 183** | **$ 127** | **$ 17** | **$ 462** |

| | Nine Months Ended September 30, 2014 | | | | |
|---|---|---|---|---|---|
| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
| Invested capital: | | | | | |
| Property, plant and equipment | $ 47 | $ 227 | $ 108 | $ 4 | $ 386 |
| Intangible assets | — | 5 | 1 | 13 | 19 |
| Long-term investments | 6 | — | — | 50 | 56 |
| | 53 | 232 | 109 | 67 | 461 |
| Disposals: | | | | | |
| Property, plant and equipment | (27) | — | — | — | (27) |
| Net Invested capital | $ 26 | $ 232 | $ 109 | $ 67 | $ 434 |

**RISK MANAGEMENT**

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During third quarter 2015, the Corporation had positions in the following types of derivatives, which are also disclosed in the unaudited condensed interim Consolidated Financial Statements:

**Commodity Forward Contracts**

The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price.

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of foreign exchange derivatives used quoted market rates.

AltaGas does not speculate on commodity prices and therefore does not engage in commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock in margins, optimize underlying physical assets or reduce exposure to energy price movements. AltaGas' risk management group reviews commodity and credit risk on a daily basis and has created and adheres to a conservative risk policy and hedging program.

**Commodity Swap Contracts**

Power hedges:

AltaGas executes fixed for floating power price swaps to manage its Alberta power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power segment results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $8.84/MWh to $920.08/MWh in third quarter 2015 and $8.91/MWh to $999.99/MWh in third quarter 2014. The average Alberta spot price was approximately $26/MWh in third quarter 2015 (third quarter 2014 - $64/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average realized Alberta power price was approximately $39/MWh in third quarter 2015 (third quarter 2014 - $68/MWh). For the remainder of 2015, AltaGas has hedged approximately 41 percent of expected volumes exposed to Alberta power prices at an average price of $48/MWh.

NGL frac spread hedges:

The Corporation 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. During third quarter 2015, the Corporation hedged approximately 3,000 Bbls/d of NGL at an average price of approximately $27/Bbl. The average indicative spot NGL frac spread for third quarter 2015 was an estimated $11/Bbl (third quarter 2014 – $17/Bbl). The average NGL frac spread realized by AltaGas in third quarter 2015 was approximately $35/Bbl (third quarter 2014 - $14/Bbl). Management estimates an average of approximately 6,400 Bbls/d will be exposed to frac spread for the remainder of 2015, of which 3,000 Bbls/d have been hedged at an average price of approximately $27/Bbl prior to deducting extraction premiums.

**Foreign Exchange**

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold. Foreign exchange gains and losses on long-term debt denominated in US dollars are unrealized and can only be realized when the long-term debt matures or is settled.

As at September 30, 2015, management designated US$364 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2014 - US$375 million). US dollar denominated long-term debts have been designated as a hedge of the net investment in foreign subsidiaries. This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on US dollar denominated long-term debt and foreign net investment.

## LIQUIDITY

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| ($ millions) | **2015** | 2014 | **2015** | 2014 |
| Cash from operations | **$ 60** | $ 73 | **$ 410** | $ 359 |
| Investing activities | **(181)** | (215) | **(431)** | (433) |
| Financing activities | **239** | 574 | **55** | 489 |
| Effect of exchange rate | **3** | 2 | **6** | 2 |
| Increase in cash and cash equivalents | **$ 121** | $ 434 | **$ 40** | $ 417 |

**Cash from Operations**

Cash from operations increased by $51 million for the nine months ended September 30, 2015 compared to the same period in 2014 primarily due to higher cash contributions from new assets placed into service and the favourable US dollar exchange rate, partially offset by lower commodity prices and volumes, and lower distributions from the Corporation's equity investments. No distribution from Petrogas was received in the first nine months of 2015, whereas $28 million of dividend was received from Petrogas in second quarter 2014. The increase in cash from operations was also impacted by the favourable variance in net change in operating assets and liabilities. The net change in operating assets and liabilities was a net cash inflow of $101 million for the nine months ended September 30, 2015 compared to $42 million for the same period in 2014. The higher net cash inflow is due to changes in inventory and regulatory assets largely as a result of changes in gas commodity costs, partially offset by an increase in payments for other assets.

| **Working Capital**<br>($ millions except current ratio) | **September 30, 2015** | December 31, 2014 |
|---|---|---|
| Current assets | **$ 916** | $ 1,058 |
| Current liabilities | **733** | 765 |
| Working capital | **$ 183** | $ 293 |
| Current ratio | **1.25** | 1.38 |

Working capital surplus was $183 million as at September 30, 2015, compared to $293 million as at December 31, 2014. The working capital ratio was 1.25 at the end of third quarter 2015, compared to 1.38 at December 31, 2014. The decrease in working capital ratio was primarily due to the decrease in accounts receivable, the maturity of a $50 million short-term investment during 2015, partially offset by higher cash and cash equivalents and lower accounts payable at September 30, 2015.

**Investing Activities**

Cash used in investing activities in nine months ended September 30, 2015 was $431 million, compared to $433 million in same period 2014. Investing activities in nine months ended September 30, 2015 included expenditures of $409 million for property, plant and equipment, $33 million for intangible assets and $34 million for business acquisition, partially offset by cash inflow of $50 million relating to the maturity of a short-term investment. Investing activities in nine months ended September 30, 2014 primarily comprised of $388 million for property, plant and equipment and $20 million for intangible assets, $50 million for acquisition of a long-term investment, partially offset by proceeds of $27 million received on disposition of assets.

**Financing Activities**

Cash from financing activities in nine months ended September 30, 2015 was $55 million, compared to $489 million in same period 2014. Financing activities in nine months ended September 30, 2015 were primarily comprised of net proceeds from issuance of common shares of $367 million, issuance of long-term debt of $386 million, partially offset by repayments of long-term and short-term debts of $411 million and $67 million, respectively. Financing activities in nine months ended September 30, 2014 were primarily comprised of net proceeds from issuance of common shares of $507 million, issuance of preferred shares of $195 million, issuance of long-term debt of $1,047 million, partially offset by repayments of long-term and short-term debts of $1,025 million and $50 million, respectively. Total dividends paid in nine months ended September 30, 2015 were $216 million, compared to $176 million in same period 2014. The increase was due to more common shares outstanding and dividend increases declared in 2014 and 2015.

## CAPITAL RESOURCES

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

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

| ($ millions) | **September 30, 2015** | December 31, 2014 |
|---|---|---|
| Short-term debt | **$ 15** | $ 72 |
| Current portion of long-term debt | **279** | 214 |
| Long-term debt[(1)] | **3,080** | 3,032 |
| Total debt | **3,374** | 3,318 |
| Less: cash and cash equivalent | **(410)** | (371) |
| Less: short-term investments | **—** | (50) |
| Net debt | **$ 2,964** | $ 2,897 |
| Shareholders' equity | **3,981** | 3,541 |
| Non-controlling interests | **36** | 33 |
| Total capitalization | **$ 6,981** | $ 6,471 |
| Debt-to-total capitalization (%) | **42** | 45 |

*(1) Net of debt issuance costs of $16 million as at September 30, 2015 (December 31, 2015 - $18 million).*

As at September 30, 2015, AltaGas’ total debt primarily consisted of MTNs of $2,760 million (December 31, 2014 - $2,760 million), PNG debenture notes of $55 million (December 31, 2014 - $57 million), SEMCO long-term debt of $505 million (December 31, 2014 - $443 million) and $62 million drawn under the bank credit facilities (December 31, 2014 - $46 million). In addition, AltaGas had $151 million of letters of credits (December 31, 2014 - $136 million) outstanding.

As at September 30, 2015, AltaGas’ total market capitalization was approximately $5.3 billion based on approximately 145 million common shares, approximately 6 million series A Preferred Shares, approximately 2 million series B Preferred Shares, 8 million series C US$ Preferred Shares, 8 million series E Preferred Shares and 8 million series G Preferred Shares outstanding and a closing trading price on September 30, 2015 of $32.88 per common share, $15.54 per series A Preferred Share, $15.51 per series B Preferred Share, $18.60 per series C US$ Preferred Share, $18.60 per series E Preferred Share, and $18.65 per series G Preferred Share, respectively.

AltaGas' earnings interest coverage for the rolling twelve months ended September 30, 2015 was 1.9 times.

**Credit Facilities**

| *($ millions)* | Borrowing capacity | **Drawn at September 30, 2015** | Drawn at December 31, 2014 |
|---|---|---|---|
| Demand operating facilities | $ 70 | **$ 4** | $ 4 |
| Extendible revolving letter of credit facility | 150 | **62** | 113 |
| Letter of credit demand facility | 100 | **78** | — |
| PNG operating facility | 25 | **17** | 14 |
| Bilateral letter of credit facility (1) | — | **—** | 13 |
| AltaGas Ltd. revolving credit facility (2) | 1,400 | **51** | — |
| SEMCO Energy US$ unsecured credit facility (2) (3) | 150 | **1** | 38 |
| | $ 1,895 | **$ 213** | $ 182 |

*(1) Effective September 2015, the bilateral letter of credit facility was closed.*

*(2) Amount drawn at September 30, 2015 converted at September 2015 month-end rate of 1 US dollar = 1.3394 Canadian dollar (December 31, 2014 - 1 US dollar = 1.1601 Canadian dollar).*

*(3) Borrowing capacity assumed at par.*

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, 2015** |
|---|---|---|
| Bank debt-to-capitalization (1) | not greater than 65 percent | 40% |
| Bank EBITDA-to-interest expense (1) (2) | not less than 2.5x | 3.7 |
| Bank debt-to-capitalization (SEMCO) (3) | not greater than 60 percent | 38% |
| Bank EBITDA-to-interest expense (SEMCO) (3) | not less than 2.25x | 6.8 |

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

*(2) Estimated, subject to final adjustments.*

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

On August 10, 2015, a $5 billion base shelf prospectus was filed. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remains effective, by disclosing standardized information required for such issuances. As at September 30, 2015, $4.7 billion remains available under the base shelf prospectus.

## SHARE INFORMATION

On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

On September 30, 2015, 2,488,780 of the outstanding 8,000,000 Cumulative Redeemable Five Year Fixed Rate Reset Preferred Shares, Series A were converted into Cumulative Floating Rate Preferred Shares, Series B.

| | As at October 20, 2015 |
|---|---|
| **Issued and outstanding** | |
| Common shares | 145,287,215 |
| 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 |
| **Issued** | |
| Share options | 4,928,248 |
| Share options exercisable | 2,815,686 |

**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 as impacted by the consolidated net income, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

On April 30, 2015, the Board of Directors approved an increase in the monthly dividend to $0.16 per common share from $0.1475 per common share effective with the May dividend.

On September 18, 2015, the Board of Directors approved an increase in the monthly dividend to $0.165 per common share from $0.16 per common share effective with the October dividend.

On September 30, 2015, the Series A preferred shares annual fixed dividend rate was reset to 3.38 percent. The dividend rate will reset on September 30, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent.

The Series B preferred shares will pay a floating quarterly dividend for the five-year period beginning on September 30, 2015. The floating quarterly dividend rate for Series B preferred shares for the first quarterly floating rate period (being the period from September 30, 2015 to but excluding December 31, 2015) is 3.04 percent and will be reset every quarter at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill plus 2.66 percent.

The following table summarizes AltaGas' dividend declaration history:

**Dividends**
Years ended December 31

| *($ per common share)* | **2015** | 2014 |
|---|---|---|
| First quarter | **$ 0.4425** | $ 0.3825 |
| Second quarter | **0.4675** | 0.4225 |
| Third quarter | **0.4800** | 0.4425 |
| Fourth quarter | **—** | 0.4425 |
| **Total** | **$ 1.3900** | $ 1.6900 |

**Series A Preferred Share Dividends**
Years ended December 31

| *($ per preferred share)* | | **2015** | | 2014 |
|---|---|---|---|---|
| First quarter | **$** | **0.3125** | $ | 0.3125 |
| Second quarter | | **0.3125** | | 0.3125 |
| Third quarter | | **0.3125** | | 0.3125 |
| Fourth quarter | | **—** | | 0.3125 |
| **Total** | **$** | **0.9375** | $ | 1.2500 |

**Series B Preferred Share Dividends**
Years ended December 31

| *($ per preferred share)* | | **2015** | | 2014 |
|---|---|---|---|---|
| Fourth quarter | **$** | **—** | $ | — |
| **Total** | **$** | **—** | $ | — |

**Series C Preferred Share Dividends**
Years ended December 31

| *(US$ per preferred share)* | | **2015** | | 2014 |
|---|---|---|---|---|
| First quarter | **$** | **0.2750** | $ | 0.2750 |
| Second quarter | | **0.2750** | | 0.2750 |
| Third quarter | | **0.2750** | | 0.2750 |
| Fourth quarter | | **—** | | 0.2750 |
| **Total** | **$** | **0.8250** | $ | 1.1000 |

**Series E Preferred Share Dividends**
Years ended December 31

| *($ per preferred share)* | | **2015** | | 2014 |
|---|---|---|---|---|
| First quarter | **$** | **0.3125** | $ | 0.3699 |
| Second quarter | | **0.3125** | | 0.3125 |
| Third quarter | | **0.3125** | | 0.3125 |
| Fourth quarter | | **—** | | 0.3125 |
| **Total** | **$** | **0.9375** | $ | 1.3074 |

**Series G Preferred Share Dividends**
Years ended December 31

| *($ per preferred share)* | | **2015** | | 2014 |
|---|---|---|---|---|
| First quarter | **$** | **0.2969** | $ | — |
| Second quarter | | **0.2969** | | — |
| Third quarter | | **0.2969** | | 0.2896 |
| Fourth quarter | | **—** | | 0.2969 |
| **Total** | **$** | **0.8907** | $ | 0.5865 |

## SIGNIFICANT ACCOUNTING POLICIES

Reference should be made to the audited Consolidated Financial Statements as at and for the year ended December 31, 2014 for information on accounting policies and practices.

## CRITICAL ACCOUNTING ESTIMATES

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

AltaGas' critical accounting estimates continue to be financial instruments, depreciation and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessment, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities. For a full discussion of these accounting estimates, refer to the MD&A in AltaGas' 2014 Financial Report and the notes to the unaudited condensed interim Consolidated Financial Statements for the three and nine months ended September 30, 2015.

**ADOPTION OF NEW ACCOUNTING STANDARD**

Effective July 1, 2015, AltaGas early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) 2015-03 “Simplifying the Presentation of Debt Issuance Costs”. Under the ASU, debt issuance costs are recorded as a direct deduction from the related debt liability rather than as an asset. Upon adoption, AltaGas reclassified debt issuance costs of $16 million and $18 million for the periods ended June 30, 2015 and December 31, 2014, respectively, from “Long-term investments and other assets” to “Long-term debt”. Debt issuance costs related to line-of-credit arrangements were not reclassified pursuant to guidance from ASU 2015-15 “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements”.

Effective August 2015, AltaGas prospectively adopted FASB issued ASU No. 2015-13 “Derivatives and Hedging - Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets”, which allows certain forward contracts for physical delivery of electricity in nodal energy markets to qualify for the normal purchases and normal sales scope exception, as long as the physical delivery criterion and other criteria of the normal purchases and normal sales scope exception are met. The ASU applies to forward contracts in which one of the counterparties incurs location marginal pricing charges (or credits) payable to (or receivable from) an independent system operator. The adoption of this ASU did not have an impact on AltaGas' consolidated financial statements.

**FUTURE CHANGES IN ACCOUNTING PRINCIPLES**

In May 2014, FASB issued ASU 2014-09, "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. On July 9, 2015, FASB confirmed a one-year deferral of the new revenue standard. The new standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Early adoption prior to that date would not be permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In February 2015, FASB issued ASU No. 2015-02 “Consolidation: Amendments to Consolidation Analysis”. The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The amendments in this ASU are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

**OFF-BALANCE SHEET ARRANGEMENTS**

Reference should be made to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2014 for information on off-balance sheet arrangements.

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

AltaGas' management 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.

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 material information relating to AltaGas' business 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.

On January 1, 2015, AltaGas launched a new ERP system, JD Edwards EnterpriseOne. The changes to the internal controls over financial reporting are included in the assessment to ensure that DCP and ICFR are designed to provide reasonable assurance that material information relating to AltaGas' business is made known, reliably reported on a timely basis, and financial statements are in accordance with U.S. GAAP.

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

| *($ millions)* | **Q3-15** | Q2-15 | Q1-15 | Q4-14 | Q3-14 | Q2-14 | Q1-14 | Q4-13 |
|---|---|---|---|---|---|---|---|---|
| Total revenue | **452** | 416 | 744 | 667 | 444 | 471 | 824 | 581 |
| Net revenue(2) | **268** | 204 | 307 | 285 | 217 | 220 | 297 | 265 |
| Normalized operating income(2) | **69** | 54 | 125 | 105 | 59 | 64 | 137 | 112 |
| Net income (loss) applicable to common shares | **20** | (22) | 66 | 10 | 17 | 29 | 40 | 53 |
| *($ per share)* | **Q3-15** | Q2-15 | Q1-15 | Q4-14 | Q3-14 | Q2-14 | Q1-14 | Q4-13 |
| Net income (loss) per common shares | | | | | | | | |
| Basic | **0.15** | (0.16) | 0.49 | 0.08 | 0.13 | 0.23 | 0.33 | 0.44 |
| Diluted | **0.14** | (0.16) | 0.49 | 0.08 | 0.13 | 0.23 | 0.32 | 0.43 |
| Dividends declared | **0.48** | 0.47 | 0.44 | 0.44 | 0.44 | 0.42 | 0.38 | 0.38 |

*(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, the US/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 quarter of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March. Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The commissioning of the hydroelectric power generating facilities, Forrest Kerr and Volcano Creek during the latter part of 2014. These run-of-river hydro facilities are impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months;
- The acquisition of U.S. natural gas-fired power assets in first quarter 2015;
- The Harmattan and Younger turnarounds in second quarter 2015;

- The weak NGL commodity prices during the latter part of 2014 and year-to-date 2015; and
- The stronger US dollar on translated results of the U.S. assets throughout 2015.

Net income (loss) applicable to common shares are also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on long-lived assets and gain or loss on asset dispositions. In addition, net income (loss) applicable to common shares is also impacted by preferred shares dividend. 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 were impacted by:

- An after-tax provision of $37 million for EDS and JFP transmission pipeline assets and certain hydro power development assets recorded in first quarter 2014;
- Higher interest and depreciation and amortization expense since third quarter 2014 due to new assets placed into service and interest no longer eligible for capitalization;
- An after-tax provision of $52 million for certain gas processing assets in fourth quarter 2014;
- A one-time non-cash expense of $14 million related to the revaluation of deferred income tax liabilities based on the increased Alberta corporate income tax rate from 10 to 12 percent in second quarter 2015; and
- An after-tax provision of $6 million related to the planned sale of certain development stage wind assets in northern California.

# Consolidated Balance Sheets

(condensed and unaudited)

| **As at** *($ millions)* | **September 30, 2015** | December 31, 2014 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 409.9** | $ 371.0 |
| Short-term investment | **—** | 50.0 |
| Accounts receivable, net of allowances | **239.0** | 352.4 |
| Inventory *(note 6)* | **170.2** | 155.3 |
| Restricted cash holdings from customers | **4.0** | 4.2 |
| Regulatory assets | **2.7** | 12.8 |
| Risk management assets *(note 9)* | **30.6** | 70.8 |
| Prepaid expenses and other current assets | **57.0** | 41.9 |
| Deferred income taxes | **2.4** | — |
| | **915.8** | 1,058.4 |
| **Property, plant and equipment** | **5,878.7** | 5,337.0 |
| **Intangible assets** | **368.2** | 356.9 |
| **Goodwill** *(note 7)* | **863.0** | 785.1 |
| **Regulatory assets** | **329.9** | 302.0 |
| **Risk management assets** *(note 9)* | **20.8** | 21.1 |
| **Deferred income taxes** | **19.4** | 2.2 |
| **Restricted cash holdings from customers** | **12.1** | 12.2 |
| **Long-term investments and other assets** | **76.3** | 66.8 |
| **Investments accounted for by equity method** | **475.0** | 453.9 |
| | **$ 8,959.2** | $ 8,395.6 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | **$ 315.7** | $ 343.6 |
| Dividends payable | **21.8** | 19.8 |
| Short-term debt | **15.3** | 72.4 |
| Current portion of long-term debt *(note 8)* | **279.3** | 214.4 |
| Customer deposits | **37.5** | 34.9 |
| Regulatory liabilities | **17.9** | 10.0 |
| Risk management liabilities *(note 9)* | **20.1** | 43.5 |
| Deferred income taxes | **0.3** | 2.1 |
| Other current liabilities *(note 10)* | **25.2** | 24.4 |
| | **733.1** | 765.1 |
| **Long-term debt** *(note 8)* | **3,079.5** | 3,031.8 |
| **Asset retirement obligations** | **74.7** | 70.9 |
| **Deferred income taxes** *(note 15)* | **534.3** | 467.2 |
| **Regulatory liabilities** | **158.0** | 136.0 |
| **Risk management liabilities** *(note 9)* | **14.8** | 14.7 |
| **Other long-term liabilities** *(note 10)* | **204.6** | 204.5 |
| **Future employee obligations** | **142.4** | 131.2 |
| | **$ 4,941.4** | $ 4,821.4 |

| **As at** ($ millions) | | **September 30, 2015** | | December 31, 2014 |
|---|---|---|---|---|
| **Shareholders' equity** | | | | |
| Common shares, no par values, unlimited shares authorized; 2015 - 145.0 million and 2014 - 133.9 million issued and outstanding *(note 11)* | **$** | **3,131.3** | $ | 2,759.9 |
| Preferred shares *(note 11)* | | **788.4** | | 788.4 |
| Contributed surplus | | **16.1** | | 14.9 |
| Accumulated deficit | | **(308.9)** | | (185.2) |
| Accumulated other comprehensive income (AOCI) *(note 3)* | | **354.5** | | 163.1 |
| **Total shareholders' equity** | | **3,981.4** | | 3,541.1 |
| **Non-controlling interests** | | **36.4** | | 33.1 |
| **Total equity** | | **4,017.8** | | 3,574.2 |
| | **$** | **8,959.2** | $ | 8,395.6 |

*Commitments and contingencies (note 13).*

*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, **2015** | 2014 | Nine Months Ended September 30, **2015** | 2014 |
|---|---|---|---|---|
| **REVENUE** | | | | |
| Sales | **$ 88.5** | $ 191.9 | **$ 301.5** | $ 627.6 |
| Services | **208.9** | 121.2 | **560.1** | 370.7 |
| Regulated operations | **143.4** | 130.8 | **749.3** | 744.3 |
| Other revenue (loss) | **0.6** | (0.8) | **0.4** | (1.7) |
| Unrealized gain (loss) on risk management contracts *(note 9)* | **10.8** | 1.1 | **1.6** | (1.7) |
| | **452.2** | 444.2 | **1,612.9** | 1,739.2 |
| **EXPENSES** | | | | |
| Cost of sales, exclusive of items shown separately | **179.9** | 241.4 | **832.4** | 1,055.9 |
| Operating and administrative | **134.1** | 112.5 | **372.2** | 336.3 |
| Accretion expenses | **2.7** | 2.0 | **8.2** | 4.1 |
| Depreciation and amortization | **52.9** | 43.6 | **152.5** | 126.6 |
| Provision on long-lived assets *(note 4)* | **10.5** | — | **10.5** | 49.2 |
| | **380.1** | 399.5 | **1,375.8** | 1,572.1 |
| **Income (loss) from equity investments** | **(5.0)** | 13.4 | **(5.4)** | 38.0 |
| **Other income** | **1.1** | 1.2 | **5.3** | 12.6 |
| **Foreign exchange gain (loss)** | **—** | (0.5) | **0.4** | (0.3) |
| **Interest expense** | | | | |
| Short-term debt | **(0.5)** | (0.3) | **(1.2)** | (1.0) |
| Long-term debt | **(30.9)** | (28.3) | **(90.4)** | (75.9) |
| **Income before income taxes** | **36.8** | 30.2 | **145.8** | 140.5 |
| **Income tax expense (recovery)** *(note 15)* | | | | |
| Current | **2.2** | (1.4) | **17.2** | 12.6 |
| Deferred | **2.4** | 3.2 | **27.7** | 11.8 |
| **Net income after taxes** | **32.2** | 28.4 | **100.9** | 116.1 |
| **Net income applicable to non-controlling interests** | **2.1** | 2.0 | **6.2** | 6.1 |
| **Net income applicable to controlling interests** | **30.1** | 26.4 | **94.7** | 110.0 |
| **Preferred share dividends** | **(10.3)** | (9.8) | **(30.5)** | (24.6) |
| **Net income applicable to common shares** | **$ 19.8** | $ 16.6 | **$ 64.2** | **$** 85.4 |
| **Net income per common share** *(note 12)* | | | | |
| Basic | **$ 0.15** | $ 0.13 | **$ 0.48** | $ 0.69 |
| Diluted | **$ 0.14** | $ 0.13 | **$ 0.47** | $ 0.68 |
| **Weighted average number of common shares outstanding** (millions) *(note 12)* | | | | |
| Basic | **135.8** | 127.1 | **135.0** | 124.3 |
| Diluted | **136.6** | 129.2 | **136.2** | 126.3 |

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Comprehensive Income

(condensed and unaudited)

| ($ millions) | Three Months Ended September 30, 2015 | Three Months Ended September 30, 2014 | Nine Months Ended September 30, 2015 | Nine Months Ended September 30, 2014 |
|---|---|---|---|---|
| Net income after taxes | **$ 32.2** | $ 28.4 | **$ 100.9** | $ 116.1 |
| Other comprehensive income (loss), net of taxes | | | | |
| Gain on foreign currency translation | **143.3** | 81.0 | **277.8** | 87.1 |
| Unrealized loss on net investment hedge | **(32.9)** | (20.1) | **(62.6)** | (22.2) |
| Unrealized gains (losses) on cash flow hedges | **—** | 2.0 | **(0.2)** | 7.4 |
| Reclassification of gains on cash flow hedges to net income | **—** | (1.0) | **(13.1)** | — |
| Funded status adjustment associated with defined benefit pension plans | **—** | — | **—** | 0.1 |
| Reclassification of actuarial losses and prior service costs on defined benefit and post-retirement benefit plans (PRB) to net income | **0.4** | 0.1 | **0.9** | 0.1 |
| Unrealized gain (loss) on available-for-sale assets | **(11.0)** | 1.7 | **(16.0)** | 2.0 |
| Other comprehensive income (loss) from equity investees | **(0.3)** | — | **4.6** | — |
| Total other comprehensive income, net of taxes | **99.5** | 63.7 | **191.4** | 74.5 |
| **Comprehensive income attributable to common shareholders and non-controlling interests, net of taxes** | **$ 131.7** | $ 92.1 | **$ 292.3** | $ 190.6 |
| **Comprehensive income attributable to:** | | | | |
| Non-controlling interests | **$ 2.1** | $ 2.0 | **$ 6.2** | $ 6.1 |
| Controlling interests | **129.6** | 90.1 | **286.1** | 184.5 |
| | **$ 131.7** | $ 92.1 | **$ 292.3** | $ 190.6 |

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Equity

(condensed and unaudited)

| *($ millions)* | Nine Months Ended September 30, **2015** | 2014 |
|---|---|---|
| **Common shares** *(note 11)* | | |
| Balance, beginning of period | **$ 2,759.9** | $ 2,211.4 |
| Shares issued for cash on exercise of options | **11.8** | 17.6 |
| Shares issued under DRIP [1] | **68.5** | 49.7 |
| Deferred taxes on share issuance costs | **3.1** | 4.7 |
| Shares issued on public offering | **288.0** | 441.7 |
| Balance, end of period | **$ 3,131.3** | $ 2,725.1 |
| **Preferred shares** *(note 11)* | | |
| Balance, beginning of period | **$ 788.4** | $ 589.6 |
| Series A converted to Series B | **(60.9)** | — |
| Series B issued | **60.9** | — |
| Series E issued | **—** | (0.4) |
| Series G issued | **—** | 196.3 |
| Balance, end of period | **$ 788.4** | $ 785.5 |
| **Contributed surplus** | | |
| Balance, beginning of period | **$ 14.9** | $ 13.4 |
| Share options expense | **2.6** | 3.0 |
| Exercise of share options | **(1.1)** | (1.6) |
| Forfeiture of share options | **(0.3)** | (0.1) |
| Balance, end of period | **$ 16.1** | $ 14.7 |
| **Accumulated deficit** | | |
| Balance, beginning of period | **$ (185.2)** | $ (62.1) |
| Net income applicable to controlling interests | **94.7** | 110.0 |
| Common share dividends | **(187.9)** | (155.2) |
| Preferred share dividends | **(30.5)** | (24.6) |
| Balance, end of period | **$ (308.9)** | $ (131.9) |
| **Accumulated other comprehensive income** (*note 3*) | | |
| Balance, beginning of period | **$ 163.1** | **$** 39.5 |
| Other comprehensive income | **191.4** | 74.5 |
| Balance, end of period | **$ 354.5** | **$** 114.0 |
| **Total shareholders' equity** | **$ 3,981.4** | **$** 3,507.4 |
| | | |
| **Non-controlling interests** | | |
| Balance, beginning of period | **$ 33.1** | $ 37.8 |
| Net income applicable to non-controlling interests | **6.2** | 6.1 |
| Sale of interest in a subsidiary | **1.8** | — |
| Distribution by subsidiaries to non-controlling interests | **(4.7)** | (9.3) |
| Balance, end of period | **36.4** | 34.6 |
| **Total equity** | **$ 4,017.8** | $ 3,542.0 |

[1] *Dividend Reinvestment and Optional Share Purchase Plan.*

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Cash Flows

(condensed and unaudited)

| ($ millions) | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| **Cash from operations** | | | | |
| Net income after taxes | **$ 32.2** | $ 28.4 | **$ 100.9** | $ 116.1 |
| Items not involving cash: | | | | |
| Depreciation and amortization | **52.9** | 43.6 | **152.5** | 126.6 |
| Provision on long-lived assets *(note 4)* | **10.5** | — | **10.5** | 49.2 |
| Accretion expenses | **2.7** | 2.0 | **8.2** | 4.1 |
| Share-based compensation *(note 11)* | **0.7** | 1.0 | **2.3** | 2.9 |
| Deferred income tax expense *(note 15)* | **2.4** | 3.2 | **27.7** | 11.8 |
| Gain on sale of assets | **—** | — | **—** | (11.1) |
| Loss (income) from equity investments | **5.0** | (13.4) | **5.4** | (38.0) |
| Unrealized (gain) loss on risk management contracts *(note 9)* | **(10.8)** | (1.1) | **(1.6)** | 1.7 |
| Unrealized (gain) loss on long-term investments | **—** | 0.4 | **(0.9)** | (0.1) |
| Losses from extinguishment of debts | **—** | — | **—** | 2.1 |
| Other | **1.5** | 1.6 | **5.8** | 0.9 |
| Asset retirement obligations settled | **(0.3)** | (0.3) | **(2.0)** | (1.0) |
| Distributions from (contributions to) equity investments | **4.8** | 14.2 | **(0.1)** | 51.4 |
| Changes in operating assets and liabilities *(note 16)* | **(41.8)** | (6.5) | **100.8** | 42.1 |
| | **$ 59.8** | $ 73.1 | **$ 409.5** | $ 358.7 |
| **Investing activities** | | | | |
| Change in restricted cash holdings from customers | **(0.7)** | 0.1 | **0.8** | (0.1) |
| Acquisition of property, plant and equipment | **(165.3)** | (151.7) | **(409.1)** | (388.3) |
| Acquisition of intangible assets | **(14.0)** | (10.3) | **(32.5)** | (19.8) |
| Proceeds from dispositions of assets | **0.1** | (0.2) | **0.2** | 27.2 |
| Maturity of short-term investment | **—** | — | **50.0** | — |
| Contributions to equity investments | **(2.9)** | (2.8) | **(9.0)** | (6.8) |
| Business acquisitions, net of cash acquired *(note 5)* | **—** | — | **(33.6)** | 5.0 |
| Acquisition of equity investment | **—** | (50.0) | **—** | (50.0) |
| Sale of interest in a subsidiary | **1.8** | — | **1.8** | — |
| | **$ (181.0)** | **$** (214.9) | $ **(431.4)** | **$** (432.8) |
| **Financing activities** | | | | |
| Net issuance (repayment) of short-term debt | **(2.7)** | 10.4 | **(66.6)** | (49.6) |
| Issuance of long-term debt, net of debt issuance costs | **10.3** | 300.6 | **386.2** | 1,046.8 |
| Repayment of long-term debt | **(7.0)** | (326.8) | **(410.7)** | (1,024.5) |
| Dividends - common shares | **(65.1)** | (54.8) | **(185.9)** | (151.2) |
| Dividends - preferred shares | **(10.3)** | (9.8) | **(30.5)** | (25.0) |
| Distributions to non-controlling interest | **(0.7)** | (3.1) | **(4.7)** | (9.3) |
| Net proceeds from shares issued on exercise of options | **0.3** | 2.7 | **10.7** | 16.0 |
| Net proceeds from issuance of common shares | **313.7** | 459.7 | **356.5** | 491.4 |
| Net proceeds from issuance of preferred shares | **—** | 195.0 | **—** | 194.5 |
| | **$ 238.5** | $ 573.9 | **$ 55.0** | $ 489.1 |
| **Change in cash and cash equivalents** | **117.3** | 432.1 | **33.1** | 415.0 |
| **Effect of exchange rate changes on cash and cash equivalents** | **3.0** | 2.1 | **5.8** | 2.3 |
| **Cash and cash equivalents, beginning of period** | **289.6** | 27.9 | **371.0** | 44.8 |
| **Cash and cash equivalents, end of period** | **$ 409.9** | $ 462.1 | **$ 409.9** | $ 462.1 |

*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 BUSINESS

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by the Corporation, and a number of its subsidiaries including, without limitation, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., AltaGas Services (U.S.) Inc., and Coast Mountain Hydro Limited Partnership.

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. 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 fractionation, gas transmission, gas storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas). AIJVLP also manages the liquefied natural gas (LNG) and the liquefied petroleum gas (LPG) export development projects. AltaGas is developing its Douglas Channel LNG project through its interest in AIJVLP.

The Power segment includes 1,449 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and the United States, along with an additional 81 MW of assets under construction and 2,360 MW of power generation in various stages of 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 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 2014 annual audited Consolidated Financial Statements prepared in accordance with U.S. GAAP. In management's opinion, the condensed interim Consolidated Financial Statements include all adjustments that are all of a recurring nature and necessary to present fairly the financial position of the Corporation.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date to which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

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

Transactions between and amongst, AltaGas and its wholly-owned subsidiaries, and the proportionate interests in joint ventures or partnerships are eliminated on consolidation as required by U.S. GAAP. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “Non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries is shown as an allocation of the consolidated net income and is 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 expense, asset retirement obligations, long-lived and intangible assets impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and 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 condensed interim Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2014 annual audited Consolidated Financial Statements.

**ADOPTION OF NEW ACCOUNTING STANDARDS**

Effective July 1, 2015, AltaGas early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2015-03 “Simplifying the Presentation of Debt Issuance Costs”. Under the ASU, debt issuance costs are recorded as a direct deduction from the related debt liability rather than as an asset. Upon adoption, AltaGas reclassified debt issuance costs of $16.1 million and $17.8 million for the periods ended June 30, 2015 and December 31, 2014, respectively, from “Long-term investments and other assets” to “Long-term debt”. Debt issuance costs related to line-of-credit arrangements were not reclassified pursuant to guidance from ASU No. 2015-15 “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements”.

Effective August 2015, AltaGas prospectively adopted FASB issued ASU No. 2015-13 “Derivatives and Hedging - Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets”, which allows certain forward contracts for physical delivery of electricity in nodal energy markets to qualify for the normal purchases and normal sales scope exception, as long as the physical delivery criterion and other criteria of the normal purchases and normal sales scope exception are met. The ASU applies to forward contracts in which one of the counterparties incurs location marginal pricing charges (or credits) payable to (or receivable from) an independent system operator. The adoption of this ASU did not have an impact on AltaGas’ consolidated financial statements.

**FUTURE CHANGES IN ACCOUNTING PRINCIPLES**

In May 2014, FASB issued an ASU No. 2014-09, "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. On July 9, 2015, FASB confirmed a one-year deferral of the new revenue standard. The new standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Early adoption prior to that date would not be permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In January 2015, FASB issued ASU No. 2015-01 “Income Statement – Extraordinary and Unusual Items” to eliminate the concept of extraordinary items and alleviate uncertainty for preparers, auditors and regulators because auditors and regulators no longer will need to evaluate whether a preparer treated an unusual and/or infrequent item appropriately. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In February 2015, FASB issued ASU No. 2015-02 “Consolidation: Amendments to Consolidation Analysis”. The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The amendments in this ASU are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In July 2015, FASB issued ASU No. 2015-11 “Inventory - Simplifying the Measurement of Inventory”. The amendment in this ASU requires an entity, to measure inventory at the lower of cost and net realizable value. The amendments in this ASU are effective for fiscal year, and interim periods within those fiscal years, beginning after December 15, 2016, prospectively. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In September 2015, FASB issued ASU No. 2015-16 “Business Combinations - Simplifying the Accounting for Measurement-Period Adjustments”. To simplify the accounting for adjustments made to provisional amounts recognized in a business combination, the amendments in this ASU eliminate the requirement to retrospectively account for those adjustments. Instead, an acquirer will recognize a measurement-period adjustment during the period in which the amount of the adjustment is determined. The amendments in this ASU are effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years, prospectively. AltaGas will apply this ASU prospectively to adjustments to provisional amounts that occur after the effective date of this ASU.

## 3. ACCUMULATED OTHER COMPREHENSIVE INCOME

| ($ millions) | Available-for -sale | Cash flow hedges | Defined benefit pension and PRB plans | Hedge net investments | Translation foreign operations | AOCI Investee | Total |
|---|---|---|---|---|---|---|---|
| **Opening balance, January 1, 2015** | **$ (12.0)** | **$ 13.3** | **$ (9.6)** | **$ (70.9)** | **$ 242.3** | **$ —** | **$ 163.1** |
| Other comprehensive income (OCI) before reclassification | **(15.9)** | **(0.4)** | **—** | **(64.8)** | **277.8** | **4.6** | **201.3** |
| Amounts reclassified from OCI | **—** | **(17.5)** | **1.3** | **—** | **—** | **—** | **(16.2)** |
| Current period other comprehensive income (loss) | **(15.9)** | **(17.9)** | **1.3** | **(64.8)** | **277.8** | **4.6** | **185.1** |
| Income tax on amounts retained in AOCI | **(0.1)** | **0.2** | **—** | **2.2** | **—** | **—** | **2.3** |
| Income tax on amounts reclassified to earnings | **—** | **4.4** | **(0.4)** | **—** | **—** | **—** | **4.0** |
| Net current period other comprehensive income (loss) | **(16.0)** | **(13.3)** | **0.9** | **(62.6)** | **277.8** | **4.6** | **191.4** |
| **Ending balance, September 30, 2015** | **$ (28.0)** | **$ —** | **$ (8.7)** | **$ (133.5)** | **$ 520.1** | **$ 4.6** | **$ 354.5** |
| Opening balance, January 1, 2014 | $ (3.0) | $ (10.4) | $ (5.7) | $ (35.9) | $ 94.5 | $ — | $ 39.5 |
| OCI before reclassification | 2.3 | 9.9 | 0.1 | (25.4) | 87.1 | — | 74.0 |
| Amounts reclassified from OCI | — | (0.1) | 0.3 | — | — | — | 0.2 |
| Current period other comprehensive income (loss) | 2.3 | 9.8 | 0.4 | (25.4) | 87.1 | — | 74.2 |
| Income tax on amounts retained in AOCI | (0.3) | (2.5) | — | 3.2 | — | — | 0.4 |
| Income tax on amounts reclassified to earnings | — | 0.1 | (0.2) | — | — | — | (0.1) |
| Net current period other comprehensive income (loss) | 2.0 | 7.4 | 0.2 | (22.2) | 87.1 | — | 74.5 |
| Ending balance, September 30, 2014 | $ (1.0) | $ (3.0) | $ (5.5) | $ (58.1) | $ 181.6 | $ — | $ 114.0 |

**Reclassification From Accumulated Other Comprehensive Income**

| AOCI components reclassified | Income Statement line item | **Three Months Ended September 30, 2015** | **Nine Months Ended September 30, 2015** |
|---|---|---|---|
| Cash flow hedges - commodity contracts | | | |
| Commodity contracts - NGL (realized effective portion) | Service revenue | **$ —** | **$ (7.2)** |
| Commodity contracts - NGL (discontinuation of hedge accounting)(1) | Unrealized gains on risk management contracts | **—** | **(10.3)** |
| Defined benefit pension plans | Operating and administrative expense | **0.5** | **1.3** |
| | Total before income taxes | **0.5** | **(16.2)** |
| Deferred income taxes | Income tax expenses – Deferred | **(0.1)** | **4.0** |
| | | **$ 0.4** | **$ (12.2)** |

(1) During the three and nine months ended September 2015, AltaGas discontinued cash flow hedge accounting on its existing NGL frac hedges as the forecasted NGL sales were no longer expected to occur.

| AOCI components reclassified | Income Statement line item | Three Months Ended September 30, 2014 | Nine Months Ended September 30, 2014 |
|---|---|---|---|
| Cash flow hedges - commodity contracts | | | |
| Commodity contracts - NGL (ineffective hedge) | Unrealized gains on risk management contracts | $ (1.3) | $ (0.4) |
| Bond forward | Interest expense – Long-term debt | — | 0.1 |
| | Other income (expenses) | — | 0.2 |
| Defined benefit pension plans | Operating and administrative expense | 0.1 | 0.3 |
| | Total before income taxes | (1.2) | 0.2 |
| Deferred income taxes | Income tax expenses – Deferred | 0.3 | (0.1) |
| | | $ (0.9) | $ 0.1 |

## 4. PROVISION ON LONG-LIVED ASSETS

In third quarter 2015, AltaGas recorded a pre-tax provision of $10.5 million related to the planned sale of certain development stage wind assets in northern California.

In first quarter 2014, AltaGas recorded a pre-tax provision of $19.6 million on its Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and an $18.7 million pre-tax provision for related Transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements. In addition, during the same quarter, AltaGas recorded a provision of $10.9 million related to certain hydro power assets under development in British Columbia.

## 5. BUSINESS ACQUISITION

On January 8, 2015 AltaGas completed the acquisition of three western U.S. natural gas-fired power assets with a total generation capacity of 164 MW for US$27.4 million before adjustments for working capital (the "Acquisition"). Transaction costs, such as legal, accounting, valuation and other professional fees related specifically to the Acquisition were US$0.8 million, before taxes, and were expensed in the Consolidated Statement of Income, within "Operating and administrative expenses". Below is a provisional purchase price allocation based on the Statement of Financial Position as at January 8, 2015, using an exchange rate of 1.1812 to convert US dollars to Canadian dollars.

| | | |
|---|---|---|
| Cash consideration | $ | 33.6 |
| Total consideration | $ | 33.6 |
| **Purchase price allocation** | | |
| Assets acquired: | | |
| Current assets | $ | 4.0 |
| Property, plant and equipment | | 23.2 |
| Intangible assets | | 9.2 |
| | $ | 36.4 |
| Liabilities assumed: | | |
| Current liabilities | $ | 2.8 |
| | $ | 33.6 |

## 6. INVENTORY

| As at | | **September 30, 2015** | | December 31, 2014 |
|---|---|---|---|---|
| Natural gas held in storage | **$** | **153.8** | $ | 136.7 |
| Other inventory | | **16.4** | | 18.6 |
| | **$** | **170.2** | $ | 155.3 |

## 7. GOODWILL

| As at | | **September 30, 2015** | | December 31, 2014 |
|---|---|---|---|---|
| Balance, beginning of period | **$** | **785.1** | $ | 743.1 |
| Foreign exchange translation | | **77.9** | | 42.0 |
| | **$** | **863.0** | $ | 785.1 |

## 8. LONG-TERM DEBT

| As at | Maturity date | | September 30, 2015 | | December 31, 2014 |
|---|---|---|---|---|---|
| Credit facilities | | | | | |
| $1,400 million unsecured extendible revolving[a] | 15-Dec-18 | **$** | **51.4** | $ | — |
| Medium-term notes (MTNs) | | | | | |
| $200 million Senior unsecured - 5.49 percent | 27-Mar-17 | | **200.0** | | 200.0 |
| $175 million Senior unsecured - 4.60 percent | 15-Jan-18 | | **175.0** | | 175.0 |
| $200 million Senior unsecured - 4.55 percent | 17-Jan-19 | | **200.0** | | 200.0 |
| $200 million Senior unsecured - 4.07 percent | 1-Jun-20 | | **200.0** | | 200.0 |
| $350 million Senior unsecured - 3.72 percent | 28-Sep-21 | | **350.0** | | 350.0 |
| $300 million Senior unsecured - 3.57 percent | 12-Jun-23 | | **300.0** | | 300.0 |
| $200 million Senior unsecured - 4.40 percent | 15-Mar-24 | | **200.0** | | 200.0 |
| $300 million Senior unsecured - 3.84 percent | 15-Jan-25 | | **299.9** | | 300.0 |
| $100 million Senior unsecured - 5.16 percent | 13-Jan-44 | | **100.0** | | 100.0 |
| $300 million Senior unsecured - 4.50 percent | 15-Aug-44 | | **299.8** | | 299.7 |
| US$175 million Senior unsecured - floating[b] | 13-Apr-15 | | **—** | | 203.0 |
| US$200 million Senior unsecured - floating[c] | 24-Mar-16 | | **267.9** | | 232.1 |
| US$125 million Senior unsecured - floating[d] | 17-Apr-17 | | **167.4** | | — |
| SEMCO long-term debt | | | | | |
| US$300 million SEMCO Senior secured - 5.15 percent[e] | 21-Apr-20 | | **401.8** | | 348.0 |
| US$82 million SEMCO Senior secured - 4.48 percent | 2-Mar-32 | | **103.6** | | 95.1 |
| Debenture notes | | | | | |
| PNG RoyNat Debenture - 3.275 percent[f] | 15-Sep-17 | | **8.9** | | 9.8 |
| PNG 2018 Series Debenture - 8.75 percent[f] | 15-Nov-18 | | **10.0** | | 10.0 |
| PNG 2024 CFI Debenture - 7.39 percent[g] | 1-Nov-24 | | **7.0** | | 7.4 |
| PNG 2025 Series Debenture - 9.30 percent[f] | 18-Jul-25 | | **14.0** | | 14.5 |
| PNG 2027 Series Debenture - 6.90 percent[f] | 2-Dec-27 | | **15.5** | | 15.5 |
| Loan from Province of Nova Scotia [h] | 31-Jul-17 | | **1.1** | | 2.1 |
| CINGSA capital lease - 3.50 percent | 1-May-40 | | **0.6** | | 0.5 |
| CINGSA capital lease - 4.48 percent | 4-Jun-68 | | **0.2** | | 0.2 |
| Promissory notes | 25-Oct-15 | | **0.5** | | 1.0 |
| Other long-term debt | | | **—** | | 0.1 |
| | | **$** | **3,374.6** | $ | 3,264.0 |
| Less debt issuance costs[i] | | | **(15.8)** | | (17.8) |
| | | | **3,358.8** | | 3,246.2 |
| Less current portion | | | **(279.3)** | | (214.4) |
| | | **$** | **3,079.5** | $ | 3,031.8 |

(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) The notes carried a floating rate coupon of three months LIBOR plus 0.79 percent.

(c) The notes carry a floating rate coupon of three months LIBOR plus 0.72 percent.

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

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

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

(g) Collateral for the Corpfinance International Ltd. (CFI) Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek, a first security interest over all the interests of PNG in partnership interests and shares of McNair Creek.

(h) The loan is non-interest bearing and, if certain prescribed revenue targets are achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. Heritage Gas may also elect to fully repay the loan at any time with no penalty.

(i) Effective July 1, 2015, AltaGas early adopted FASB issued ASU No. 2015-03. Please see note 2.

## 9. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation purchases and sells natural gas, NGL and power and issues short and long-term debt. The Corporation uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Corporation does not make use of derivative instruments for speculative purposes.

**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, interest rates 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, currency exchange and interest rate yield curves. 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, Short-term investments, Accounts Receivable, Accounts Payable, Short-term debt and Dividends Payable* - the carrying amounts approximate fair value because of the short maturity of these instruments.

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

*Risk management assets and liabilities* - the fair values of power, natural gas and NGL derivatives were calculated using discounted cash flow analysis based upon forward prices from published sources for the relevant period. The fair value of foreign exchange derivatives was calculated using quoted market rates.

| | September 30, 2015 | | | | |
|---|---|---|---|---|---|
| | **Carrying Amount** | **Level 1** | **Level 2** | **Level 3** | **Total Fair Value** |
| Financial assets | | | | | |
| Cash and cash equivalents | **$ 409.9** | **$ 409.9** | $ **—** | **$ —** | **$ 409.9** |
| Risk management assets - current | **30.6** | **—** | **30.6** | **—** | **30.6** |
| Risk management assets - non-current | **20.8** | **—** | **20.8** | **—** | **20.8** |
| Long-term investments and other assets [1] | **31.3** | **31.3** | **—** | **—** | **31.3** |
| | **$ 492.6** | **$ 441.2** | **$ 51.4** | **$ —** | **$ 492.6** |
| Financial liabilities | | | | | |
| Risk management liabilities - current | **$ 20.1** | **$ —** | **$ 20.1** | **$ —** | **$ 20.1** |
| Risk management liabilities - non-current | **14.8** | **—** | **14.8** | **—** | **14.8** |
| Current portion of long-term debt | **279.3** | **—** | **279.6** | **—** | **279.6** |
| Long-term debt | **3,079.5** | **—** | **3,199.3** | **—** | **3,199.3** |
| Other long-term liabilities [2] *(note 10)* | **149.5** | **—** | **139.2** | **—** | **139.2** |
| | **$ 3,543.2** | **$ —** | **$ 3,653.0** | **$ —** | **$ 3,653.0** |

| | December 31, 2014 | | | | |
|---|---|---|---|---|---|
| | Carrying Amount | Level 1 | Level 2 | Level 3 | Total Fair Value |
| Financial assets | | | | | |
| Cash and cash equivalents | $ 371.0 | $ 371.0 | $ — | $ — | $ 371.0 |
| Short-term investment | 50.0 | 50.0 | — | — | 50.0 |
| Risk management assets - current | 70.8 | — | 70.8 | — | 70.8 |
| Risk management assets - non-current | 21.1 | — | 21.1 | — | 21.1 |
| Long-term investments and other assets [1] | 46.3 | 46.3 | — | — | 46.3 |
| | $ 559.2 | $ 467.3 | $ 91.9 | $ — | $ 559.2 |
| Financial liabilities | | | | | |
| Risk management liabilities - current | $ 43.5 | $ — | $ 43.5 | — | $ 43.5 |
| Risk management liabilities - non-current | 14.7 | — | 14.7 | — | 14.7 |
| Current portion of long-term debt | 214.4 | — | 214.4 | — | 214.4 |
| Long-term debt | 3,031.8 | — | 3,170.3 | — | 3,170.3 |
| Other long-term liabilities [2] | 155.6 | — | 149.1 | — | 149.1 |
| | $ 3,460.0 | $ — | $ 3,592.0 | $ — | $ 3,592.0 |

[1] *Excludes non-financial assets and financial assets carried at cost.*

[2] *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, | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Natural gas | **$ 3.0** | $ 0.6 | **$ 6.0** | $ (0.5) |
| Storage optimization | **0.8** | (0.5) | **(0.1)** | 0.3 |
| NGL frac spread | **(5.9)** | 1.3 | **1.7** | 0.4 |
| Power | **12.4** | (0.2) | **(6.1)** | (1.7) |
| Heat rate | **0.7** | 0.2 | **(0.2)** | (0.1) |
| Foreign exchange | **(0.1)** | — | **0.3** | 0.1 |
| Embedded derivative | **(0.1)** | (0.3) | **—** | (0.2) |
| | **$ 10.8** | $ 1.1 | **$ 1.6** | $ (1.7) |

**Offsetting of Derivative Assets and Derivative Liabilities**

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

| | As at September 30, 2015 | | |
|---|---|---|---|
| Risk management assets [(1)] | **Gross amounts of recognized assets/liabilities** | **Gross amounts offset in balance sheet** | **Net amounts presented in balance sheet** |
| Natural gas | **$ 37.4** | **$ (12.7)** | **$ 24.7** |
| Storage optimization | **1.1** | **(0.2)** | **0.9** |
| NGL frac spread | **6.4** | **(1.4)** | **5.0** |
| Power | **21.6** | **(0.9)** | **20.7** |
| Heat rate | **0.1** | **—** | **0.1** |
| Foreign exchange | **2.6** | **(2.6)** | **—** |
| | **$ 69.2** | **$ (17.8)** | **$ 51.4** |
| Risk management liabilities [(2)] | | | |
| Natural gas | **$ 35.3** | **$ (12.7)** | **$ 22.6** |
| Storage optimization | **0.3** | **(0.2)** | **0.1** |
| NGL frac spread | **1.4** | **(1.4)** | **—** |
| Power | **12.9** | **(0.9)** | **12.0** |
| Foreign exchange | **2.8** | **(2.6)** | **0.2** |
| Total | **$ 52.7** | **$ (17.8)** | **$ 34.9** |

*(1) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $30.6 and risk management assets (non-current) balance of $20.8.*

*(2) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $20.1 and risk management liabilities (non-current) balance of $14.8.*

| | As at December 31, 2014 | | |
|---|---|---|---|
| Risk management assets [(1)] | Gross amounts of recognized assets/liabilities | Gross amounts offset in balance sheet | Net amounts presented in balance sheet |
| Natural gas | $ 61.0 | $ 25.2 | $ 35.8 |
| Storage optimization | 1.0 | — | 1.0 |
| NGL frac spread | 26.6 | — | 26.6 |
| Power | 28.0 | — | 28.0 |
| Heat rate | 0.5 | — | 0.5 |
| | $ 117.1 | $ 25.2 | $ 91.9 |
| Risk management liabilities [(2)] | | | |
| Natural gas | $ 64.9 | $ 25.2 | $ 39.7 |
| Storage optimization | 0.1 | — | 0.1 |
| NGL frac spread | 5.7 | — | 5.7 |
| Power | 12.1 | — | 12.1 |
| Heat rate | 0.1 | — | 0.1 |
| Foreign exchange | 0.5 | — | 0.5 |
| | $ 83.4 | $ 25.2 | $ 58.2 |

*(1) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $70.8 million and risk management assets (non-current) balance of $21.1 million.*

*(2) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $43.5 million and risk management liabilities (non-current) balance of $14.7 million.*

### Net Investment Hedge

As at September 30, 2015, AltaGas designated US$363.5 million of outstanding debt as a net investment hedge of its U.S. subsidiaries (December 31, 2014 - US$375 million). For the three and nine months ended September 30, 2015, AltaGas incurred after-tax unrealized loss of $32.9 million and $62.6 million, respectively, arising from the translation of debt in OCI (three and nine months ended September 30, 2014 - after-tax unrealized loss of $20.1 million and $22.2 million, respectively).

## 10. LONG-TERM LIABILITIES

In 2010, AltaGas entered into a 60-year CPI indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river project. As at December 31, 2013, AltaGas paid an initial consideration of $90.0 million in support of the construction and operation of the Northwest Transmission Line (NTL). On July 29, 2014, AltaGas paid $5.3 million to BC Hydro, and thereafter future consideration is expected to be approximately $9.8 million per year, adjusted for inflation. The NTL came into service on July 12, 2014, an event that triggered AltaGas' firm commitment with BC Hydro.

The fair value of the firm commitment on initial recognition was measured using an estimated 2 percent inflation rate and 4.27 percent discount rate. This fair value of the NTL liability has been recorded within other current liabilities for $11.0 million and other long-term liabilities for $149.5 million as at September 30, 2015. Accretion expenses for the three and nine months ended September 30, 2015 were $1.7 million and $5.2 million respectively (three and nine months ended September 30, 2014 - $1.0 million for both periods). The initial consideration and the fair value of the future considerations, for a total amount of $258.5 million, has been recognized within the intangible assets and depreciated over 60 years, the term of the EPA with BC Hydro.

## 11. 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.

On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

On September 30, 2015, 2,488,780 of the outstanding 8,000,000 Cumulative Redeemable Five Year Fixed Rate Reset Preferred Shares, Series A were converted into Cumulative Floating Rate Preferred Shares, Series B. The Series A preferred shares will continue to pay dividends on a quarterly basis, for the five-year period beginning on September 30, 2015, as and when declared by the Board of Directors of AltaGas, at an annual fixed dividend rate of 3.38 percent. The Series B preferred shares will pay a floating quarterly dividend for the five-year period beginning on September 30, 2015, as and when declared by the Board of Directors of AltaGas. The floating quarterly dividend rate for Series B preferred shares for the first quarterly floating rate period (being the period from September 30, 2015 to but excluding December 31, 2015) is 3.04 percent and will be reset every quarter at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill plus 2.66 percent.

| Common Shares Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 | 122,305,293 | $ | 2,211.4 |
| Shares issued for cash on exercise of options | 989,162 | | 24.9 |
| Shares issued on public offering | 9,027,500 | | 449.2 |
| Deferred taxes on share issuance cost | — | | 4.2 |
| Shares issued under DRIP | 1,619,794 | | 70.2 |
| December 31, 2014 | 133,941,749 | | 2,759.9 |
| Shares issued on public offering | 8,760,000 | | 288.0 |
| Shares issued for cash on exercise of options | 428,656 | | 11.8 |
| Deferred taxes on share issuance costs | — | | 3.1 |
| Shares issued under DRIP | 1,838,168 | | 68.5 |
| **Issued and outstanding at September 30, 2015** | **144,968,573** | **$** | **3,131.3** |

| Preferred Shares Series A Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 | 8,000,000 | $ | 194.1 |
| Deferred taxes on share issuance costs | — | | 1.8 |
| December 31, 2014 | 8,000,000 | | 195.9 |
| Shares converted to Series B | (2,488,780) | | (60.9) |
| **Issued and outstanding at September 30, 2015** | **5,511,220** | **$** | **135.0** |

| Preferred Shares Series B Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 and December 31, 2014 | — | $ | — |
| Shares issued on conversion from Series A | 2,488,780 | | 60.9 |
| **Issued and outstanding at September 30, 2015** | **2,488,780** | **$** | **60.9** |

| Preferred Shares Series C Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 | 8,000,000 | $ | 200.6 |
| December 31, 2014 | 8,000,000 | | 200.6 |
| **Issued and outstanding at September 30, 2015** | **8,000,000** | **$** | **200.6** |

| Preferred Shares Series E Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 | 8,000,000 | $ | 194.9 |
| Deferred taxes on share issuance costs | — | | 0.9 |
| December 31, 2014 | 8,000,000 | | 195.8 |
| **Issued and outstanding at September 30, 2015** | **8,000,000** | **$** | **195.8** |

| Preferred Shares Series G Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2014 | — | $ | — |
| Shares issued on public offering | 8,000,000 | | 200.0 |
| Share issuance costs, net of taxes | — | | (3.9) |
| December 31, 2014 | 8,000,000 | | 196.1 |
| **Issued and outstanding at September 30, 2015** | **8,000,000** | **$** | **196.1** |

### Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at September 30, 2015, 9,524,234 shares were reserved for issuance under the plan. As at September 30, 2015, options granted under the plan have a term between 6 and 10 years until expiry and vest no longer than over a four-year period.

As at September 30, 2015, unexpensed fair value of share option compensation cost associated with future periods was $3.4 million (December 31, 2014 - $5.2 million).

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

| | Options outstanding | |
|---|---|---|
| | Number of options | Exercise price[1] |
| Share options outstanding December 31, 2014 | 5,123,655 | $ 30.28 |
| Granted | 432,500 | 37.31 |
| Exercised | (428,656) | 25.06 |
| Expired | (4,500) | 38.63 |
| Forfeited | (150,376) | 35.10 |
| **Share options outstanding September 30, 2015** | **4,972,623** | **$ 31.20** |
| **Share options exercisable September 30, 2015** | **2,842,561** | **$ 26.15** |

(1) *Weighted average.*

The following table summarizes the employee share option plan as at September 30, 2015:

| | Options outstanding | | | Options exercisable | |
|---|---|---|---|---|---|
| | Number outstanding | Weighted average exercise price | Weighted average remaining contractual life | Number exercisable | Weighted average exercise price |
| $14.24 to $18.00 | 263,000 | $ 15.14 | 3.53 | 263,000 | $ 15.14 |
| $18.01 to $25.08 | 955,550 | 20.71 | 4.58 | 955,550 | 20.71 |
| $25.09 to $50.89 | 3,754,073 | 34.99 | 5.64 | 1,624,011 | 31.13 |
| | **4,972,623** | **$ 31.20** | **5.32** | **2,842,561** | **$ 26.15** |

**Mid-Term Incentive Plan (MTIP)**

AltaGas' MTIP for employees and executive officers includes two types of awards: restricted units (RUs) and performance units (PUs). Both RUs and PUs have vesting periods between 36 to 44 months from the grant date. Both RUs and PUs are valued based on the dividends declared during the vesting period and the weighted average share price of AltaGas' common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RUs and PUs are paid in cash or at the election of AltaGas, its equivalent in common shares purchased from the market. The PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets agreed between the Corporation and the employees.

For the three and nine months ended September 30, 2015, the compensation expense recorded for the MTIP was $0.2 million and $2.5 million, respectively (three months and nine months ended September 30, 2014 - $1.2 million and $4.0 million, respectively). As at September 30, 2015, the unrecognized compensation expense relating to the remaining vesting period was $12.7 million (December 31, 2014 - $11.7 million).

## 12. NET INCOME PER COMMON SHARES

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

| | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Numerator: | | | | |
| Net income applicable to controlling interests | **$ 30.1** | $ 26.4 | **$ 94.7** | $ 110.0 |
| Less: Preferred share dividends | **(10.3)** | (9.8) | **(30.5)** | (24.6) |
| Net income per common shares | **$ 19.8** | $ 16.6 | **$ 64.2** | $ 85.4 |
| Denominator: | | | | |
| *(millions)* | | | | |
| Weighted average number of common shares outstanding | **135.8** | 127.1 | **135.0** | 124.3 |
| Dilutive equity instruments[1] | **0.8** | 2.1 | **1.2** | 2.0 |
| Weighted average number of common shares outstanding - diluted | **136.6** | 129.2 | **136.2** | 126.3 |
| Basic net income per common share | **$ 0.15** | $ 0.13 | **$ 0.48** | $ 0.69 |
| Diluted net income per common share | **$ 0.14** | $ 0.13 | **$ 0.47** | $ 0.68 |

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at September 30, 2015 and 2014.*

For the three and nine months ended September 30, 2015, 1.7 million and 1.6 million of share options, (three and nine months ended September 30, 2014 - 0.1 million for both periods) respectively were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

## 13. COMMITMENTS AND CONTINGENCIES

**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 2015 to 2019, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines at the Blythe facility over 116,000 EOH/CT, or 20 years, whichever comes first, in exchange for $224.1 million payable over the next 19 years, of which $54.4 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 southwest Ontario. AltaGas is obligated to pay approximately $3.4 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 $11.7 million over the next 7 years, of which $8.4 million is payable in the next five years.

On September 21, 2015, AltaGas and its indirect wholly-owned subsidiary AltaGas Power Holdings (U.S.) Inc., entered into a purchase and sale agreement to acquire GWF Energy Holdings LLC, which holds a portfolio of three natural gas-fired electrical generation facilities in northern California totaling 523 MW, for US$642 million, excluding customary closing adjustments. The transaction is expected to close in fourth quarter 2015.

**Guarantees**

On October 2014, Heritage Gas Limited, a wholly-owned subsidiary of AltaGas, entered into a throughput contract with a third party owner of the transportation facility for the use of their pipelines in the U.S. and Canada. The contract will commence at completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas issued a US $91.7 million guarantee to stand by all payment obligations under the transportation agreement.

**Contingencies**

AltaGas is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators. On January 20, 2015, the AUC released a decision concerning the complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology used for the power distribution in Alberta. The AUC will proceed to determine the relief and remedies to be granted in accordance with its findings and conclusions regarding its authority and jurisdiction made in its decision. AltaGas is one of the respondents to the complaint and it has assessed that it may incur additional payments for transmission charges, but the timing and amount, or range of amounts, required to settle the claim cannot be estimated and, accordingly, no accrual of the loss contingency was recognized as at September 30, 2015.

## 14. 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, 2015** | | | | | |
|---|---|---|---|---|---|---|
| | **Canada** | | **United States** | | **Total** | |
| | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** |
| Current service cost | $ 1.7 | $ 0.2 | $ 2.0 | $ 0.5 | $ 3.7 | $ 0.7 |
| Interest cost | 1.3 | 0.1 | 2.7 | 0.9 | 4.0 | 1.0 |
| Expected return on plan assets | (1.3) | — | (3.8) | (1.2) | (5.1) | (1.2) |
| Amortization of net actuarial loss | 0.5 | — | — | — | 0.5 | — |
| Amortization of regulatory asset | 0.4 | — | 1.1 | 0.2 | 1.5 | 0.2 |
| Net benefit cost recognized | $ 2.6 | $ 0.3 | $ 2.0 | $ 0.4 | $ 4.6 | $ 0.7 |

| | **Nine Months Ended September 30, 2015** | | | | | |
|---|---|---|---|---|---|---|
| | **Canada** | | **United States** | | **Total** | |
| | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** |
| Current service cost | $ 5.2 | $ 0.5 | $ 5.7 | $ 1.5 | $ 10.9 | $ 2.0 |
| Interest cost | 3.9 | 0.4 | 7.8 | 2.6 | 11.7 | 3.0 |
| Expected return on plan assets | (3.8) | (0.1) | (10.9) | (3.4) | (14.7) | (3.5) |
| Amortization of net actuarial loss | 1.5 | — | — | — | 1.5 | — |
| Amortization of regulatory asset | 1.1 | 0.1 | 3.2 | 0.5 | 4.3 | 0.6 |
| Net benefit cost recognized | $ 7.9 | $ 0.9 | $ 5.8 | $ 1.2 | $ 13.7 | $ 2.1 |

| | Three Months Ended September 30, 2014 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | | United States | | Total | |
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 1.4 | $ 0.1 | $ 1.4 | $ 0.3 | $ 2.8 | $ 0.4 |
| Interest cost | 1.3 | 0.1 | 2.3 | 0.8 | 3.6 | 0.9 |
| Expected return on plan assets | (1.2) | — | (3.0) | (1.0) | (4.2) | (1.0) |
| Amortization of past service cost | — | — | — | (0.1) | — | (0.1) |
| Amortization of net actuarial loss | 0.1 | — | 0.2 | 0.1 | 0.3 | 0.1 |
| Amortization of regulatory asset | 0.2 | — | 0.5 | 0.1 | 0.7 | 0.1 |
| Net benefit cost recognized | $ 1.8 | $ 0.2 | $ 1.4 | $ 0.2 | $ 3.2 | $ 0.4 |

| | Nine Months Ended September 30, 2014 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | | United States | | Total | |
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 4.3 | $ 0.4 | $ 4.1 | $ 1.0 | $ 8.4 | $ 1.4 |
| Interest cost | 3.9 | 0.4 | 6.9 | 2.3 | 10.8 | 2.7 |
| Expected return on plan assets | (3.5) | (0.1) | (9.1) | (2.9) | (12.6) | (3.0) |
| Amortization of past service cost | 0.1 | — | — | (0.2) | 0.1 | (0.2) |
| Amortization of net actuarial loss | 0.4 | — | 0.6 | 0.2 | 1.0 | 0.2 |
| Amortization of regulatory asset | 0.6 | — | 1.4 | 0.3 | 2.0 | 0.3 |
| Net benefit cost recognized | $ 5.8 | $ 0.7 | $ 3.9 | $ 0.7 | $ 9.7 | $ 1.4 |

## 15. INCOME TAX EXPENSE

Effective July 1, 2015, the Alberta corporate tax rate increased from 10 percent to 12 percent. As a result of the revaluation of the deferred income tax liabilities using the increased tax rate, AltaGas recognized an additional $14 million of deferred income tax expense for the nine months ended September 30, 2015 (2014 - $nil). Including the effects of the tax rate increase, the total deferred income tax expense recognized by AltaGas for the three and nine months ended September 30, 2015 was $2.4 million and $27.7 million, respectively (three and nine months ended September 30, 2014 - $3.2 million and $11.8 million, respectively).

## 16. SUPPLEMNTAL 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, | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Accounts receivable | $ **(5.4)** | **$** (1.7) | $ **143.8** | **$** 151.3 |
| Inventory | **(43.5)** | (58.1) | **7.4** | (38.6) |
| Other current assets | **(23.8)** | (6.1) | **(9.5)** | 4.7 |
| Regulatory assets (current) | **3.5** | 4.0 | **12.4** | (29.9) |
| Accounts payable and accrued liabilities | **18.8** | 31.6 | **(38.1)** | (43.1) |
| Customer deposits | **11.7** | 12.6 | **(1.3)** | (2.2) |
| Regulatory liabilities (current) | **(1.8)** | 1.0 | **6.3** | (0.3) |
| Other current liabilities | **5.6** | 1.6 | **(6.2)** | (5.3) |
| Other operating assets and liabilities | **(6.9)** | 8.6 | **(14.0)** | 5.5 |
| | $ **(41.8)** | $ (6.5) | $ **100.8** | $ 42.1 |

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Interest paid (net of capitalized interest) | **$ 51.4** | $ 29.9 | **$ 110.3** | $ 73.6 |
| Income taxes paid | **$ 1.1** | $ 2.5 | **$ 14.8** | $ 14.4 |

## 17. 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 strong first and fourth quarter results and weaker second and third quarters.

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

## 18. 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;<br>– transmission pipelines to transport natural gas and NGL;<br>– natural gas gathering lines and field processing facilities;<br>– purchase and sale of natural gas, including to commercial and industrial users;<br>– natural gas storage facilities;<br>– LNG and LPG development projects; and<br>– equity investments in a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents. |
| **Power** | – coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase agreements, both operational and under construction; and<br>– 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<br>– rate-regulated natural gas storage in Michigan and Alaska. |
| **Corporate** | – the cost of providing corporate services, financing and general corporate overhead, investments in 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, 2015** | | | | | |
|---|---|---|---|---|---|---|
| | **Gas** | **Power** | **Utilities** | **Corporate** | **Intersegment Elimination[1]** | **Total** |
| Revenue | $ 180.6 | $ 130.5 | $ 145.4 | $ — | $ (15.1) | $ 441.4 |
| Unrealized gain on risk management | — | — | — | 10.8 | — | 10.8 |
| Cost of sales | (90.1) | (45.1) | (58.4) | — | 13.7 | (179.9) |
| Operating and administrative | (51.2) | (18.4) | (56.3) | (10.0) | 1.8 | (134.1) |
| Accretion expenses | (0.9) | (1.8) | — | — | — | (2.7) |
| Depreciation and amortization | (16.1) | (15.0) | (19.1) | (2.7) | — | (52.9) |
| Impairment of assets | — | (10.5) | — | — | — | (10.5) |
| Income (loss) from equity investments | 3.0 | (8.5) | 0.5 | — | — | (5.0) |
| Other income | — | — | 0.9 | 0.6 | (0.4) | 1.1 |
| Foreign exchange loss | — | — | — | — | — | — |
| Interest expense | — | — | — | (31.4) | — | (31.4) |
| Income (loss) before income taxes | $ 25.3 | $ 31.2 | $ 13.0 | $ (32.7) | $ — | $ 36.8 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 53.0 | $ 54.1 | $ 54.4 | $ 2.9 | $ — | $ 164.4 |
| Intangible assets | $ 0.4 | $ 10.9 | $ 1.0 | $ 1.5 | $ — | $ 13.8 |

| | Nine months ended September 30, 2015 | | | | | |
|---|---|---|---|---|---|---|
| | **Gas** | **Power** | **Utilities** | **Corporate** | **Intersegment Elimination**[1] | **Total** |
| Revenue | **$ 642.8** | **$ 344.9** | **$ 756.1** | **$ —** | **$ (132.5)** | **$ 1,611.3** |
| Unrealized gain on risk management | **—** | **—** | **—** | **1.6** | **—** | **1.6** |
| Cost of sales | **(381.9)** | **(162.3)** | **(416.4)** | **—** | **128.2** | **(832.4)** |
| Operating and administrative | **(137.5)** | **(50.3)** | **(166.7)** | **(22.4)** | **4.7** | **(372.2)** |
| Accretion expenses | **(2.8)** | **(5.4)** | **—** | **—** | **—** | **(8.2)** |
| Depreciation and amortization | **(46.6)** | **(44.0)** | **(55.9)** | **(6.0)** | **—** | **(152.5)** |
| Impairment of assets | **—** | **(10.5)** | **—** | **—** | **—** | **(10.5)** |
| Income (loss) from equity investments | **1.3** | **(8.1)** | **1.4** | **—** | **—** | **(5.4)** |
| Other income | **—** | **—** | **2.4** | **3.3** | **(0.4)** | **5.3** |
| Foreign exchange gain | **—** | **—** | **—** | **0.4** | **—** | **0.4** |
| Interest expense | **—** | **—** | **—** | **(91.6)** | **—** | **(91.6)** |
| Income (loss) before income taxes | **$ 75.3** | **$ 64.3** | **$ 120.9** | **$ (114.7)** | **$ —** | **$ 145.8** |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | **$ 124.1** | **$ 163.4** | **$ 124.8** | **$ 4.7** | **$ —** | **$ 417.0** |
| Intangible assets | **$ 1.5** | **$ 20.2** | **$ 2.1** | **$ 11.5** | **$ —** | **$ 35.3** |

(1) *Intersegment transactions are recorded at market value.*

(2) *Net additions to property, plant and equipment and intangible assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

| | Three months ended September 30, 2014 | | | | | |
|---|---|---|---|---|---|---|
| | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
| Revenue | $ 235.7 | $ 102.3 | $ 132.2 | $ — | $ (27.1) | $ 443.1 |
| Unrealized gain on risk management | — | — | — | 1.1 | — | 1.1 |
| Cost of sales | (139.0) | (66.7) | (60.8) | — | 25.1 | (241.4) |
| Operating and administrative | (46.8) | (12.3) | (48.9) | (6.5) | 2.0 | (112.5) |
| Accretion expenses | (0.9) | (1.1) | — | — | — | (2.0) |
| Depreciation and amortization | (16.6) | (10.4) | (15.8) | (0.8) | — | (43.6) |
| Income from equity investments | 6.0 | 7.4 | — | — | — | 13.4 |
| Other income (loss) | (0.1) | 0.1 | 1.0 | 0.2 | — | 1.2 |
| Foreign exchange loss | — | — | — | (0.5) | — | (0.5) |
| Interest expense | — | — | — | (28.6) | — | (28.6) |
| Income (loss) before income taxes | $ 38.3 | $ 19.3 | $ 7.7 | $ (35.1) | $ — | $ 30.2 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 25.6 | $ 59.9 | $ 49.5 | $ 0.7 | $ — | $ 135.7 |
| Intangible assets | $ 0.1 | $ 5.3 | $ — | $ 5.3 | $ — | $ 10.7 |

| | Nine months ended September 30, 2014 | | | | | |
|---|---|---|---|---|---|---|
| | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
| Revenue | $ 887.2 | $ 283.6 | $ 748.9 | $ — | $ (178.8) | $ 1,740.9 |
| Unrealized loss on risk management | — | — | — | (1.7) | — | (1.7) |
| Cost of sales | (591.3) | (189.7) | (447.5) | — | 172.6 | (1,055.9) |
| Operating and administrative | (137.9) | (35.9) | (147.9) | (20.8) | 6.2 | (336.3) |
| Accretion expenses | (2.8) | (1.2) | (0.1) | — | — | (4.1) |
| Depreciation and amortization | (50.2) | (26.5) | (47.7) | (2.2) | — | (126.6) |
| Provision on long-lived assets | (38.3) | (10.9) | — | — | — | (49.2) |
| Income from equity investments | 19.3 | 17.9 | 0.8 | — | — | 38.0 |
| Other income (loss) | 12.0 | (0.1) | 2.4 | (1.7) | — | 12.6 |
| Foreign exchange loss | — | — | — | (0.3) | — | (0.3) |
| Interest expense | — | — | — | (76.9) | — | (76.9) |
| Income (loss) before income taxes | $ 98.0 | $ 37.2 | $ 108.9 | $ (103.6) | $ — | $ 140.5 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 20.1 | $ 227.0 | $ 108.1 | $ 3.4 | $ — | $ 358.6 |
| Intangible assets | $ 0.3 | $ 5.3 | $ 0.7 | $ 12.6 | $ — | $ 18.9 |

(1) *Intersegment transactions are recorded at market value.*

(2) *Net additions to property, plant and equipment and intangible assets may not agree to changes reflected in Consolidated Balance Sheets 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, 2015** | | | | | |
| Goodwill | **$ 161.4** | **$ —** | **$ 701.6** | **$ —** | **$ 863.0** |
| Segmented assets | **$ 2,377.7** | **$ 2,619.4** | **$ 3,346.2** | **$ 615.9** | **$ 8,959.2** |
| As at December 31, 2014 | | | | | |
| Goodwill | $ 161.4 | $ — | $ 623.7 | $ — | $ 785.1 |
| Segmented assets | $ 2,284.3 | $ 2,338.1 | $ 3,142.5 | $ 630.7 | $ 8,395.6 |

# Supplementary Quarterly Financial Information

(unaudited)

**FINANCIAL HIGHLIGHTS**[1]

| *($ millions unless otherwise indicated)* | **Q3-15** | Q2-15 | Q1-15 | Q4-14 | Q3-14 |
|---|---|---|---|---|---|
| Net Revenue[2] | | | | | |
| Gas | **$ 93.5** | $ 80.4 | $ 88.3 | $ 97.5 | $ 102.6 |
| Power | **76.9** | 52.2 | 45.3 | 72.7 | 43.0 |
| Utilities | **88.4** | 94.3 | 160.9 | 125.2 | 72.5 |
| Corporate | **11.4** | (21.3) | 14.7 | (8.7) | 1.3 |
| Intersegment Elimination | **(1.8)** | (1.1) | (1.8) | (1.6) | (2.0) |
| | **$ 268.4** | $ 204.5 | $ 307.4 | $ 285.1 | $ 217.4 |
| Normalized EBITDA[2] | | | | | |
| Gas | **$ 43.3** | $ 37.4 | 46.9 | 58.4 | 56.5 |
| Power | **58.7** | 34.3 | 31.6 | 30.2 | 30.9 |
| Utilities | **32.0** | 40.5 | 104.4 | 73.9 | 23.6 |
| Corporate | **(9.5)** | (5.7) | (5.3) | (7.7) | (6.1) |
| | **$ 124.5** | $ 106.5 | $ 177.6 | $ 154.8 | $ 104.9 |
| Normalized Operating Income (Loss)[2] | | | | | |
| Gas | **$ 26.3** | $ 21.2 | $ 30.8 | $ 40.8 | $ 39.0 |
| Power | **42.0** | 18.0 | 15.2 | 16.0 | 19.4 |
| Utilities | **12.8** | 22.2 | 85.9 | 57.2 | 7.8 |
| Corporate | **(12.3)** | (7.4) | (6.9) | (8.9) | (6.9) |
| | **$ 68.8** | $ 54.0 | $ 125.0 | $ 105.1 | $ 59.3 |

(1) *Columns may not add due to rounding.*

(2) *Non-GAAP financial measure.*

# Supplementary Quarterly Operating Information

(unaudited)

| | **Q3-15** | Q2-15 | Q1-15 | Q4-14 | Q3-14 |
|---|---|---|---|---|---|
| **OPERATING HIGHLIGHTS** | | | | | |
| **GAS** | | | | | |
| Total inlet gas processed (Mmcf/d)(1) | **1,293** | 1,123 | 1,498 | 1,551 | 1,447 |
| Extraction volumes (Bbls/d)(1) (2) | **30,241** | 49,288 | 73,293 | 76,203 | 72,969 |
| Frac spread - realized ($/Bbl)(1) (3) | **34.58** | 20.58 | 11.43 | 16.29 | 14.19 |
| Frac spread - average spot price ($/Bbl)(1)(4) | **11.11** | 2.51 | 3.72 | 11.18 | 16.58 |
| **POWER** | | | | | |
| Volume of power sold (GWh)(1) | **1,697** | 1,287 | 1,449 | 1,457 | 1,464 |
| Average Alberta realized power price ($/MWh)(1) | **38.80** | 48.16 | 45.42 | 48.85 | 67.69 |
| Average price realized on sale of power ($/MWh)(1) (5) | **72.89** | 68.18 | 54.62 | 63.77 | 74.51 |
| Alberta Power Pool average spot price ($/MWh)(1) | **26.09** | 57.22 | 29.02 | 30.47 | 64.34 |
| **UTILITIES** | | | | | |
| Canadian utilities | | | | | |
| Natural gas deliveries - end-use (PJ)(6) | **3.3** | 5.2 | 13.0 | 10.6 | 3.1 |
| Natural gas deliveries - transportation (PJ)(6) | **1.6** | 1.5 | 1.9 | 1.4 | 1.0 |
| U.S. utilities | | | | | |
| Natural gas deliveries end use (Bcf) (6) | **5.9** | 10.0 | 32.1 | 23.1 | 6.1 |
| Natural gas deliveries transportation (Bcf) (6) | **10.5** | 10.0 | 13.7 | 11.7 | 8.5 |
| Service sites(7) | **562,301** | 560,755 | 564,173 | 562,746 | 554,837 |
| Degree day variance from normal - AUI (%)(8) | **3.9** | (9.7) | (11.3) | (3.1) | (6.2) |
| Degree day variance from normal - Heritage Gas (%)(8) | **(42.0)** | 14.7 | 15.7 | (8.4) | (1.5) |
| Degree day variance from normal - SEMCO Gas (%)(9) | **(28.4)** | (1.7) | 16.4 | 5.1 | 44.7 |
| Degree day variance from normal - ENSTAR (%)(9) | **(9.6)** | (17.4) | (8.0) | (10.5) | (8.3) |

*(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, divided by the respective frac exposed volumes for the period.*

*(5) Price received excludes Blythe as it earns fixed capacity payments under its PPA with SCE.*

*(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 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 |
| kV | kilovolt |
| Mcf | thousand cubic feet |
| Mmcf/d | million cubic feet per day |
| mtpa/ | metric tonnes per annum |
| MW | megawatt |
| MWh/ | megawatt-hour |
| PJ | petajoule |
| MMBTU | million British thermal unit |

**ABOUT ALTAGAS**

AltaGas is an energy infrastructure business 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 renewable energy sources. For more information visit: www.altagas.ca.

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