AltaGas

# NEWS RELEASE
# ALTAGAS LTD. REPORTS SECOND QUARTER RESULTS; ADVANCES ITS NORTHEAST BC PROJECTS AND LPG EXPORTS OFF CANADA'S WEST COAST

**Calgary, Alberta (July 30, 2015)**

**Highlights**

- $1 billion investment in energy infrastructure in British Columbia over the next two years;
- Began construction of $350 million Townsend gas facility;
- Exclusivity agreement for LPG export site in British Columbia;
- Development process underway for liquids hub in Fort St John;
- Better than expected results from Forrest Kerr and Volcano Creek;
- Regulatory approval of Main Replacement Program at SEMCO resulting in increased rate base growth; and
- $107 million in normalized EBITDA.

AltaGas Ltd. ("AltaGas") (TSX:ALA) today reported second quarter normalized EBITDA of $107 million, the same as in second quarter 2014. Normalized funds from operations were $68 million ($0.50 per share) for the second quarter 2015.

"With a stronger second half to 2015 we expect to deliver 10 to 15 percent year-over-year EBITDA growth," said David Cornhill, Chairman and CEO of AltaGas. "We continue to drive near-term growth. We significantly ramped up LPG exports, Forrest Kerr and Volcano Creek are performing better than expected and McLymont will be in service shortly. We are now in the construction phase at Townsend and expect to have it in operation in mid-2016."

AltaGas continues to develop new markets for natural gas liquids as it expands its LPG export capabilities. In addition to expanding LPG export capability at the Ferndale facility located in the State of Washington and owned by Petrogas, AltaGas has entered into an exclusivity agreement to develop an LPG export site in British Columbia. The initial phase of this export facility is expected to ship 25,000 Bbls/d, with significant expansion opportunities.

LPG supply for the proposed export facility in British Columbia is expected to be sourced from AltaGas' natural gas processing infrastructure, as well as through Petrogas' logistics network. 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 FEED study is in progress and is expected to be completed by the end of 2015. Consultations with key stakeholders are commencing and the regulatory permitting process will begin shortly. AltaGas expects to make a final investment decision in 2016.

AltaGas is already processing natural gas from the Montney region at its Younger, Blair Creek and Gordondale facilities which are operating at close to full capacity. Additional processing capacity will be added with its new 198Mmcf/d Townsend shallow-cut processing facility. AltaGas has started construction and approximately $100 million of equipment and services have been procured for the project-to-date. The facility is scheduled to be in service by mid-2016.

On the LNG export front, AltaGas along with the other members of the Douglas Channel LNG consortium continue to develop the 0.55 million tonnes per annum project at Kitimat. Producer discussions to supply the project, as well as technical and permitting work, are ongoing. A final investment decision is expected in fourth quarter 2015.

During the quarter, SEMCO's Main Replacement Program application was approved by the Michigan Public Service Commission. The approval allows for the recovery of capital expenditures from 2016 to 2020. The new rates took effect immediately and are expected to result in approximately US$3 million of additional earnings on an annualized basis.

In second quarter 2015, EBITDA was driven by the addition in late 2014 of the Forrest Kerr and Volcano Creek hydroelectric power generation facilities, new US gas-fired power assets acquired in first quarter 2015 and favourable foreign exchange rates. Overall, EBITDA held flat as EBITDA growth was offset by the impact of historically low commodity prices as well as the planned turnarounds at Younger and Harmattan.

Normalized funds from operations were $68 million ($0.50 per share) for the second quarter 2015, compared to $106 million ($0.86 per share) in the same period 2014. Funds from operations decreased primarily due to $28 million dividend received from Petrogas in second quarter 2014 compared to nil in second quarter 2015 and higher interest expense as a result of new assets being placed into service. 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 was $9 million ($0.07 per share), compared to $27 million ($0.22 per share) in second quarter 2014. Higher depreciation and higher financing costs partially offset by lower normalized income tax expense resulted in lower net income.

On a GAAP basis, AltaGas reported a net loss applicable to common shares of $22 million ($0.16 per share) in second quarter 2015, compared to net income of $29 million ($0.23 per share) for the same period 2014. The net loss was primarily the result of the recent increase in Alberta's corporate tax rate which impacted net income by $14 million, ($0.10 per share), and unrealized after tax losses of $17 million related primarily to Alberta power hedges.

For the six months ended June 30, 2015, normalized EBITDA was $284 million compared to $287 million for the same period in 2014. Normalized funds from operations were $208 million ($1.54 per share), compared to $238 million ($1.93 per share) for same period 2014. The decrease was primarily due to the discretionary timing of dividend payments from Petrogas. Excluding the impact of the dividends received from Petrogas, normalized funds from operations were $208 million for six months ended 2015, compared to $210 million for the same period 2014.

Normalized net income for six months ended June 30, 2015, was $66 million ($0.49 per share), compared to $101 million ($0.82 per share) for the same period 2014. On a GAAP basis, net income applicable to common shares was $44 million ($0.33 per share) for six months ended June 30, 2015, compared to $69 million ($0.56 per share) for the same period 2014. Net income for six months ended June 30, 2015 was primarily impacted by the recent increase in Alberta's corporate tax rate and by unrealized losses on Alberta power hedges. Net income applicable to common shares for the six months ended June 30, 2014 includes an after-tax gain of $9 million from the sale of assets, offset by a non-cash after-tax provision of $29 million related to assets from the acquisition of Taylor NGL Limited Partnership in 2008, a non-cash after tax provision of $8 million related to a number of small hydro power assets under development, mark-to-market accounting and the cost of early redemption of medium-term notes.

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

- The Board of Directors approved the August 2015 dividend of $0.16 per common share. The dividend will be paid on September 15, 2015, to common shareholders of record on August 25, 2015. The ex-dividend date is August 21, 2015. This dividend is eligible for Canadian income tax purposes.
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing July 1, 2015 and ending September 30, 2015, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on September 30, 2015 to shareholders of record on September 16, 2015. The ex-dividend date is September 14, 2015;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing July 1, 2015 and ending September 30, 2015, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on September 30, 2015 to shareholders of record on September 16, 2015. The ex-dividend date is September 14, 2015;
- The Board of Directors also approved a dividend of $0.3125 per share for the period commencing July 1, 2015, and ending September 30, 2015, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on September 30, 2015 to shareholders of record on September 16, 2015. The ex-dividend date is September 14, 2015; and
- The Board of Directors also approved a dividend of $0.296875 per share for the period commencing July 1, 2015, and ending September 30, 2015, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on September 30, 2015 to shareholders of record on September 16, 2015. The ex-dividend date is September 14, 2015.

**CONSOLIDATED FINANCIAL REVIEW**

| *(unaudited)* *($ millions)* | Three months ended June 30 **2015** | 2014 | Six months ended June 30 **2015** | 2014 |
|---|---|---|---|---|
| Revenue | **416** | 471 | **1,161** | 1,295 |
| Net revenue(1) | **204** | 220 | **512** | 516 |
| Normalized operating income(1) | **54** | 64 | **179** | 202 |
| Normalized EBITDA(1) | **107** | 107 | **284** | 287 |
| Net income (loss) applicable to common shares | **(22)** | 29 | **44** | 69 |
| Normalized net income(1) | **9** | 27 | **66** | 101 |
| Total assets | **8,495** | 7,197 | **8,495** | 7,197 |
| Total long-term liabilities | **4,155** | 3,800 | **4,155** | 3,800 |
| Net additions to property, plant and equipment | **143** | 132 | **253** | 220 |
| Dividends declared(2) | **63** | 52 | **123** | 99 |
| Cash flows | | | | |
| Normalized funds from operations(1) | **68** | 106 | **208** | 238 |

| *($ per share, except shares outstanding)* | Three months ended June 30 **2015** | 2014 | Six months ended June 30 **2015** | 2014 |
|---|---|---|---|---|
| Normalized EBITDA(1) | **0.79** | 0.87 | **2.10** | 2.33 |
| Net income (loss) per common shares - basic | **(0.16)** | 0.23 | **0.33** | 0.56 |
| Net income (loss) per common shares - diluted | **(0.16)** | 0.23 | **0.33** | 0.55 |
| Normalized net income(1) | **0.07** | 0.22 | **0.49** | 0.82 |
| Dividends declared(2) | **0.47** | 0.42 | **0.91** | 0.81 |
| Cash flows | | | | |
| Normalized funds from operations(1) | **0.50** | 0.86 | **1.54** | 1.93 |
| Shares outstanding - basic (millions) | | | | |
| During the period(3) | **135** | 123 | **135** | 123 |
| End of period | **135** | 124 | **135** | 124 |

(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 second 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 7005138. The replay expires at midnight (Eastern) on August 6, 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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# 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 six months ended June 30, 2015, compared to the three and six months ended June 30, 2014. This MD&A dated July 30, 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 six months ended June 30, 2015, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2014.*

*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, expected growth, results of operations, 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, 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., and AltaGas Services (US) Inc.

## SECOND QUARTER HIGHLIGHTS [1]

- Normalized funds from operations was $68 million, compared to $106 million in second quarter 2014;
- Normalized funds from operations excluding Petrogas dividend was $78 million in second quarter 2014;
- Normalized EBITDA was $107 million, same as second quarter 2014;
- Net revenue was $204 million, compared to $220 million in second quarter 2014;
- Began construction of $350 million Townsend gas facility;
- Better than expected results from Forrest Kerr and Volcano Creek;
- Regulatory approval of Main Replacement Program at SEMCO;
- Net debt was $3.0 billion as at June 30, 2015, compared to $3.2 billion as at June 30, 2014, and $2.9 billion as at December 31, 2014; and
- Debt-to-total capitalization ratio was 45 percent as at June 30, 2015, compared to 53 percent as at June 30, 2014, and 45 percent as at December 31, 2014.

(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 | **143** | 132 | **253** | 220 |
| Dividends declared[2] | **63** | 52 | **123** | 99 |
| Cash flows | | | | |
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| Normalized EBITDA[1] | **0.79** | 0.87 | **2.10** | 2.33 |
| Net income (loss) per common shares - basic | **(0.16)** | 0.23 | **0.33** | 0.56 |
| Net income (loss) per common shares - diluted | **(0.16)** | 0.23 | **0.33** | 0.55 |
| Normalized net income[1] | **0.07** | 0.22 | **0.49** | 0.82 |
| Dividends declared[2] | **0.47** | 0.42 | **0.91** | 0.81 |
| Cash flows | | | | |
| Normalized funds from operations[1] | **0.50** | 0.86 | **1.54** | 1.93 |
| Shares outstanding - basic (millions) | | | | |
| During the period[3] | **135** | 123 | **135** | 123 |
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(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.*

**Three Months Ended June 30**

Overall results for second quarter 2015 reflect the normal seasonality of the businesses including lower results from the natural gas utilities as the heating season winds down and the ramp up of volumes at Forrest Kerr and Volcano Creek. Significantly weaker commodity prices in second quarter 2015 compared to same quarter 2014 also reduced earnings.

Normalized net income was $9 million ($0.07 per share) for second quarter 2015, compared to $27 million ($0.22 per share) reported for same quarter 2014. Second quarter 2015 earnings benefited from the new income streams of Forrest Kerr, Volcano Creek, and the new US gas-fired power assets acquired in January 2015, as well as the impact of the stronger US dollar on reported results for AltaGas' US assets and lower normalized income taxes. The overall decrease in normalized net income reflects lower contributions from Alberta power assets and sale of natural gas liquids (NGLs), the impact of the turnarounds at the Younger and Harmattan facilities, lower earnings from Petrogas Energy Corp. (Petrogas), lower throughput at some processing plants primarily due to downstream curtailments and higher financing costs primarily related to lower capitalized interest.

The decrease in NGL prices was partially mitigated by AltaGas' hedging strategy. The pre-tax impact of the Younger and Harmattan turnarounds, including lost revenues, was approximately $8 million, which was lower than the previous estimate of $12 million provided in the first quarter report due to certain refurbishment costs meeting the capitalization criteria.

Normalized EBITDA for second quarter 2015 was $107 million, consistent with second quarter 2014. The contributions from Forrest Kerr, Volcano Creek, and the new US gas-fired power assets, as well as the stronger US dollar, were offset by the impact of weaker commodity prices, lower earnings from Petrogas, the Younger and Harmattan turnarounds, and lower throughput at some processing plants primarily due to downstream curtailments.

Normalized funds from operations for second quarter 2015 was $68 million ($0.50 per share), compared to $106 million ($0.86 per share) for same quarter 2014. The decrease was primarily due to the discretionary timing of dividend payments from Petrogas. Petrogas did not declare a dividend in second quarter 2015 compared with a dividend of $28 million (AltaGas' share) in same quarter 2014 as cash was retained in Petrogas in 2015 to fund their capital program. Adjusting for the Petrogas dividend received in second quarter 2014, normalized funds from operations was $78 million. The remaining decrease was driven by the same drivers for EBITDA and higher interest costs, primarily due to Forrest Kerr and Volcano Creek being placed into service in second half 2014.

Normalized operating income for second quarter 2015 was $54 million, compared to $64 million for same quarter 2014, which reflects the factors noted above.

Operating and administrative expense for second quarter 2015 was $121 million, compared to $110 million for same quarter 2014. The increase was primarily due to the turnarounds and new assets brought into service. Depreciation, depletion and amortization expense for second quarter 2015 was $50 million, compared to $42 million for same quarter 2014, due to the new assets placed into service.

Interest expense for second quarter 2015 was $30 million, compared to $23 million for same quarter 2014. Interest expense increased due to lower capitalized interest, primarily due to Forrest Kerr and Volcano Creek entering service in second half 2014.

AltaGas recorded income tax expense of $10 million for second quarter 2015, compared to a tax expense of $6 million in same quarter 2014. The increase is 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. This resulted in a one-time, non-cash $14 million charge to net income applicable to common shareholders from the revaluation of deferred income tax liabilities based on the increased tax rate. This was partially offset by deferred tax recoveries related to unrealized losses on risk management contracts.

Net loss applicable to common shares for second quarter 2015 was $22 million ($0.16 per share), compared to net income of $29 million ($0.23 per share) for same quarter 2014. Net loss applicable to common shares for second quarter 2015 was normalized for after-tax amounts related to statutory tax rate changes, development costs related to energy exports projects, and unrealized gains and losses on risk management contracts and long-term investments. In second quarter 2014, net income applicable to common shares was normalized for unrealized gains on risk management contracts.

**Six Months Ended June 30**

Normalized net income for first half 2015 was $66 million ($0.49 per share), compared with $101 million ($0.82 per share) reported for same period 2014. The decrease was primarily due to lower contributions from Alberta power assets and sale of NGLs, the impact of the turnarounds at Younger and Harmattan, lower earnings from Petrogas, lower throughput at certain processing facilities, the impact of pipeline curtailments downstream of certain AltaGas processing facilities, and higher depreciation and interest expense due to new assets placed into service. These decreases were partially offset by new earnings from Forrest Kerr, lower Sundance PPA costs, the stronger US dollar, and improved results for Energy Services and Blythe.

Normalized funds from operations for first half 2015 was $208 million ($1.54 per share), compared to $238 million ($1.93 per share) for same period 2014. The decrease was primarily due to the discretionary timing of dividend payments from Petrogas as noted above. Adjusting for the Petrogas dividend received in first half 2014, normalized funds from operations were roughly flat period-over-period.

Normalized EBITDA for first half 2015 was $284 million, compared to $287 million for same period 2014. EBITDA generated from Forrest Kerr, Volcano Creek and the new US gas-fired power assets largely offset the impact of lower contributions from Alberta power assets, sale of NGLs, and Petrogas.

Normalized operating income for first half 2015 was $179 million, compared to $202 million for same period 2014, driven by the factors noted above as well as depreciation and amortization of $15 million on new assets placed into service.

Operating and administrative expense for first half 2015 was $238 million, compared to $224 million for the same period 2014. The increase was primarily due to the turnarounds of $5 million and new assets brought into service. Depreciation, depletion and amortization expense for first half 2015 increased to $100 million compared to $83 million for same period 2014 mainly due to new assets placed into service.

Interest expense for first half 2015 was $60 million, compared to $48 million for same period 2014. Interest expense increased primarily due to interest no longer being capitalized due to assets placed into service in second half 2014.

AltaGas recorded income tax expense of $41 million for first half 2015 compared to $23 million for the same period 2014. Income tax expense increased primarily due to the increase in the Alberta corporate income tax rate as discussed above, partially offset by deferred tax recoveries related to unrealized losses on risk management contracts.

Net income applicable to common shares for first half 2015 was $44 million ($0.33 per share) compared to $69 million ($0.56 per share) for same period 2014. Net income applicable to common shares for first half 2015 was normalized for unrealized gains and losses on risk management contracts and long-term investments, development costs incurred for the energy export projects and statutory tax rate changes. In first half 2014, net income applicable to common shares was normalized for unrealized losses on risk management contracts, provisions taken on certain assets, costs associated with early redemption of medium-term notes (MTNs), and gains on asset dispositions.

**2015 OUTLOOK**

AltaGas expects to deliver overall growth in EBITDA in 2015 compared to 2014. The most significant driver is the first full year of contributions from Forrest Kerr and Volcano Creek and the partial year contribution from McLymont Creek run-of-river hydro projects. Other contributing factors such as growth in rate base and customers at the utilities, the new US gas-fired power assets and other smaller growth projects, as well as improved results for Energy Services and the stronger US dollar are also expected to drive EBITDA growth.

Growth in EBITDA is expected to be impacted by lower contributions from Alberta power assets, sale of NGLs, and Petrogas and the turnarounds that occurred in the first half of 2015.

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

In 2015, the Power and Utilities segments are expected to report higher operating income and the Gas segment is expected to be down from 2014 as the weak NGL market conditions are expected to persist in the second half of 2015.

Management estimates an average of 3,100 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.

Activity in AltaGas' Gas business is expected to be driven by the continued development in the Montney basin as well as the abundant supply and relatively low natural gas prices in North America. Given the near term momentum of development in the world class Montney play, AltaGas expects growing demand for processing infrastructure in the area. Surplus natural gas and NGL in western Canada will necessitate energy exports to potentially mitigate the low regional price environment. AltaGas is uniquely positioned to deliver higher netbacks to producers by providing a competitive service offering across the energy value chain and by connecting producers to higher value markets, including Asia.

AltaGas expects to continue its Alberta power hedging strategy in order to balance its market and operational risks. For the remainder of 2015, AltaGas has hedged approximately 30 percent of expected volumes exposed to Alberta power prices at an average price of approximately $54/MWh. AltaGas expects to continue to hedge its exposure to Alberta Power prices throughout 2015 at prices lower than 2014 hedged prices if current forward curves persist throughout 2015.

On June 25, 2015, the Government of Alberta announced that the Specified Gas Emitters Regulation (SGER) will be renewed for a period of two years. Under the new regulation, the carbon levy is set to increase from $15 per tonne to $20 per tonne in 2016 and to $30 per tonne in 2017 and the emission intensities reduction level is set to increase to 15 percent by January 1, 2016 and to 20 percent by January 1, 2017.

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 increased customer and rate base growth. SEMCO Energy Inc. (SEMCO) expects approximately US$2 million of additional earnings in 2015 as a result of the approval of its Main Replacement Program. 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 US utilities and power 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 US 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 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. 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 June 30, 2015, the Corporation had approximately $1.8 billion available on its credit facilities as well as cash on hand of $290 million and debt to total capitalization of 45 percent.

**McLymont Creek Hydroelectric Facility**
At the 66-MW McLymont Creek hydroelectric project, the power house construction is complete and AltaGas is in the final stages of construction of the weir and intake structures. Introduction of backfeed power was achieved at the end of June 2015 and commissioning is well underway. The project is expected to be in service in mid-2015. The facility is contracted with a 60-year EPA with BC Hydro fully indexed to the CPI, as well as an Impact Benefit Agreement with the Tahltan First Nation.

**Townsend Gas Processing Facility**
On August 19, 2014 AltaGas and Painted Pony entered into a 15-year strategic alliance for the development of processing infrastructure and marketing services for natural gas and NGL. In the first phase of the strategic alliance, a 198 Mmcf/d shallow-cut gas processing facility, known as the Townsend Facility, will be constructed and operated by AltaGas. Painted Pony has reserved all of the firm capacity. The Townsend Facility will be located approximately 100 kilometers north of Fort St. John and 20 kilometers southeast of AltaGas' Blair Creek Facility and is estimated to cost $325 to $350 million. AltaGas has begun construction and approximately $100 million of equipment and services have been procured for the project to-date. Initial field installation activities have commenced including mobilization of site facilities and installation of test piles. Construction is expected to ramp up in the second half of 2015, and the facility is expected to be in service by mid-2016.

**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 the project is expected to be in commercial service with the commissioning of the hot oil heat recovery system in third quarter 2015.

## 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Net revenue | **$ 204** | $ 220 | **$ 512** | $ 516 |
| Add (deduct): | | | | |
| Other income | **(2)** | (2) | **(4)** | (11) |
| Income from equity investments | **(5)** | (7) | **-** | (25) |
| Cost of sales | **219** | 260 | **653** | 815 |
| Revenue (GAAP financial measure) | **$ 416** | $ 471 | **$ 1,161** | $ 1,295 |

Management believes that net revenue, which is revenue plus other income plus income from equity investments not held-for-trading, less 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Normalized operating income | **$ 54** | $ 64 | **$ 179** | $ 202 |
| Add (deduct): | | | | |
| Unrealized gain on long-term investments | **1** | - | **1** | - |
| Provision on long-lived assets | **-** | - | **-** | (49) |
| Costs associated with early redemption of MTNs | **-** | - | **-** | (2) |
| Gain on asset dispositions | **-** | - | **-** | 11 |
| Joint venture development costs | **(1)** | - | **(2)** | - |
| Operating income | **54** | 64 | **178** | 162 |
| Add (deduct): | | | | |
| Unrealized gain (loss) on risk management contracts | **(23)** | 3 | **(9)** | (3) |
| Interest expense | **(30)** | (23) | **(60)** | (48) |
| Foreign exchange loss | **(1)** | - | **-** | - |
| Income tax expense | **(10)** | (6) | **(41)** | (23) |
| Net income applicable to non-controlling interests | **(2)** | (2) | **(4)** | (4) |
| Preferred share dividends | **(10)** | (7) | **(20)** | (15) |
| Net income (loss) applicable to common shares (GAAP financial measure) | **$ (22)** | $ 29 | **$ 44** | $ 69 |

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized gains or losses on risk management contracts. The measure is used to assess operating performance since management believes that it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income (Loss) using net income applicable to common shares adjusted for pre-tax unrealized gain or loss on risk management contracts, interest expense, foreign exchange gain (loss), income tax recovery (expense), net income applicable to non-controlling interests and preferred share dividends.

Normalized operating income represents operating income adjusted for non-operating related expenses such as 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).

| **Normalized EBITDA** | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Normalized EBITDA | **$ 107** | $ 107 | **$ 284** | $ 287 |
| Add (deduct): | | | | |
| Unrealized gain on long-term investments | **1** | - | **1** | - |
| Gain on asset dispositions | **-** | - | **-** | 11 |
| Joint venture development costs | **(1)** | - | **(2)** | - |
| Costs associated with early redemption of MTNs | **-** | - | **-** | (2) |
| EBITDA | **107** | 107 | **283** | 296 |
| Add (deduct): | | | | |
| Unrealized gain (loss) on risk management contracts | **(23)** | 3 | **(9)** | (3) |
| Depreciation, depletion and amortization | **(50)** | (42) | **(100)** | (83) |
| Provision on long-lived assets | **-** | - | **-** | (49) |
| Accretion expenses | **(3)** | (1) | **(5)** | (2) |
| Interest expense | **(30)** | (23) | **(60)** | (48) |
| Foreign exchange loss | **(1)** | - | **-** | - |
| Income tax expense | **(10)** | (6) | **(41)** | (23) |
| Net income applicable to non-controlling interests | **(2)** | (2) | **(4)** | (4) |
| Preferred share dividends | **(10)** | (7) | **(20)** | (15) |
| Net income (loss) applicable to common shares (GAAP financial measure) | **$ (22)** | $ 29 | **$ 44** | $ 69 |

EBITDA is a measure of AltaGas' operating profitability without the impact of risk management contracts and prior to how business activities are financed, assets are amortized or earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk on a significant portion of the volumes subject to commodity price fluctuations, and therefore evaluates company performance excluding unrealized gains or losses from risk management contracts. EBITDA is calculated from the Consolidated Statements of Income (Loss) using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, depreciation, depletion and amortization, provision taken on long-lived assets, accretion expense, interest expense, foreign exchange gain (loss), income tax recovery (expense), net income applicable to non-controlling interests, and preferred share dividends.

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as realized/unrealized gain (loss) on long-term investments, costs associated with early redemption of MTNs and gain (loss) on asset dispositions. Normalized EBITDA also includes an adjustment for the project development costs incurred by AIJVLP.

| **Normalized Net Income** | | Three months ended June 30 | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| *($ millions)* | | **2015** | 2014 | | **2015** | 2014 |
| Normalized net income | **$** | **9** | $ 27 | **$** | **66** | $ 101 |
| Add (deduct) after-tax: | | | | | | |
| Unrealized gain (loss) on risk management contracts | | **(17)** | 2 | | **(8)** | (2) |
| Unrealized gain on long-term investments | | **1** | - | | **1** | - |
| Gain on asset dispositions | | **-** | - | | **-** | 9 |
| Provision on long-lived assets | | **-** | - | | **-** | (37) |
| Joint venture development costs | | **(1)** | - | | **(1)** | - |
| Costs associated with early redemption of MTNs | | **-** | - | | **-** | (2) |
| Statutory tax rate change | | **(14)** | - | | **(14)** | - |
| Net income (loss) applicable to common shares (GAAP financial measure) | **$** | **(22)** | $ 29 | **$** | **44** | $ 69 |

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as gain (loss) on asset dispositions, provision taken on long-lived assets and 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.

| **Normalized Funds from Operations** | | Three months ended June 30 | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| *($ millions)* | | **2015** | 2014 | | **2015** | 2014 |
| Normalized funds from operations | **$** | **68** | $ 106 | **$** | **208** | $ 238 |
| Funds from operations | | **68** | 106 | | **208** | 238 |
| Add (deduct): | | | | | | |
| Net change in operating assets and liabilities | | **80** | 6 | | **143** | 49 |
| Asset retirement obligations settled | | **(1)** | - | | **(2)** | (1) |
| Cash from operations (GAAP financial measure) | **$** | **147** | $ 112 | **$** | **349** | $ 286 |

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in operating assets and liabilities in the period and non-operating related one-time 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($ millions)* | **2015** | 2014 | **2015** | 2014 |
| Gas | **$ 21** | $ 40 | **$ 52** | $ 88 |
| Power | **18** | 13 | **33** | 29 |
| Utilities | **22** | 20 | **108** | 101 |
| Sub-total: Operating Segments | **61** | 73 | **193** | 218 |
| Corporate | **(7)** | (9) | **(14)** | (16) |
| | **$ 54** | $ 64 | **$ 179** | $ 202 |

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

## GAS

| **OPERATING STATISTICS** | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Total inlet gas processed (Mmcf/d)(1) | **1,123** | 1,476 | **1,310** | 1,525 |
| Extraction ethane volumes (Bbls/d)(1) | **23,722** | 32,488 | **30,690** | 33,368 |
| Extraction NGL volumes (Bbls/d)(1) | **25,566** | 37,379 | **30,534** | 37,567 |
| Total extraction volumes (Bbls/d)(1) (2) | **49,288** | 69,867 | **61,224** | 70,935 |
| Frac spread - realized ($/Bbl)(1) (3) | **20.58** | 17.31 | **14.56** | 21.86 |
| Frac spread - average spot price ($/Bbl)(1) (4) | **2.51** | 18.14 | **3.31** | 27.21 |

(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.*

During second quarter 2015, AltaGas completed two major turnarounds at the 490 Mmcf/d Harmattan facility and at the 750 Mmcf/d Younger facility.

In second quarter 2015, total inlet gas processed decreased by 353 Mmcf/d, compared to 1,476 Mmf/d in same period 2014. This decrease in volumes was primarily driven by the turnarounds at Harmattan and Younger, and significantly lower commodity prices also made extraction of certain NGLs at some of the facilities uneconomical resulting in reinjection of propane at some facilities. During the quarter, AltaGas completed construction of a new 12-inch inlet sour gas pipeline at Gordondale Gas Processing Facility (Gordondale) to accommodate increased production in the area.

In second quarter 2015, average ethane volumes decreased by 8,766 Bbls/d and NGL volumes decreased by 11,813 Bbls/d compared to same quarter 2014. Lower ethane volumes were due to lower produced volumes at Younger and Harmattan primarily due to the turnarounds. NGL volumes in second quarter 2015 were also impacted by the turnarounds and the lower commodity price environment resulting in reinjections.

**Three Months Ended June 30**

The Gas segment reported normalized operating income of $21 million in second quarter 2015, compared to $40 million in same quarter 2014. The impact of the Harmattan and Younger turnarounds, including lost revenue, was approximately $8 million compared to the previous estimate of $12 million due to certain refurbishment costs meeting the capitalization criteria. The decrease in operating income also reflects the significantly lower commodity price environment, lower earnings from Petrogas as well as the impact of pipeline curtailments downstream of some of the gas processing facilities. The lower earnings from Petrogas' margin-based business were partially offset by higher earnings from Liquefied Petroleum Gas (LPG) exports from Ferndale during second quarter 2015.

During second quarter 2015, AltaGas hedged approximately 3,300 Bbls/d of NGLs at an average price of $26/Bbl. During second quarter 2014, AltaGas hedged 5,000 Bbls/d of NGLs at an average price of $25/Bbl. The average indicative spot NGL frac spread for second quarter 2015 was approximately $3/Bbl compared to approximately $18/Bbl in same quarter 2014.

**Six Months Ended June 30**

The Gas segment reported normalized operating income of $52 million in first half 2015, compared to $88 million in same period 2014. The decrease reflects the impact of weak NGL prices, lower earnings from Petrogas, completion of the two major turnarounds during second quarter 2015, lower throughput at certain gas processing facilities as well as the impact of pipeline curtailments downstream of some 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.

The Gas segment reported operating income of $50 million in first half 2015, compared to $60 million in same period 2014. First quarter 2014 included the impact of the pre-tax provision taken on EDS and JFP transmission pipeline assets of $38 million which was partially offset by a pre-tax gain of $12 million from the sale of the Ante Creek facility.

During first half 2015, AltaGas hedged approximately 3,100 Bbls/d of NGLs at an average price of $27/Bbl. During first half 2014, AltaGas hedged 5,300 Bbls/d of NGLs at an average price of $26/Bbl. The average indicative spot NGL frac spread for first half 2015 was approximately $3/Bbl compared to approximately $27/Bbl in same period 2014.

## POWER

| **OPERATING STATISTICS** | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Volume of power sold (GWh) | **1,287** | 1,067 | **2,437** | 2,248 |
| Average Alberta realized power price ($/MWh) | **48.16** | 51.74 | **46.78** | 58.96 |
| Average price realized on the sale of power ($/MWh) (1) | **68.18** | 55.92 | **64.57** | 62.70 |
| Alberta Power Pool average spot price ($/MWh) | **57.22** | 42.43 | **43.20** | 51.46 |

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

During second quarter 2015, volume of power sold increased by 220 GWh compared to same quarter 2014. Volumes sold during second quarter 2015 were comprised of 945 GWh conventional power generation and 342 GWh of renewable power generation, compared to 953 GWh conventional power generation and 114 GWh renewable power generation in same quarter 2014.

During first half 2015, volume of power sold increased by 189 GWh compared to same period in 2014. Volumes sold during first half 2015 were comprised of 1,934 GWh of conventional power generation and 503 GWh renewable power generation, compared to 2,012 GWh conventional power generation and 236 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 US 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 June 30**

The Power segment reported normalized operating income of $18 million, a 38 percent increase for second quarter 2015, compared to $13 million for same quarter 2014. Normalized operating income increased as a result of the contributions from Forrest Kerr, Volcano Creek and the new US gas-fired power assets acquired in January 2015, which more than offset the impact of weaker Alberta realized power prices and volumes.

In second quarter 2015, AltaGas was 47 percent hedged in Alberta at an average price of $43/MWh. In second quarter 2014, AltaGas was 50 percent hedged at an average price of $60/MWh.

**Six Months Ended June 30**

The Power segment reported normalized operating income of $33 million, 14 percent increase for first half 2015, compared to $29 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 PPA costs, increased results from Blythe due to a major planned maintenance turnaround in early 2014, favourable exchange rates, and lower gas costs at the Alberta gas-fired plants. This was partially offset by lower Alberta realized power prices and volumes. Power generation at Forrest Kerr and Volcano Creek was better than expected, with ongoing operational enhancements and tuning providing the potential for efficiency and generation improvements.

Operating income in the Power segment was $33 million in first half 2015, compared to $18 million in same period 2014, driven by the factors described above. First quarter 2014 operating income included an $11 million pre-tax provision related to certain hydro power assets under development.

In first half 2015, AltaGas was 51 percent hedged in Alberta at an average price of $51/MWh. In first half 2014, AltaGas was 54 percent hedged at an average price of $63/MWh.

## UTILITIES

| OPERATING STATISTICS | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Canadian utilities | | | | |
| Natural gas deliveries - end-use (PJ)(1) | **5.2** | 6.2 | **18.3** | 19.0 |
| Natural gas deliveries - transportation (PJ)(1) | **1.5** | 1.2 | **3.4** | 3.1 |
| US utilities | | | | |
| Natural gas deliveries - end-use (Bcf)(1) | **10.0** | 10.6 | **42.1** | 43.1 |
| Natural gas deliveries - transportation (Bcf)(1) | **10.0** | 8.4 | **23.8** | 20.8 |
| Service sites (2) | **560,755** | 553,320 | **560,755** | 553,320 |
| Degree day variance from normal - AUI (%) (3) | **(9.7)** | 10.8 | **(10.9)** | 6.6 |
| Degree day variance from normal - Heritage Gas (%) (3) | **14.7** | 3.7 | **15.4** | 3.8 |
| Degree day variance from normal - SEMCO Gas (%) (4) | **(1.7)** | 9.9 | **12.6** | 21.1 |
| Degree day variance from normal - ENSTAR (%) (4) | **(17.4)** | (7.7) | **(10.8)** | (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 US 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 US 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 June 30

The Utilities segment reported operating income of $22 million in second quarter 2015, compared to $20 million in same quarter 2014. The increase was mainly due to the impact of the stronger US dollar on reported results for the US businesses, as well as rate base and customer growth across all Utilities. The increase in operating income was partially offset by warmer weather experienced at the US utilities and in Alberta, and higher operating costs.

On June 3, 2015, SEMCO's 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.

### Six Months Ended June 30

The Utilities segment reported operating income of $108 million in first half 2015, compared to $101 million in same period 2014. The increase was mainly due to colder weather experienced in Nova Scotia, rate base and customer growth across all Utilities, and favourable foreign exchange rates. The increase in operating income was partially offset by warmer weather experienced at the US utilities and in Alberta, and higher operating costs due to increased pension, retiree medical, and severance costs.

## CORPORATE

**Three Months Ended June 30**

In the Corporate segment, normalized operating loss for second quarter 2015 was $7 million, compared to $9 million in same quarter 2014. The lower normalized loss was primarily due to decreased general and administrative expenses.

**Six Months Ended June 30**

Normalized operating loss for the first six months 2015 was $14 million, compared to $16 million in same quarter 2014. The operating loss in the Corporate segment for first half 2015 was $13 million compared to $18 million for same period 2014. First quarter 2014 included $2 million of pre-tax costs associated with an early redemption of MTNs.

## INVESTED CAPITAL

During second quarter 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $149 million, compared to $139 million in same quarter 2014.

The invested capital in second quarter 2015 included maintenance capital of $11 million (2014 - $1 million) in the Gas segment and $1 million (2014 - $nil) in the Power segment. Gas segment maintenance capital for second quarter 2015 included $7 million related to the Harmattan turnaround (2014 - $nil).

**Invested Capital - Investment Type**

**Three months ended June 30, 2015**

| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
|---|---|---|---|---|---|
| Invested capital: | | | | | |
| Property, plant and equipment | **$ 50** | **$ 44** | **$ 48** | **$ 1** | **$ 143** |
| Intangible assets | **1** | **-** | **1** | **4** | **6** |
| Long-term investments | **-** | **-** | **-** | **-** | **-** |
| Invested capital | **51** | **44** | **49** | **5** | **149** |
| Disposals: | | | | | |
| Property, plant and equipment | **-** | **-** | **-** | **-** | **-** |
| Net Invested capital | **$ 51** | **$ 44** | **$ 49** | **$ 5** | **$ 149** |

Three months ended June 30, 2014

| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
|---|---|---|---|---|---|
| Invested capital: | | | | | |
| Property, plant and equipment | $ 8 | $ 87 | $ 37 | $ 1 | $ 133 |
| Intangible assets | - | - | 1 | 4 | 5 |
| Long-term investments | 1 | - | - | - | 1 |
| | 9 | 87 | 38 | 5 | 139 |
| Disposals: | | | | | |
| Property, plant and equipment | (1) | - | - | - | (1) |
| Net Invested capital | $ 8 | $ 87 | $ 38 | $ 5 | $ 138 |

During first half 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $280 million, compared to $258 million in same period 2014. The net invested capital was $280 million for the six months ended June 30, 2015, compared to $231 million in same period 2014.

The invested capital in first half 2015 included maintenance capital of $12 million (2014 - $3 million) in the Gas segment and $1 million (2014 - $nil) in the Power segment.

**Invested Capital - Investment Type**

**Six months ended June 30, 2015**

| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
|---|---|---|---|---|---|
| Invested capital: | | | | | |
| Property, plant and equipment | **$ 71** | **$ 109** | **$ 71** | **$ 2** | **$ 253** |
| Intangible assets | **1** | **9** | **1** | **10** | **21** |
| Long-term investments | **6** | **-** | **-** | **-** | **6** |
| Invested capital | **78** | **118** | **72** | **12** | **280** |
| Disposals: | | | | | |
| Property, plant and equipment | **-** | **-** | **-** | **-** | **-** |
| Net Invested capital | **$ 78** | **$ 118** | **$ 72** | **$ 12** | **$ 280** |

Six months ended June 30, 2014

| *($ millions)* | Gas | Power | Utilities | Corporate | Total |
|---|---|---|---|---|---|
| Invested capital: | | | | | |
| Property, plant and equipment | $ 21 | $ 167 | $ 56 | $ 3 | $ 247 |
| Intangible assets | - | - | 1 | 7 | 8 |
| Long-term investments | 3 | - | - | - | 3 |
| | 24 | 167 | 57 | 10 | 258 |
| Disposals: | | | | | |
| Property, plant and equipment | (27) | - | - | - | (27) |
| Net Invested capital | $ (3) | $ 167 | $ 57 | $ 10 | $ 231 |

## 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 second 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 interest rate and 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 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 $8.94/MWh to $998.04/MWh in second quarter 2015 and $7.88/MWh to $897.21/MWh in second quarter 2014. The average Alberta spot price was $57.22/MWh in second quarter 2015 (second quarter 2014 - $42.43/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 $48.16/MWh in second quarter 2015 (second quarter 2014 - $51.74/MWh). For the remainder of 2015, AltaGas has hedged approximately 30 percent of expected volumes exposed to Alberta power prices at an average price of $54/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 second quarter 2015, the Corporation hedged approximately 3,300 Bbls/d of NGLs at an average price of approximately $26/Bbl. The average indicative spot NGL frac spread for second quarter 2015 was an estimated $2.51/Bbl (second quarter 2014 – $18.14/Bbl). The average NGL frac spread realized by AltaGas in second quarter 2015 was $20.58/Bbl (second quarter 2014 - $17.31/Bbl). Management estimates an average of approximately 3,100 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.

**Interest Rate Forward Contracts**

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. As at June 30, 2015, the Corporation had no interest rate swaps outstanding. At June 30, 2015, the Corporation had fixed the interest rate on 86 percent of its debt including MTNs (June 30, 2014 - 77 percent).

**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 June 30, 2015, management designated US$356 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

| Cash Flows | | Three months ended | | June 30 | | Six months ended | | June 30 |
|---|---|---|---|---|---|---|---|---|
| ($ millions) | | **2015** | | 2014 | | **2015** | | 2014 |
| Cash from operations | **$** | **147** | $ | 112 | **$** | **349** | $ | 286 |
| Investing activities | | **(89)** | | (128) | | **(250)** | | (218) |
| Financing activities | | **(58)** | | (33) | | **(183)** | | (85) |
| Effect of exchange rate | | **(1)** | | (2) | | **3** | | - |
| Decrease in cash and cash equivalents | **$** | **(1)** | $ | (51) | **$** | **(81)** | $ | (17) |

**Cash from Operations**

Cash from operations increased by $63 million for the six months ended June 30, 2015 compared to the same period in 2014 primarily due to the net change in operating assets and liabilities. The net change in operating assets and liabilities was a net cash inflow of $143 million for the six months ended June 30, 2015 compared to $49 million for the same period in 2014. The higher net cash inflow from change in operating assets and liabilities in 2015 is due to changes in inventory, regulatory assets, regulatory liabilities and accounts payable largely as a result of changes in gas commodity costs. The increase in cashflow related to changes in operating assets and liabilities was partially offset by the impact of the $28 million dividend received from Petrogas in second quarter 2014 compared to no Petrogas dividends received in first half 2015 as cash was retained to fund their capital program.

| Working Capital | | | | |
|---|---|---|---|---|
| As at June 30 | | **2015** | | 2014 |
| ($ millions except current ratio) | | | | |
| Current assets | **$** | **737** | $ | 444 |
| Current liabilities | | **697** | | 543 |
| Working capital | | **40** | | (99) |
| Current ratio | | **1.06** | | 0.82 |

Working capital surplus was $40 million as at June 30, 2015, compared to working capital deficit of $99 million as at June 30, 2014. The working capital ratio was 1.06 at the end of second quarter 2015, compared to 0.82 at the end of same quarter 2014. The working capital ratio increased primarily due to a higher cash balance as at June 30, 2015 as a result of proceeds from the August 2014 common equity issuance.

**Investing Activities**

Cash used in investing activities in first half 2015 was $250 million, compared to $218 million in same period 2014. Investing activities in first half 2015 included expenditures of $244 million for property, plant and equipment, $19 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 first half 2014 primarily comprised of $237 million for property, plant and equipment and $9 million for intangible assets, partially offset by proceeds of $27 million received on disposition of assets.

**Financing Activities**

Cash used in financing activities in first half 2015 was $183 million, compared to $85 million in same period 2014. Financing activities in first half 2015 were primarily comprised of net proceeds from issuance of common shares of $53 million, issuance of long-term debt of $376 million, partially offset by repayments of long-term and short-term debts of $404 million and $64 million, respectively. Financing activities in first half 2014 were primarily comprised of net proceeds from issuance of common shares of $45 million, issuance of long-term debt of $746 million, partially offset by repayments of long-term and short-term debts of $696 million and $60 million, respectively. Total dividends paid in first half 2015 were $141 million, compared to $112 million in same period 2014. The increase was due to higher 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 cashflow stability and sustainability.

As at June 30, 2015, AltaGas had MTNs of $2,730 million, PNG debenture notes of $56 million, and SEMCO long-term debt of $474 million outstanding. In addition, AltaGas had $48 million drawn under the bank credit facilities and $133 million of letters of credit outstanding. As at June 30, 2015, AltaGas' current portion of long-term debt was $261 million. As at June 30, 2015, AltaGas had $290 million of cash and cash equivalents.

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

AltaGas' debt-to-total capitalization ratio as at June 30, 2015 was 45 percent (December 31, 2014 - 45 percent).

| ($ millions) | | **June 30, 2015** | | December 31, 2014 |
|---|---|---|---|---|
| Debt | | | | |
| Short-term debt | **$** | **13** | $ | 72 |
| Current portion of long-term debt | | **261** | | 214 |
| Long-term debt | | **3,041** | | 3,050 |
| Less: cash and cash equivalent | | **(290)** | | (371) |
| Less: short-term investments | | **-** | | (50) |
| Net debt | | **3,025** | | 2,915 |
| Shareholders' equity | | **3,610** | | 3,541 |
| Non-controlling interests | | **33** | | 33 |
| Total capitalization | **$** | **6,668** | $ | 6,489 |
| Debt-to-total capitalization ratio (%) | | **45** | | 45 |

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The following table summarizes the Corporation's debt covenants for all credit facilities as at June 30, 2015:

| Ratios | Debt covenant requirements |
|---|---|
| Debt-to-capitalization | not greater than 65 percent |
| EBITDA-to-interest expense | not less than 2.5x |
| EBITDA-to-interest expense (SEMCO) | not less than 2.25x |
| Debt-to-capitalization (SEMCO) | not greater than 60 percent |
| Debt-to-capitalization (PNG) | not greater than 65 percent |

On August 23, 2013, a $4 billion base shelf prospectus valid for 25 months was filed. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance. As at June 30, 2015, $1.8 billion remains available on the base shelf prospectus.

| **Credit Facilities** ($ millions) | Borrowing capacity | **Drawn at June 30 2015** | Drawn at December 31 2014 |
|---|---|---|---|
| Demand operating facilities | $ 70 | **$ 4** | $ 4 |
| Extendible revolving letter of credit facility | 150 | **65** | 113 |
| Letter of credit demand facility | 100 | **43** | - |
| PNG operating facility | 25 | **14** | 14 |
| Bilateral letter of credit facility | 40 | **15** | 13 |
| AltaGas Ltd. revolving credit facility (1) | 1,400 | **39** | - |
| SEMCO Energy US$ unsecured credit facility (1) (2) | 150 | **1** | 38 |
| | $ 1,935 | **$ 181** | $ 182 |

(1) *Amount drawn at June 30, 2015 converted at June 2015 month-end rate of 1 US dollar = 1.2474 Canadian dollar (Amount drawn at December 31, 2014 converted at December 2014 month-end rate of 1 US dollar = 1.1601 Canadian dollar).*

(2) *Borrowing capacity assumed at par.*

## SHARE INFORMATION

As at June 30, 2015, AltaGas had outstanding 135 million common shares, 8 million series A Preferred Shares, 8 million series C US$ Preferred Shares, 8 million series E Preferred Shares and 8 million series G preferred shares with a combined market capitalization of approximately $5.9 billion based on a closing trading price on June 30, 2015 of $38.04 per common share, $18.17 per series A Preferred Share, $22.05 per series C US$ Preferred Share, $23.53 per series E Preferred Share, and $23.46 per series G preferred shares.

As at June 30, 2015, there were 5 million options outstanding and 3 million options exercisable under the terms of the share option plan.

## 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.

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 | **-** | 0.4425 |
| Fourth quarter | **-** | 0.4425 |
| **Total** | **$ 0.9100** | $ 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 |
| Fourth quarter | **-** | 0.3125 |
| **Total** | **$ 0.6250** | $ 1.2500 |

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

| (US$ per preferred share) | **2015** | 2014 |
|---|---|---|
| First quarter | **$ 0.275** | $ 0.275 |
| Second quarter | **0.275** | 0.275 |
| Third quarter | **-** | 0.275 |
| Fourth quarter | **-** | 0.275 |
| **Total** | **$ 0.550** | $ 1.100 |

**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 |
| Fourth quarter | **-** | 0.3125 |
| **Total** | **$ 0.6250** | $ 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 | **-** | 0.2896 |
| Fourth quarter | **-** | 0.2969 |
| **Total** | **$ 0.5938** | $ 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, depletion 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 six months ended June 30, 2015.

## FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update 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 Update and the impact on AltaGas' consolidated financial statements is under assessment.

In April 2015, FASB issued ASU No. 2015-03 "Interest - Imputation of Interest", which changes the presentation of debt issuance costs in the financial statements. The amendments in this Update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. An entity should apply the new guidance on a retrospective basis. The amendments in this Update are effective for fiscal year, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this update is not expected to have a material impact on AltaGas' consolidated financial statements.

## 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 United States Generally Accepted Accounting Principles (US 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 United States Generally Accepted Accounting Principles (US GAAP).

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

| *($ millions)* | **Q2-15** | **Q1-15** | Q4-14 | Q3-14 | Q2-14 | Q1-14 | Q4-13 | Q3-13 |
|---|---|---|---|---|---|---|---|---|
| Total revenue | **416** | 744 | 667 | 444 | 471 | 824 | 581 | 390 |
| Net revenue(2) | **204** | 307 | 285 | 217 | 220 | 297 | 265 | 247 |
| Normalized operating income(2) | **54** | 125 | 105 | 59 | 64 | 137 | 112 | 64 |
| Net income before taxes | **-** | 109 | 17 | 30 | 44 | 66 | 75 | 57 |
| Net income (loss) applicable to common shares | **(22)** | 66 | 10 | 17 | 29 | 40 | 53 | 43 |
| *($ per share)* | **Q2-15** | Q1-15 | Q4-14 | Q3-14 | Q2-14 | Q1-14 | Q4-13 | Q3-13 |
| Net income (loss) per common shares | | | | | | | | |
| Basic | **(0.16)** | 0.49 | 0.08 | 0.13 | 0.23 | 0.33 | 0.44 | 0.36 |
| Diluted | **(0.16)** | 0.49 | 0.08 | 0.13 | 0.23 | 0.32 | 0.43 | 0.35 |
| Dividends declared | **0.47** | 0.44 | 0.44 | 0.44 | 0.42 | 0.38 | 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.*

Significant items that impacted individual quarterly earnings were as follows:

- In third quarter 2013, AltaGas reported a $38 million pre-tax gain on the sale of Pacific Trail Pipelines Limited Partnership (PTP) by PNG;
- In third quarter 2013, AltaGas recorded provisions of $19 million related to the planned sale of certain non-core gas and utility assets;
- In fourth quarter 2013, AltaGas sold ECNG Energy L.P. (ECNG). AltaGas recorded a pre-tax gain of $4 million and transaction costs of $0.5 million related to this transaction;
- In fourth quarter 2013, AltaGas acquired a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. AltaGas paid for the initial 25 percent interest with 3 million shares priced at $35.69 per share and $231 million of cash;
- In fourth quarter 2013, AltaGas reclassified an other-than-temporary pre-tax loss of $4.3 million on its investment in Alterra from other comprehensive income to income for the period;
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3 million related to six wind projects under development;
- In first quarter 2014, AltaGas completed sale of Ante Creek, a gas processing facility located near Sturgeon Lake, northwestern Alberta. The transaction closed on February 12, 2014, with a realized pre-tax gain from the sale of the asset of $12 million;
- In first quarter 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2 million;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $38 million for EDS and JFP transmission pipeline assets that will be sold to NOVA Chemicals in March 2017;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $11 million for certain hydro power development projects in British Columbia;
- In third quarter 2014, Forrest Kerr was brought into service but did not contribute significantly to quarterly results due to limited power generation during the initial ramp up period;
- In fourth quarter 2014, AltaGas early redeemed $300 million of senior unsecured MTNs resulting in total pre-tax cost of $15 million;
- In fourth quarter 2014, AltaGas recorded a pre-tax provision of $70 million for certain gas processing assets; and
- In second quarter 2015, AltaGas recorded 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.

# Consolidated Balance Sheets
(condensed and unaudited)

| **As at** *($ millions)* | **June 30 2015** | December 31 2014 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 289.6** | $ 371.0 |
| Short-term investment | **-** | 50.0 |
| Accounts receivable, net of allowances | **224.7** | 352.4 |
| Inventory *(note 6)* | **115.2** | 155.3 |
| Restricted cash holdings from customers | **3.0** | 4.2 |
| Regulatory assets | **5.0** | 12.8 |
| Risk management assets *(note 9)* | **63.3** | 70.8 |
| Prepaid expenses and other current assets | **34.0** | 41.9 |
| Deferred income taxes | **2.3** | - |
| | **737.1** | 1,058.4 |
| **Property, plant and equipment** | **5,631.6** | 5,337.0 |
| **Intangible assets** | **370.9** | 356.9 |
| **Goodwill** *(note 7)* | **823.1** | 785.1 |
| **Regulatory assets** | **316.7** | 302.0 |
| **Risk management assets** *(note 9)* | **21.3** | 21.1 |
| **Deferred income taxes** | **15.7** | 2.2 |
| **Restricted cash holdings from customers** | **11.2** | 12.2 |
| **Long-term investments and other assets** | **98.7** | 84.6 |
| **Investments accounted for by equity method** | **468.5** | 453.9 |
| | **$ 8,494.8** | $ 8,413.4 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | **$ 281.0** | $ 343.6 |
| Dividends payable | **21.7** | 19.8 |
| Short-term debt | **13.2** | 72.4 |
| Current portion of long-term debt *(note* 8) | **260.7** | 214.4 |
| Customer deposits | **23.8** | 34.9 |
| Regulatory liabilities | **18.9** | 10.0 |
| Risk management liabilities *(note 9)* | **50.2** | 43.5 |
| Deferred income taxes | **0.3** | 2.1 |
| Other current liabilities | **27.2** | 24.4 |
| | **697.0** | 765.1 |
| **Long-term debt** *(note 8)* | **3,041.4** | 3,049.6 |
| **Asset retirement obligations** | **72.5** | 70.9 |
| **Deferred income taxes** *(note 15)* | **517.2** | 467.2 |
| **Regulatory liabilities** | **147.7** | 136.0 |
| **Risk management liabilities** *(note 9)* | **26.8** | 14.7 |
| **Other long-term liabilities** *(note 10)* | **208.9** | 204.5 |
| **Future employee obligations** | **140.6** | 131.2 |
| | **4,852.1** | 4,839.2 |

| **As at** ($ millions) | | **June 30 2015** | | December 31 2014 |
|---|---|---|---|---|
| **Shareholders' equity** | | | | |
| Common shares, no par values, unlimited shares authorized; 2015 - 135.4 million and 2014 - 133.9 million issued and outstanding *(note 11)* | | **2,814.3** | | 2,759.9 |
| Preferred shares *(note 11)* | | **788.4** | | 788.4 |
| Contributed surplus | | **15.3** | | 14.9 |
| Accumulated deficit | | **(263.6)** | | (185.2) |
| Accumulated other comprehensive income (AOCI) | | **255.1** | | 163.1 |
| **Total shareholders' equity** | | **3,609.5** | | 3,541.1 |
| **Non-controlling interests** | | **33.2** | | 33.1 |
| | | **3,642.7** | | 3,574.2 |
| | **$** | **8,494.8** | $ | 8,413.4 |

*Commitments and contingencies (note 13).*
*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Income (Loss)

(condensed and unaudited)

| *($ millions except per share amounts)* | Three months ended June 30 **2015** | 2014 | Six months ended June 30 **2015** | 2014 |
|---|---|---|---|---|
| **REVENUE** | | | | |
| Sales | **$ 80.0** | $ 167.5 | **$ 212.9** | $ 435.7 |
| Services | **180.5** | 129.8 | **351.2** | 249.5 |
| Regulated operations | **178.5** | 172.8 | **605.9** | 613.5 |
| Other revenue (loss) | **(0.3)** | (1.7) | **(0.2)** | (0.9) |
| Unrealized gain (loss) on risk management contracts *(note 9)* | **(22.6)** | 2.8 | **(9.2)** | (2.8) |
| | **416.1** | 471.2 | **1,160.6** | 1,295.0 |
| **EXPENSES** | | | | |
| Cost of sales, exclusive of items shown separately | **219.3** | 260.2 | **652.5** | 814.5 |
| Operating and administrative | **120.7** | 109.9 | **238.1** | 223.8 |
| Accretion expenses | **2.7** | 1.0 | **5.4** | 2.1 |
| Depreciation, depletion and amortization | **49.8** | 41.8 | **99.6** | 83.0 |
| Provision on long-lived assets *(note 4)* | **-** | - | **-** | 49.2 |
| | **392.5** | 412.9 | **995.6** | 1,172.6 |
| **Income (loss) from equity investments** | **5.3** | 7.3 | **(0.4)** | 24.6 |
| **Other income** | **2.4** | 1.6 | **4.2** | 11.4 |
| **Foreign exchange gain (loss)** | **(0.8)** | (0.2) | **0.4** | 0.2 |
| **Interest expense** | | | | |
| Short-term debt | **(0.3)** | (0.3) | **(0.7)** | (0.7) |
| Long-term debt | **(30.1)** | (22.7) | **(59.5)** | (47.6) |
| **Income before income taxes** | **0.1** | 44.0 | **109.0** | 110.3 |
| **Income tax expense** *(note 15)* | | | | |
| Current | **3.2** | 4.9 | **15.0** | 14.0 |
| Deferred | **6.8** | 0.8 | **25.5** | 8.5 |
| **Net income (loss) after taxes** | **(9.9)** | 38.3 | **68.5** | 87.8 |
| **Net income applicable to non-controlling interests** | **2.0** | 2.0 | **4.1** | 4.2 |
| **Net income (loss) applicable to controlling interests** | **(11.9)** | 36.3 | **64.4** | 83.6 |
| Preferred share dividends | **(10.1)** | (7.4) | **(20.2)** | (14.8) |
| **Net income (loss) applicable to common shares** | **$ (22.0)** | $ 28.9 | **$ 44.2** | $ 68.8 |
| Net income (loss) per common share *(note 12)* | | | | |
| Basic | **$ (0.16)** | $ 0.23 | **$ 0.33** | $ 0.56 |
| Diluted | **$ (0.16)** | $ 0.23 | **$ 0.33** | $ 0.55 |
| **Weighted average number of common shares outstanding** *(note 12)* *(millions)* | | | | |
| Basic | **135.0** | 123.3 | **134.6** | 122.9 |
| Diluted | **135.0** | 125.4 | **135.9** | 124.9 |

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Comprehensive Income (Loss)

(condensed and unaudited)

| ($ millions) | Three months ended June 30 2015 | Three months ended June 30 2014 | Six months ended June 30 2015 | Six months ended June 30 2014 |
|---|---|---|---|---|
| **Net income (loss) after taxes** | **$ (9.9)** | $ 38.3 | **$ 68.5** | $ 87.8 |
| Total other comprehensive income (loss), net of taxes | **(24.0)** | (40.5) | **92.0** | 10.8 |
| **Comprehensive income (loss) attributable to common shareholders and non-controlling interests, net of tax** | **$ (33.9)** | $ (2.2) | **$ 160.5** | $ 98.6 |
| | | | | |
| **Comprehensive income (loss) attributable to:** | | | | |
| Non-controlling interests | **$ 2.0** | $ 2.0 | **$ 4.1** | $ 4.2 |
| Controlling interests | **(35.9)** | (4.2) | **156.4** | 94.4 |
| | **$ (33.9)** | $ (2.2) | **$ 160.5** | $ 98.6 |

# Consolidated Accumulated Other Comprehensive Income (Loss) [1]

| ($ millions) | Available-for-sale | Cash flow hedges | Defined benefit pension 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 | (5.0) | (0.2) | - | (29.7) | 134.6 | 4.8 | 104.5 |
| Amounts reclassified from OCI *(note 3)* | - | (13.1) | 0.6 | - | - | - | (12.5) |
| Net current period other comprehensive income (loss) | $ (5.0) | $ (13.3) | $ 0.6 | $ (29.7) | $ 134.6 | $ 4.8 | $ 92.0 |
| **Ending balance, June 30, 2015[2] [3] [4] [5]** | **$ (17.0)** | **$ -** | **$ (9.0)** | **$ (100.6)** | **$ 376.9** | **$ 4.8** | **$255.1** |
| | | | | | | | |
| Opening balance, January 1, 2014 | $ (3.0) | $ (10.4) | $ (5.7) | $ (35.9) | $ 94.5 | $ - | $ 39.5 |
| OCI before reclassification | 0.3 | 5.4 | 0.1 | (2.0) | 6.1 | - | 9.9 |
| Amounts reclassified from OCI *(note 3)* | - | 1.0 | (0.1) | - | - | - | 0.9 |
| Net current period other comprehensive income (loss) | $ 0.3 | $ 6.4 | $ - | $ (2.0) | $ 6.1 | $ - | $ 10.8 |
| **Ending balance, June 30, 2014[2] [3] [4] [5]** | $ (2.7) | $ (4.0) | $ (5.7) | $ (37.9) | $ 100.6 | $ - | $ 50.3 |

(1) *All amounts are net of tax where applicable. Amounts in parenthesis indicate debits.*

(2) *Available-for-sale - net of tax recovery $1.6 (June 30, 2014 - tax recovery $0.4 million).*

(3) *Cash flow hedges - net of tax nil (June 30, 2014 - tax recovery $1.4 million).*

(4) *Defined benefit pension plans - net of tax recovery $3.0 (June 30, 2014 - tax recovery $1.9 million).*

(5) *Hedge net investment - net of tax recovery $12.4 (June 30, 2014 - tax recovery $5.5 million).*

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Equity

(condensed and unaudited)

| | Six months ended June 30 | |
|---|---|---|
| *($ millions)* | **2015** | 2014 |
| **Common shares** *(note 11)* | | |
| Balance, beginning of period | **$ 2,759.9** | $ 2,211.4 |
| Shares issued for cash on exercise of options | **11.6** | 14.6 |
| Shares issued under DRIP [1] | **42.8** | 31.7 |
| Balance, end of period | **2,814.3** | 2,257.7 |
| **Preferred shares** *(note 11)* | | |
| Balance, beginning of period | **788.4** | 589.6 |
| Series E issued | **-** | (0.5) |
| Balance, end of period | **788.4** | 589.1 |
| **Contributed surplus** | | |
| Balance, beginning of period | **14.9** | 13.4 |
| Share options expense | **1.7** | 2.1 |
| Exercise of share options | **(1.0)** | (1.3) |
| Forfeiture of share options | **(0.3)** | (0.1) |
| Balance, end of period | **15.3** | 14.1 |
| **Accumulated deficit** | | |
| Balance, beginning of period | **(185.2)** | (62.1) |
| Net income applicable to controlling interests | **64.4** | 83.6 |
| Common share dividends | **(122.6)** | (99.1) |
| Preferred share dividends | **(20.2)** | (14.8) |
| Balance, end of period | **(263.6)** | (92.4) |
| **Accumulated other comprehensive income (loss)** | | |
| Balance, beginning of period | **163.1** | 39.5 |
| Other comprehensive income | **92.0** | 10.8 |
| Balance, end of period | **255.1** | 50.3 |
| **Total shareholders' equity** | **3,609.5** | 2,818.8 |
| | | |
| **Non-controlling interests** | | |
| Balance, beginning of period | **33.1** | 37.8 |
| Net income applicable to non-controlling interests | **4.1** | 4.2 |
| Distribution by subsidiaries to non-controlling interests | **(4.0)** | (6.2) |
| Balance, end of period | **33.2** | 35.8 |
| **Total equity** | **$ 3,642.7** | $ 2,854.6 |

[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 June 30 2015 | Three months ended June 30 2014 | Six months ended June 30 2015 | Six months ended June 30 2014 |
|---|---|---|---|---|
| **Cash from operations** | | | | |
| Net income (loss) after taxes | **$ (9.9)** | $ 38.3 | **$ 68.5** | $ 87.8 |
| Items not involving cash: | | | | |
| Depreciation, depletion and amortization | **49.8** | 41.8 | **99.6** | 83.0 |
| Provision on long-lived assets | **-** | - | **-** | 49.2 |
| Accretion expenses | **2.7** | 1.0 | **5.4** | 2.1 |
| Share-based compensation | **0.7** | 1.0 | **1.4** | 2.0 |
| Deferred income tax expense | **6.8** | 0.8 | **25.5** | 8.5 |
| (Gain) loss on sale of assets | **-** | 0.2 | **-** | (11.1) |
| Income (loss) from equity investments | **(5.3)** | (7.3) | **0.4** | (24.6) |
| Unrealized (gain) loss on risk management contracts | **22.6** | (2.8) | **9.2** | 2.8 |
| Unrealized gain on long-term investments | **(0.6)** | (0.4) | **(0.9)** | (0.4) |
| Losses from extinguishment of debts | **-** | - | **-** | 2.1 |
| Other | **2.0** | 1.6 | **4.2** | (0.9) |
| Asset retirement obligations settled | **(1.2)** | (0.3) | **(1.7)** | (0.7) |
| Distributions from (contributions to) equity investments | **(0.6)** | 31.8 | **(4.9)** | 37.2 |
| Changes in operating assets and liabilities: | | | | |
| Accounts receivable | **146.7** | 157.0 | **149.2** | 152.9 |
| Inventory | **(36.4)** | (43.6) | **50.9** | 19.4 |
| Other current assets | **4.4** | (1.2) | **14.3** | 10.9 |
| Regulatory assets (current) | **4.6** | (0.6) | **8.9** | (33.9) |
| Accounts payable and accrued liabilities | **(34.5)** | (102.6) | **(57.0)** | (74.7) |
| Customer deposits | **1.5** | 1.2 | **(13.0)** | (14.8) |
| Regulatory liabilities (current) | **0.5** | (0.4) | **8.1** | (1.3) |
| Other current liabilities | **(1.2)** | (0.8) | **(11.7)** | (6.9) |
| Other operating assets and liabilities | **(6.0)** | (3.0) | **(7.1)** | (3.1) |
| | **146.6** | 111.7 | **349.3** | 285.5 |
| **Investing activities** | | | | |
| Change in restricted cash holdings from customers | **0.4** | (0.1) | **1.4** | (0.2) |
| Acquisition of property, plant and equipment | **(128.9)** | (119.5) | **(243.6)** | (236.7) |
| Acquisition of intangible assets | **(9.1)** | (5.5) | **(18.5)** | (9.4) |
| Proceeds from dispositions of assets | **0.1** | 0.6 | **0.1** | 27.4 |
| Maturity of short-term investment | **50.0** | - | **50.0** | - |
| Contributions to equity investments | **(0.3)** | (2.8) | **(6.1)** | (3.9) |
| Business acquisitions, net of cash acquired | **(1.6)** | (0.2) | **(33.6)** | (0.2) |
| Acquisition of equity investment | **-** | - | **-** | 5.2 |
| | **(89.4)** | (127.5) | **(250.3)** | (217.8) |

| ($ millions) | Three months ended June 30 2015 | 2014 | Six months ended June 30 2015 | 2014 |
|---|---|---|---|---|
| **Financing activities** | | | | |
| Net issuance (repayment) of short-term debt | **12.5** | 18.1 | **(63.8)** | (59.9) |
| Issuance of long-term debt, net of debt issuance costs | **376.2** | 105.3 | **375.9** | 746.2 |
| Repayment of long-term debt | **(400.2)** | (119.8) | **(403.7)** | (697.7) |
| Dividends - common shares | **(61.4)** | (49.6) | **(120.7)** | (96.4) |
| Dividends - preferred shares | **(10.1)** | (7.4) | **(20.2)** | (15.3) |
| Distributions to non-controlling interest | **(2.5)** | (4.2) | **(4.0)** | (6.2) |
| Net proceeds from shares issued on exercise of options | **6.2** | 8.3 | **10.6** | 13.3 |
| Net proceeds from issuance of common shares | **21.7** | 16.3 | **42.7** | 31.7 |
| Costs of issuance of preferred shares Series E | **-** | - | **-** | (0.5) |
| | **(57.6)** | (33.0) | **(183.2)** | (84.8) |
| **Effect of exchange rate changes on cash and cash equivalents** | **(0.7)** | (1.5) | **2.8** | 0.2 |
| **Change in cash and cash equivalents** | **(0.4)** | (48.8) | **(84.2)** | (17.1) |
| **Cash and cash equivalents, beginning of period** | **290.7** | 78.2 | **371.0** | 44.8 |
| **Cash and cash equivalents, end of period** | **$ 289.6** | $ 27.9 | **$ 289.6** | $ 27.9 |

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

| ($ millions) | Three months ended June 30 2015 | 2014 | Six months ended June 30 2015 | 2014 |
|---|---|---|---|---|
| Interest paid (net of capitalized interest) | **$ 21.5** | $ 19.9 | **$ 58.9** | $ 43.7 |
| Income taxes paid | **$ 3.4** | $ 2.9 | **$ 12.2** | $ 11.9 |

*See accompanying notes to the Consolidated Financial Statements.*

# Notes to the Condensed Interim Consolidated Financial Statements (Unaudited)

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

**1. ORGANIZATION AND OVERVIEW OF BUSINESS**

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by the Corporation, 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., and AltaGas Services (US) Inc.

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, transmission, 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.

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 (US 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 US 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), US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under US 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 US 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 US 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".

**SIGNIFICANT ACCOUNTING POLICIES**

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.

**USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY**

The preparation of Consolidated Financial Statements in accordance with US 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, depletion 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 requires 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.

## FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update 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 Update 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 Update 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 Update 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 Update 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 Update 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 Update and the impact on AltaGas' consolidated financial statements is under assessment.

In April 2015, FASB issued ASU No. 2015-03 "Interest - Imputation of Interest", which changes the presentation of debt issuance costs in the financial statements. The amendments in this Update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. An entity should apply the new guidance on a retrospective basis. The amendments in this Update are effective for fiscal year, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this update is not expected to have a material impact on AltaGas' consolidated financial statements.

### 3. RECLASSIFICATION FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

| AOCI components reclassified | Income Statement line item | | **Three months ended June 30, 2015** | | **Six months ended June 30, 2015** |
|---|---|---|---|---|---|
| Cash flow hedges - commodity contracts | | | | | |
| Commodity contracts - NGL (realized effective portion) | Service revenue | | **(3.3)** | | **(7.2)** |
| Commodity contracts - NGL (discontinuation of hedge accounting)(1) | Unrealized gains on risk management contracts | | **(6.2)** | | **(10.3)** |
| Defined benefit pension plans | Operating and administrative expense | | **-** | | **0.8** |
| | Total before income taxes | | **(9.5)** | | **(16.7)** |
| Deferred income taxes | Income tax expenses – Deferred | | **2.4** | | **4.2** |
| | | **$** | **(7.1)** | **$** | **(12.5)** |

(1) During the three and six months ended June 2015, AltaGas discontinued cashflow 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 June 30, 2014 | | Six months ended June 30, 2014 |
|---|---|---|---|---|---|
| Cash flow hedges - commodity contracts | | | | | |
| Commodity contracts - NGL (ineffective hedge) | Unrealized gains on risk management contracts | $ | 0.1 | $ | 0.9 |
| Bond forward | Interest expense – Long-term debt | | - | | 0.1 |
| | Other income (expenses) | | - | | 0.2 |
| Defined benefit pension plans | Operating and administrative expense | | 0.1 | | 0.1 |
| | Total before income taxes | | 0.2 | | 1.3 |
| Deferred income taxes | Income tax expenses – Deferred | | (0.2) | | (0.4) |
| | | $ | - | $ | 0.9 |

### 4. PROVISION ON LONG-LIVED ASSETS

In first quarter 2014 AltaGas recorded a provision of $19.6 million on its Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and $18.7 million 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 US 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$0.7 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 | **June 30 2015** | December 31 2014 |
|---|---|---|
| Natural gas held in storage | **$ 95.7** | $ 136.7 |
| Other inventory | **19.5** | 18.6 |
| | **$ 115.2** | $ 155.3 |

## 7. GOODWILL

| As at | **June 30 2015** | December 31 2014 |
|---|---|---|
| Balance, beginning of period | **$ 785.1** | $ 743.1 |
| Foreign exchange translation | **38.0** | 42.0 |
| | **$ 823.1** | $ 785.1 |

## 8. LONG-TERM DEBT

| As at | Maturity date | **June 30 2015** | December 31 2014 |
|---|---|---|---|
| Credit facilities | | | |
| $1,400 million unsecured extendible revolving[(a)] | 15-Dec-2018 | **$ 38.7** | $ - |
| Medium-term notes (MTNs) | | | |
| $200 million Senior unsecured - 5.49 percent | 27-Mar-2017 | **200.0** | 200.0 |
| $175 million Senior unsecured - 4.60 percent | 15-Jan-2018 | **175.0** | 175.0 |
| $200 million Senior unsecured - 4.55 percent | 17-Jan-2019 | **200.0** | 200.0 |
| $200 million Senior unsecured - 4.07 percent | 01-Jun-2020 | **200.0** | 200.0 |
| $350 million Senior unsecured - 3.72 percent | 28-Sep-2021 | **350.0** | 350.0 |
| $300 million Senior unsecured - 3.57 percent | 12-Jun-2023 | **300.0** | 300.0 |
| $200 million Senior unsecured - 4.40 percent | 15-Mar-2024 | **200.0** | 200.0 |
| $300 million Senior unsecured - 3.84 percent | 15-Jan-2025 | **299.9** | 300.0 |
| $100 million Senior unsecured - 5.16 percent | 13-Jan-2044 | **100.0** | 100.0 |
| $300 million Senior unsecured - 4.50 percent | 15-Aug-2044 | **299.7** | 299.7 |
| US$175 million Senior unsecured - floating[(b)] | 13-Apr-2015 | **-** | 203.0 |
| US$200 million Senior unsecured - floating[(c)] | 24-Mar-2016 | **249.5** | 232.1 |
| US$125 million Senior unsecured - floating[(d)] | 17-Apr-2017 | **155.9** | - |
| SEMCO long-term debt | | | |
| US$300 million SEMCO Senior secured - 5.15 percent[(e)] | 21-Apr-2020 | **374.2** | 348.0 |
| US$82 million SEMCO Senior secured - 4.48 percent | 2-Mar-2032 | **99.4** | 95.1 |
| Debenture notes | | | |
| PNG RoyNat Debenture - 3.50 percent[(f)] | 15-Sep-2017 | **9.2** | 9.8 |
| PNG 2018 Series Debenture - 8.75 percent[(f)] | 15-Nov-2018 | **10.0** | 10.0 |
| PNG 2024 CFI Debenture - 7.39 percent[(g)] | 01-Nov-2024 | **7.2** | 7.4 |
| PNG 2025 Series Debenture - 9.30 percent[(f)] | 18-Jul-2025 | **14.5** | 14.5 |
| PNG 2027 Series Debenture - 6.90 percent[(f)] | 02-Dec-2027 | **15.5** | 15.5 |
| Loan from Province of Nova Scotia [(h)] | 31-Jul-2017 | **2.2** | 2.1 |
| CINGSA capital lease - 3.50 percent | 1-May-2040 | **0.5** | 0.5 |
| CINGSA capital lease - 4.48 percent | 4-Jun-2068 | **0.2** | 0.2 |
| Promissory notes | 25-Oct-2015 | **0.5** | 1.0 |
| Other long-term debt | | **-** | 0.1 |
| | | **3,302.1** | 3,264.0 |
| Less current portion | | **260.7** | 214.4 |
| | | **$ 3,041.4** | $ 3,049.6 |

(a) Borrowings on the facility can be by way of prime loans, US 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 note 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.

## 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 Values of Financial Instruments**

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.

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

*Short-term investments, Accounts Receivable, Accounts Payable, Short-term debt and Dividends Payable* - the carrying amount approximates fair value because of the short maturity of these instruments.

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

| Summary of Fair Values | | June 30 2015 | | December 31 2014 |
|---|---|---|---|---|
| Current portion of long-term debt | | | | |
| Carrying amount | **$** | **260.7** | $ | 214.4 |
| Fair value of current portion of long-term debt | **$** | **261.3** | $ | 214.4 |

| Summary of Fair Values | | June 30 2015 | | December 31 2014 |
|---|---|---|---|---|
| Long-term debt | | | | |
| Carrying amount | **$** | **3,041.4** | $ | 3,049.6 |
| Fair value of long-term debt | **$** | **3,180.9** | $ | 3,170.3 |

| Summary of Fair Values | | June 30 2015 | | December 31 2014 |
|---|---|---|---|---|
| Long-term liabilities excluding non-financial liabilities | | | | |
| Carrying amount *(note 10)* | **$** | **158.8** | $ | 155.6 |
| Fair value of long-term liabilities | **$** | **150.4** | $ | 149.1 |

**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.

| **June 30, 2015** | | Level 1 | | Level 2 | Level 3 | | Total |
|---|---|---|---|---|---|---|---|
| Financial assets | | | | | | | |
| Cash and cash equivalents | **$** | **289.6** | | **-** | **-** | **$** | **289.6** |
| Risk management assets - current | | **-** | **$** | **63.3** | **-** | **$** | **63.3** |
| Risk management assets - non-current | | **-** | **$** | **21.3** | **-** | **$** | **21.3** |
| Long-term investments and other assets (1) | **$** | **42.4** | | **-** | **-** | **$** | **42.4** |
| Financial liabilities | | | | | | | |
| Risk management liabilities - current | | **-** | **$** | **50.2** | **-** | **$** | **50.2** |
| Risk management liabilities - non-current | | **-** | **$** | **26.8** | **-** | **$** | **26.8** |
| Current portion of long-term debt | | **-** | **$** | **261.3** | **-** | **$** | **261.3** |
| Long-term debt | | **-** | **$** | **3,180.9** | **-** | **$** | **3,180.9** |
| Other long-term liabilities (2) | | **-** | **$** | **150.4** | **-** | **$** | **150.4** |
| December 31, 2014 | | Level 1 | | Level 2 | Level 3 | | Total |
| Financial assets | | | | | | | |
| Cash and cash equivalents | $ | 371.0 | | - | - | $ | 371.0 |
| Short-term investment | $ | 50.0 | | - | - | $ | 50.0 |
| Risk management assets - current | | - | $ | 70.8 | - | $ | 70.8 |
| Risk management assets - non-current | | - | $ | 21.1 | - | $ | 21.1 |
| Long-term investments and other assets (1) | $ | 46.3 | | - | - | $ | 46.3 |
| Financial liabilities | | | | | | | |
| Risk management liabilities - current | | - | $ | 43.5 | - | $ | 43.5 |
| Risk management liabilities - non-current | | - | $ | 14.7 | - | $ | 14.7 |
| Current portion of long-term debt | | - | $ | 214.4 | - | $ | 214.4 |
| Long-term debt | | - | $ | 3,170.3 | - | $ | 3,170.3 |
| Other long-term liabilities (2) | | - | $ | 149.1 | - | $ | 149.1 |

(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 June 30 2015 | Three months ended June 30 2014 | Six months ended June 30 2015 | Six months ended June 30 2014 |
|---|---|---|---|---|
| Natural gas | **$ 1.5** | $ 4.0 | **$ 3.0** | $ (1.0) |
| Storage optimization | **-** | (1.1) | **(0.9)** | 0.8 |
| NGL frac spread | **4.2** | (0.1) | **7.6** | (0.9) |
| Power | **(27.8)** | 0.1 | **(18.5)** | (1.5) |
| Heat rate | **(0.7)** | (0.1) | **(0.9)** | (0.3) |
| Foreign exchange | **0.2** | - | **0.4** | 0.1 |
| Embedded derivative | **-** | - | **0.1** | - |
| | **$ (22.6)** | $ 2.8 | **$ (9.2)** | $ (2.8) |

**Offsetting of Derivative Assets and Derivative Liabilities**

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

**As at June 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 | **$ 84.4** | **$ 42.2** | **$ 42.2** |
| Storage Optimization | **0.2** | **0.1** | **0.1** |
| NGL frac spread | **13.8** | **-** | **13.8** |
| Power | **28.5** | **-** | **28.5** |
| | **$ 126.9** | **$ 42.3** | **$ 84.6** |
| Risk management liabilities [(2)] | | | |
| Natural Gas | **$ 85.4** | **$ 42.2** | **$ 43.2** |
| Storage Optimization | **0.2** | **0.1** | **0.1** |
| NGL frac spread | **2.9** | **-** | **2.9** |
| Power | **30.2** | **-** | **30.2** |
| Heat rate | **0.6** | **-** | **0.6** |
| Total | **$ 119.3** | **$ 42.3** | **$ 77.0** |

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $63.3 and risk management assets (non-current) balance of $21.3.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $50.2 and risk management liabilities (non-current) balance of $26.8.*

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 June 30, 2015, AltaGas designated US$356 million of outstanding debt as a net investment hedge of its US subsidiaries (December 31, 2014 - US$375 million). For the three and six months ended June 30, 2015, AltaGas incurred after-tax unrealized gain of $5.7 million and unrealized loss of $29.7 million, respectively, arising from the translation of debt in OCI (2014 - after-tax unrealized gain of $18.7 million and unrealized loss of $2.0 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 $10.8 million and other long-term liabilities for $158.8 million as at June 30, 2015. Accretion expenses for the three and six months ended June 30, 2015 were $1.7 million and $3.4 million respectively (June 30, 2014 - $nil). 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.

| 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 for cash on exercise of options | 418,156 | | 11.6 |
| Shares issued under DRIP | 1,088,278 | | 42.8 |
| **Issued and outstanding at June 30, 2015** | **135,448,183** | **$** | **2,814.3** |

| 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 |
| **Issued and outstanding at June 30, 2015** | **8,000,000** | **$** | **195.9** |

| 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 June 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 June 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 June 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 June 30, 2015, 8,754,445 shares were reserved for issuance under the plan. As at June 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 June 30, 2015, unexpensed fair value of share option compensation cost associated with future periods was $3.8 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 | 187,500 | 40.87 |
| Exercised | (418,156) | 25.09 |
| Expired | (3,750) | 38.63 |
| Forfeited | (98,876) | 34.81 |
| **Share options outstanding, June 30, 2015** | **4,790,373** | **$ 31.05** |
| **Share options exercisable, June 30, 2015** | **2,778,561** | **$ 25.98** |

[1] *Weighted average.*

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

| | Options outstanding | | | Options exercisable | |
|---|---|---|---|---|---|
| | Number outstanding | Weighted average exercise price | Weighted average remaining contractual life | Number exercisable | Exercise price |
| $14.24 to $18.00 | 263,000 | $ 15.14 | 3.79 | 263,000 | $ 15.14 |
| $18.01 to $25.08 | 963,925 | 20.72 | 4.84 | 963,925 | 20.72 |
| $25.09 to $50.89 | 3,563,448 | 35.02 | 5.88 | 1,551,636 | 31.09 |
| | **4,790,373** | **$ 31.05** | **5.56** | **2,778,561** | **$ 25.98** |

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

AltaGas' MTIP for employees and executive officers include 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 employee.

For the three and six months ended June 30, 2015, the compensation expense recorded for the MTIP was $0.8 million and $2.2 million, respectively (three months and six months ended June 30, 2014 - $1.6 million and $2.8 million, respectively). As at June 30, 2015, the unrecognized compensation expense relating to the remaining vesting period was $14.2 million (December 31, 2014 - $11.7 million).

## 12. NET INCOME (LOSS) PER COMMON SHARES

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

| | Three months ended | | Six months ended | |
|---|---|---|---|---|
| | **June 30 2015** | June 30 2014 | **June 30 2015** | June 30 2014 |
| Numerator: | | | | |
| Net income (loss) applicable to controlling interests | **$ (11.9)** | $ 36.3 | **$ 64.4** | $ 83.6 |
| Less: Preferred share dividends | **(10.1)** | (7.4) | **(20.2)** | (14.8) |
| Net income (loss) per common shares | **$ (22.0)** | $ 28.9 | **$ 44.2** | $ 68.8 |
| Denominator: | | | | |
| *(millions)* | | | | |
| Weighted average number of common shares outstanding | **135.0** | 123.3 | **134.6** | 122.9 |
| Dilutive equity instruments[1] | **-** | 2.1 | **1.3** | 2.0 |
| Weighted average number of common shares outstanding - diluted | **135.0** | 125.4 | **135.9** | 124.9 |
| Basic net income (loss) per common share | **$ (0.16)** | $ 0.23 | **$ 0.33** | $ 0.56 |
| Diluted net income (loss) per common share | **$ (0.16)** | $ 0.23 | **$ 0.33** | $ 0.55 |

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

For the three and six months ended June 30, 2015, 4.8 million and 0.8 million of share options, (2014 - 0.1 million for both periods) respectively were excluded from the diluted net loss 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 $208.7 million payable over the next 19 years, of which $50.7 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 $10.9 million over the next 7 years, of which $7.8 million is payable in the next five years.

### 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 US 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 the AUC Loss Hearings for 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 June 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 and other factors affecting the payment of future benefits.

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

| | Canada | | United States | | Total | |
|---|---|---|---|---|---|---|
| **Three months ended June 30, 2015** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** |
| Current service cost | $ 1.7 | $ 0.2 | $ 1.9 | $ 0.5 | $ 3.6 | $ 0.7 |
| Interest cost | 1.3 | 0.1 | 2.5 | 0.8 | 3.8 | 0.9 |
| Expected return on plan assets | (1.3) | - | (3.5) | (1.1) | (4.8) | (1.1) |
| Amortization of net actuarial loss | 0.5 | - | - | - | 0.5 | - |
| Amortization of regulatory asset | 0.4 | - | 1.0 | 0.2 | 1.4 | 0.2 |
| Net benefit cost recognized | $ 2.6 | $ 0.3 | $ 1.9 | $ 0.4 | $ 4.5 | $ 0.7 |

| | Canada | | United States | | Total | |
|---|---|---|---|---|---|---|
| **Six months ended June 30, 2015** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** |
| Current service cost | $ 3.5 | $ 0.3 | $ 3.7 | $ 1.0 | $ 7.2 | $ 1.3 |
| Interest cost | 2.6 | 0.3 | 5.1 | 1.7 | 7.7 | 2.0 |
| Expected return on plan assets | (2.6) | (0.1) | (7.1) | (2.2) | (9.7) | (2.3) |
| Amortization of net actuarial loss | 1.0 | - | - | - | 1.0 | - |
| Amortization of regulatory asset | 0.7 | - | 2.1 | 0.3 | 2.8 | 0.3 |
| Net benefit cost recognized | $ 5.2 | $ 0.5 | $ 3.8 | $ 0.8 | $ 9.0 | $ 1.3 |

| Three months ended June 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 |

| Six months ended June 30, 2014 | Canada | | United States | | Total | |
|---|---|---|---|---|---|---|
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 2.9 | $ 0.3 | $ 2.7 | $ 0.7 | $ 5.6 | $ 1.0 |
| Interest cost | 2.6 | 0.3 | 4.6 | 1.5 | 7.2 | 1.8 |
| Expected return on plan assets | (2.3) | (0.1) | (6.1) | (1.9) | (8.4) | (2.0) |
| Amortization of past service cost | - | - | - | (0.1) | - | (0.1) |
| Amortization of net actuarial loss | 0.3 | - | 0.4 | 0.1 | 0.7 | 0.1 |
| Amortization of regulatory asset | 0.4 | - | 0.9 | 0.2 | 1.3 | 0.2 |
| Net benefit cost recognized | $ 3.9 | $ 0.5 | $ 2.5 | $ 0.5 | $ 6.4 | $ 1.0 |

**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 three and six months ended June 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 six months ended June 30, 2015 was $6.8 million and $25.5 million, respectively (2014 - $0.8 million and $8.5 million).

**16. SEASONALITY**

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

The power generation in the run-of-river hydro-projects 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.

**17. SEGMENTED INFORMATION**

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

| | |
|---|---|
| **Gas** | – NGL processing and extraction plants;<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;<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 June 30, 2015 (unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 177.4 | $ 104.1 | $ 179.9 | - | $ (22.7) | $ 438.7 |
| Unrealized loss on risk management | - | - | - | (22.6) | - | (22.6) |
| Cost of sales | (97.3) | (56.8) | (86.8) | - | 21.6 | (219.3) |
| Operating and administrative | (43.7) | (18.1) | (53.8) | (6.2) | 1.1 | (120.7) |
| Accretion expenses | (0.9) | (1.8) | - | - | - | (2.7) |
| Depreciation, depletion and amortization | (15.3) | (14.5) | (18.3) | (1.7) | - | (49.8) |
| Income from equity investments | 0.3 | 4.9 | 0.1 | - | - | 5.3 |
| Other income | - | - | 1.1 | 1.3 | - | 2.4 |
| Foreign exchange loss | - | - | - | (0.8) | - | (0.8) |
| Interest expense | - | - | - | (30.4) | - | (30.4) |
| Income (loss) before income taxes | $ 20.5 | $ 17.8 | $ 22.2 | $ (60.4) | - | $ 0.1 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 49.5 | $ 44.3 | $ 47.6 | $ 1.4 | - | $ 142.8 |
| Intangible assets | $ 1.0 | $ 0.1 | $ 0.7 | $ 4.2 | - | $ 6.0 |

| Six months ended June 30, 2015 (unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 462.1 | $ 214.3 | $ 610.8 | - | $ (117.4) | $ 1,169.8 |
| Unrealized loss on risk management | - | - | - | (9.2) | - | (9.2) |
| Cost of sales | (291.8) | (117.2) | (358.0) | - | 114.5 | (652.5) |
| Operating and administrative | (86.3) | (31.9) | (110.4) | (12.4) | 2.9 | (238.1) |
| Accretion expenses | (1.8) | (3.6) | - | - | - | (5.4) |
| Depreciation, depletion and amortization | (30.4) | (29.1) | (36.8) | (3.3) | - | (99.6) |
| Income from equity investments | (1.7) | 0.4 | 0.9 | - | - | (0.4) |
| Other income | - | - | 1.5 | 2.7 | - | 4.2 |
| Foreign exchange gain | - | - | - | 0.4 | - | 0.4 |
| Interest expense | - | - | - | (60.2) | - | (60.2) |
| Income (loss) before income taxes | $ 50.1 | $ 32.9 | $ 108.0 | $ (82.0) | - | $ 109.0 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 71.1 | $ 109.3 | $ 70.5 | $ 1.8 | - | $ 252.7 |
| Intangible assets | $ 1.1 | $ 9.3 | $ 1.1 | $ 10.0 | - | $ 21.5 |
| As at June 30, 2015 | | | | | | |
| Goodwill | 161.4 | - | 661.7 | - | - | $ 823.1 |
| Segmented assets | $ 2,316.6 | $ 2,521.8 | $ 3,110.7 | $ 545.7 | - | $ 8,494.8 |

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

(2) *Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on US assets.*

| Three months ended June 30, 2014 (unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 259.8 | $ 77.6 | $ 172.9 | - | $ (41.9) | $ 468.4 |
| Unrealized gain on risk management | - | - | - | 2.8 | - | 2.8 |
| Cost of sales | (161.9) | (48.0) | (90.6) | - | 40.3 | (260.2) |
| Operating and administrative | (45.6) | (11.0) | (47.3) | (7.6) | 1.6 | (109.9) |
| Accretion expenses | (0.9) | (0.1) | - | - | - | (1.0) |
| Depreciation, depletion and amortization | (16.7) | (8.5) | (15.9) | (0.7) | - | (41.8) |
| Income from equity investments | 4.1 | 3.1 | 0.1 | - | - | 7.3 |
| Other income | 0.6 | (0.2) | 0.9 | 0.3 | - | 1.6 |
| Foreign exchange loss | - | - | - | (0.2) | - | (0.2) |
| Interest expense | - | - | - | (23.0) | - | (23.0) |
| Income (loss) before income taxes | $ 39.4 | $ 12.9 | $ 20.1 | $ (28.4) | - | $ 44.0 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ 7.9 | $ 86.9 | $ 36.7 | $ 0.6 | - | $ 132.1 |
| Intangible assets | - | - | $ 0.5 | $ 3.9 | - | $ 4.4 |

| Six months ended June 30, 2014 (unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination[1] | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 651.5 | $ 181.3 | $ 616.7 | $ - | $ (151.7) | $ 1,297.8 |
| Unrealized loss on risk management | - | - | - | (2.8) | - | (2.8) |
| Cost of sales | (452.3) | (123.0) | (386.7) | - | 147.5 | (814.5) |
| Operating and administrative | (91.0) | (23.6) | (99.1) | (14.3) | 4.2 | (223.8) |
| Accretion expenses | (1.9) | (0.2) | - | - | - | (2.1) |
| Depreciation, depletion and amortization | (33.6) | (16.1) | (31.8) | (1.5) | - | (83.0) |
| Provision on long-lived assets | (38.3) | (10.9) | - | - | - | (49.2) |
| Income from equity investments | 13.4 | 10.5 | 0.7 | - | - | 24.6 |
| Other income (expenses) | 12.0 | (0.1) | 1.4 | (1.9) | - | 11.4 |
| Foreign exchange gain | - | - | - | 0.2 | - | 0.2 |
| Interest expense | - | - | - | (48.3) | - | (48.3) |
| Income (loss) before income taxes | $ 59.8 | $ 17.9 | $ 101.2 | $ (68.6) | - | $ 110.3 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[2] | $ (5.9) | $ 167.2 | $ 56.3 | $ 2.7 | - | $ 220.3 |
| Intangible assets | $ 0.2 | - | $ 0.8 | $ 7.3 | - | $ 8.3 |
| As at June 30, 2014 | | | | | | |
| Goodwill | $ 161.4 | - | $ 583.4 | - | - | $ 744.8 |
| Segmented assets | $ 2,329.9 | $ 2,062.9 | $ 2,682.5 | $ 122.1 | - | $ 7,197.4 |

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

(2) *Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on US assets.*

# Supplementary Quarterly Financial Information
(unaudited)

| **FINANCIAL HIGHLIGHTS**[1]<br>*($ millions unless otherwise indicated)* | **Q2-15** | Q1-15 | Q4-14 | Q3-14 | Q2-14 |
|---|---|---|---|---|---|
| Net Revenue[2] | | | | | |
| Gas | **$ 80.4** | $ 88.3 | $ 97.5 | $ 102.6 | $ 102.6 |
| Power | **52.2** | 45.3 | 72.7 | 43.0 | 32.6 |
| Utilities | **94.3** | 160.9 | 125.2 | 72.5 | 83.2 |
| Corporate | **(21.3)** | 14.7 | (8.7) | 1.3 | 3.1 |
| Intersegment Elimination | **(1.1)** | (1.8) | (1.6) | (2.0) | (1.5) |
| | **$ 204.5** | $ 307.4 | $ 285.1 | $ 217.4 | $ 220.0 |
| EBITDA[2] | | | | | |
| Gas | **$ 36.7** | $ 45.7 | $ 58.1 | $ 55.8 | $ 57.1 |
| Power | **34.1** | 31.6 | 56.5 | 30.7 | 21.6 |
| Utilities | **40.5** | 104.4 | 73.9 | 23.6 | 35.8 |
| Corporate | **(4.8)** | (4.8) | (24.2) | (6.3) | (7.3) |
| | **$ 106.5** | $ 176.9 | $ 164.3 | $ 103.8 | $ 107.2 |
| Operating Income (Loss)[2] | | | | | |
| Gas | **$ 20.5** | $ 29.6 | $ (29.5) | $ 38.3 | $ 39.5 |
| Power | **17.8** | 15.1 | 42.2 | 19.3 | 13.0 |
| Utilities | **22.2** | 85.9 | 57.2 | 7.8 | 19.9 |
| Corporate | **(6.6)** | (6.4) | (25.4) | (7.1) | (8.0) |
| | **$ 53.9** | $ 124.2 | $ 44.5 | $ 58.3 | $ 64.4 |
| Normalized Operating Income (Loss)[2] | | | | | |
| Gas | **$ 21.2** | $ 30.8 | $ 40.8 | $ 39.0 | $ 40.0 |
| Power | **18.0** | 15.2 | 16.0 | 19.4 | 13.2 |
| Utilities | **22.2** | 85.9 | 57.2 | 7.8 | 19.9 |
| Corporate | **(7.4)** | (6.9) | (8.9) | (6.9) | (8.6) |
| | **$ 54.0** | $ 125.0 | $ 105.1 | $ 59.3 | $ 64.5 |

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

(2) *Non-GAAP financial measure.*

# Supplementary Quarterly Operating Information

(unaudited)

| | **Q2-15** | Q1-15 | Q4-14 | Q3-14 | Q2-14 |
|---|---|---|---|---|---|
| **OPERATING HIGHLIGHTS** | | | | | |
| **GAS** | | | | | |
| Total inlet gas processed (Mmcf/d)(1) | **1,123** | 1,498 | 1,551 | 1,447 | 1,476 |
| Extraction volumes (Bbls/d)(1) (2) | **49,288** | 73,293 | 76,203 | 72,969 | 69,867 |
| Frac spread - realized ($/Bbl)(1) (3) | **20.58** | 11.43 | 16.29 | 14.19 | 17.31 |
| Frac spread - average spot price ($/Bbl)(1)(4) | **2.51** | 3.72 | 11.18 | 16.58 | 18.14 |
| **POWER** | | | | | |
| Volume of power sold (GWh)(1) | **1,287** | 1,449 | 1,457 | 1,464 | 1,067 |
| Average Alberta realized power price ($/MWh)(1) | **48.16** | 45.42 | 48.85 | 67.69 | 51.74 |
| Average price realized on sale of power ($/MWh)(1) (5) | **68.18** | 54.62 | 63.77 | 74.51 | 55.92 |
| Alberta Power Pool average spot price ($/MWh)(1) | **57.22** | 29.02 | 30.47 | 64.34 | 42.43 |
| **UTILITIES** | | | | | |
| Canadian utilities | | | | | |
| Natural gas deliveries - end-use (PJ)(6) | **5.2** | 13.0 | 10.6 | 3.1 | 6.2 |
| Natural gas deliveries - transportation (PJ)(6) | **1.5** | 1.9 | 1.4 | 1.0 | 1.2 |
| US utilities | | | | | |
| Natural gas deliveries end use (Bcf) (6) | **10.0** | 32.1 | 23.1 | 6.1 | 10.6 |
| Natural gas deliveries transportation (Bcf) (6) | **10.0** | 13.7 | 11.7 | 8.5 | 8.4 |
| Service sites(7) | **560,755** | 564,173 | 562,746 | 554,837 | 553,320 |
| Degree day variance from normal - AUI (%)(8) | **(9.7)** | (11.3) | (3.1) | (6.2) | 10.8 |
| Degree day variance from normal - Heritage Gas (%)(8) | **14.7** | 15.7 | (8.4) | (1.5) | 3.7 |
| Degree day variance from normal - SEMCO Gas (%)(9) | **(1.7)** | 16.4 | 5.1 | 44.7 | 9.9 |
| Degree day variance from normal - ENSTAR (%)(9) | **(17.4)** | (8.0) | (10.5) | (8.3) | (7.7) |

*(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 US 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 US 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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