AltaGas

NEWS RELEASE
ALTAGAS REPORTS THIRD QUARTER RESULTS

Calgary, Alberta (October 30, 2014)

Highlights
- $16.6 million in normalized net income and $104.9 million in normalized EBITDA;
- $79.9 million in normalized funds from operations;
- Commissioned Forrest Kerr, the largest project in AltaGas' history; and
- 15-year strategic alliance signed with Painted Pony Petroleum Ltd.

AltaGas Ltd. ("AltaGas") (TSX:ALA) today reported third quarter normalized net income of $16.6 million ($0.13 per share), compared to $24.7 million ($0.21 per share) in the same period 2013. Normalized EBITDA was $104.9 million for the third quarter 2014, compared to $103.5 million for the same period 2013. Normalized funds from operations were $79.9 million ($0.63 per share) for the third quarter 2014, compared to $80.2 million ($0.68 per share) for the same period 2013.

"We continue to deliver on our growth plans and have built out a very competitive service offering to connect producers from well head to new markets through energy exports," said David Cornhill, Chairman and CEO of AltaGas. "The strategic alliance we signed with Painted Pony in the quarter is a direct result and we continue to discuss opportunities with other producers. In October we also reached a significant milestone as we completed Forrest Kerr, the largest project in our history."

In the third quarter, earnings and cash flow were driven primarily by higher natural gas volumes processed, ownership of Petrogas, and small contributions from Forrest Kerr. These positive earnings contributions in the quarter were more than offset by the lower contribution from Alberta power assets, compared to the third quarter 2013.

On a GAAP basis, net income applicable to common shares was $16.6 million ($0.13 per share) for the three months ended September 30, 2014, compared to $43.3 million ($0.36 per share) for the same period 2013. Third quarter 2013 included one-time after-tax net gains related to assets of $18.7 million.

In the third quarter, AltaGas signed definitive agreements with Painted Pony Petroleum Ltd. to enter into a 15-year strategic alliance for the development of processing infrastructure and marketing services for natural gas and natural gas liquids. In the first phase of the strategic alliance, AltaGas plans to construct and operate the Townsend Facility, a 198 Mmcf/d shallow-cut gas processing facility in the Montney area. Painted Pony will maintain the right to a minimum 150 Mmcf/d of firm capacity in the Townsend Facility.

For the nine months ended September 30, 2014, normalized net income increased to $117.0 million compared to $116.0 million for the same period in 2013. Normalized earnings per share were $0.94 compared to $1.02 per share for the same period in 2013. Normalized funds from operations increased 13 percent to $315.6 million ($2.54 per share), compared to $279.3 million ($2.45 per share) for the same period in 2013. Normalized EBITDA increased 10 percent to $391.6 million compared to $355.6 million for the same period in 2013.

On a GAAP basis, net income applicable to common shares was $85.4 million ($0.69 per share) for the nine months ended September 30, 2014, compared to $128.2 million ($1.12 per share) for the same period 2013. Net income applicable to common shares for the nine months ended September 30, 2014 was normalized for provisions taken for certain assets, impact from the sale of non-core assets, unrealized gain or loss on risk management contracts, unrealized gain or loss on long-term investments, the cost of early redemption of medium-term notes, and costs incurred for the energy export projects. Net income applicable to common shares for nine months ended September 30, 2013 was normalized for similar one-time items as in year-to-date 2014, excluding the costs associated with the early redemption of medium-term notes in 2014, as well as the impact of statutory tax rate changes in 2013.

Northwest Run-of-River Projects

On July 30, 2014, AltaGas announced the start-up of its 195 MW Forrest Kerr run-of-river hydro project. Commissioning of the powerhouse systems and high voltage switchyard were completed in July and the facility was tied-in and started delivering power to the Northwest Transmission Line (NTL). Significant transmission line constraints on the NTL combined with a flooding event on the Iskut River led to delays in contractual Commercial Operations Date (COD) for Forrest Kerr. The final test runs for COD were initiated on October 16, 2014. A number of online electrical and system functional checks were then performed and a certificate of COD was delivered to BC Hydro on October 21, 2014.

At the 16 MW Volcano Creek project, construction continues to pace ahead of schedule. Major construction is complete and final commissioning is well underway. The project is on track to be in service in the fourth quarter 2014.

At the 66 MW McLymont Creek project, construction of the powerhouse foundation continues to advance ahead of schedule. Installation of the turbines is underway and excavation of the 2,800 meter power tunnel is approximately 90 percent complete. Construction of the intake access road is nearing completion and intake construction is expected to commence in November. The project is expected to be in service in mid-2015.

Energy Exports

AltaGas continues to advance its Liquefied Petroleum Gas (LPG) export initiatives. AltaGas is operating Petrogas' Ferndale facility in the State of Washington, which sent two cargoes of LPG to Asia in the third quarter. Export capacity at the Ferndale facility is expected to ramp up to 30,000 Bbls/d over the next several years.

AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) continues to make progress on building an LPG export business off Canada's west coast for an additional 30,000 Bbls/d. AIJVLP has been in active negotiations for potential site locations.

In addition to LPG, AIJVLP is working with various parties to support the Companies' Creditors Arrangement Act (CCAA) Plan of Arrangement proceedings for the Douglas Channel LNG project. On October 29, 2014, the Supreme Court of British Columbia (the "Court") approved the Plan of Arrangement for filing and distribution to creditors. Creditors are to review the Plan of Arrangement and vote on it. With a positive vote, the Plan of Arrangement will proceed to be sanctioned by the Court and become effective thereafter, upon satisfying other conditions prescribed in the Plan of Arrangement including finalization of transaction documents and approval of the PNG agreement from the British Columbia Utilities Commission.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- The Board of Directors approved the November 2014 dividend of $0.1475 per common share. The dividend will be paid on December 15, 2014, to common shareholders of record on November 25, 2014. The ex-dividend date is November 21, 2014. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing October 1, 2014, and ending December 31, 2014, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on December 31, 2014 to shareholders of record on December 16, 2014. The ex-dividend date is December 12, 2014;

- The Board of Directors approved a dividend of US$0.275 per share for the period commencing October 1, 2014, and ending December 31, 2014, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on December 31, 2014 to shareholders of record on December 16, 2014. The ex-dividend date is December 12, 2014;
- The Board of Directors also approved a dividend of $0.3125 per share for the period commencing October 1, 2014, and ending December 31, 2014, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on December 31, 2014 to shareholders of record on December 16, 2014. The ex-dividend date is December 12, 2014; and
- The Board of Directors also approved a dividend of $0.296875 per share for the period commencing October 1, 2014, and ending December 31, 2014, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on December 31, 2014 to shareholders of record on December 16, 2014. The ex-dividend date is December 12, 2014.

CONFERENCE CALL AND WEBCAST DETAILS:

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

Members of the media, investment communities and other interested parties may dial (416) 340-8527 or call toll free at 1-866-852-2121. 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 4662646. The replay expires at midnight (Eastern) on November 6, 2014.

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 nine months ended September 30, 2014, compared to the three and nine months ended September 30, 2013. This MD&A dated October 29, 2014, should be read in conjunction with the accompanying unaudited interim condensed Consolidated Financial Statements and notes thereto of AltaGas as at, and for the three and nine months ended September 30, 2014, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2013.

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: "Consolidated 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 the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas 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 (U.S.) Inc.

THIRD QUARTER HIGHLIGHTS [1]

- Normalized funds from operations was $79.9 million, compared to $80.2 million in third quarter 2013;
- Normalized EBITDA was $104.9 million, compared to $103.5 million in third quarter 2013;
- Debt-to-total capitalization ratio was 44.3 percent as at September 30, 2014, compared to 54.7 percent as at September 30, 2013, and 53.1 percent as at December 31, 2013;
- Completed Forrest Kerr, the largest project in the Corporations' history on time and on budget generating power in July despite a delay in the in-service date of the Northwest Transmission Line (NTL);
- Entered into a 15-year strategic alliance with Painted Pony Petroleum Ltd. (Painted Pony) for the development of processing infrastructure and marketing services for natural gas and natural gas liquids (NGL);
- Completed commercial agreements for the 198 Mmcf/d shallow-cut gas processing facility (Townsend Facility);
- Completed construction on the 16 MW Volcano Creek project (Volcano);
- Issued 8,000,000 five-year rate-reset Series G Preferred Shares at a price of $25 per Series G Preferred Share for aggregate gross proceeds of $200 million, including 2,000,000 Series G Preferred Shares pursuant to the exercise in full of an underwriters' option;
- On August 15, 2014, issued $300 million of 30-year senior unsecured medium-term notes (MTNs). The notes carry a coupon rate of 4.50 percent and mature on August 15, 2044;
- On August 19, 2014 AltaGas subscribed, on a private placement basis, to 4,166,666 Common Shares of Painted Pony, at a price of $12 per Common Share for total consideration of approximately $50 million; and
- On August 28, 2014, issued 9,027,500 Common Shares at a price of $51 per Common Share for aggregate gross proceeds of $460 million, including 1,177,500 Common Shares pursuant to the exercise in full of an underwriters' option.

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

CONSOLIDATED FINANCIAL REVIEW

(unaudited) *($ millions)*	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Revenue	**444.2**	389.7	**1,739.2**	1,461.8
Net revenue[(1)]	**217.4**	246.6	**733.9**	695.6
Normalized operating income[(1)]	**59.3**	63.5	**260.9**	240.7
Normalized EBITDA[(1)]	**104.9**	103.5	**391.6**	355.6
Net income applicable to common shares	**16.6**	43.3	**85.4**	128.2
Normalized net income[(1)]	**16.6**	24.7	**117.0**	116.0
Total assets	**8,142.0**	6,722.5	**8,142.0**	6,722.5
Total long-term liabilities	**3,990.2**	3,368.0	**3,990.2**	3,368.0
Net additions to property, plant and equipment	**200.9**	85.6	**422.6**	921.2
Dividends declared[(2)]	**56.2**	45.1	**155.2**	126.9
Cash flows				
Normalized funds from operations[(1)]	**79.9**	80.2	**315.6**	279.3

($ per share, except shares outstanding)	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Normalized EBITDA[(1)]	**0.83**	0.87	**3.15**	3.12
Net income - basic	**0.13**	0.36	**0.69**	1.12
Net income - diluted	**0.13**	0.35	**0.68**	1.09
Normalized net income[(1)]	**0.13**	0.21	**0.94**	1.02
Dividends declared[(2)]	**0.44**	0.38	**1.25**	1.11
Cash flows				
Normalized funds from operations[(1)]	**0.63**	0.68	**2.54**	2.45
Shares outstanding - basic (millions)				
During the period[(3)]	**127.1**	118.7	**124.3**	114.1
End of period	**133.1**	118.9	**133.1**	118.9

(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 of $0.125 beginning April 24, 2013, $0.1275 beginning July 31, 2013 and $0.1475 beginning on May 26, 2014.*

(3) *Weighted average.*

Three Months Ended September 30

Normalized net income was $16.6 million ($0.13 per share) for third quarter 2014, compared to $24.7 million ($0.21 per share) reported for same quarter 2013. The decrease in earnings in third quarter 2014 compared to same quarter 2013 was primarily a result of lower contribution from Alberta power assets, higher compensation costs, increased preferred share dividends, higher interest expense, and higher operating expenses. The decrease was partially offset by higher revenues due to higher volumes processed at the Harmattan, Gordondale and Blair Creek facilities, the earnings contribution from Petrogas Energy Corp. (Petrogas), a decreased tax expense due to lower taxable earnings, contributions from Forrest Kerr coming into service in third quarter 2014, and continued customer and rate base growth at the utilities.

Net income applicable to common shares for third quarter 2014 was $16.6 million ($0.13 per share), compared to $43.3 million ($0.36 per share) for same quarter 2013. Results were impacted by the items described above as well as the gain on the sale of Pacific Trail Pipelines Limited Partnership (PTP) and provisions taken for certain non-core gas and utility assets in third quarter 2013. Net income applicable to common shares for third quarter 2014 was normalized for after-tax amounts related to the unrealized gain on risk management contracts, unrealized loss on long-term investments, transaction costs related to acquisitions, and development costs incurred for the energy export projects.

Normalized funds from operations for third quarter 2014 was $79.9 million ($0.63 per share), compared to $80.2 million ($0.68 per share) for same quarter 2013. Normalized EBITDA for third quarter 2014 was $104.9 million, compared to $103.5 million for same quarter 2013. Cashflow remained flat as lower contribution from the Alberta power assets was offset by the growth in earnings from the Gas and Utilities segments as well as a small contribution from Forrest Kerr.

Normalized operating income for third quarter 2014 was $59.3 million, compared to $63.5 million for same quarter 2013. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense, preferred share dividends and income taxes.

Operating and administrative expense for third quarter 2014 was $112.5 million, compared to $105.1 million for same quarter 2013. The increase was primarily due to growth in assets and increased activity to support growth initiatives. Amortization expense for third quarter 2014 was $43.6 million, compared to $39.1 million for same quarter 2013 mainly due to the asset growth of the Corporation.

Interest expense for third quarter 2014 was $28.6 million, compared to $25.2 million for same quarter 2013. Interest expense increased due to a higher average debt balance of $3,180.0 million in third quarter 2014 (third quarter 2013 - $3,005.9 million) and lower capitalized interest of $6.6 million in third quarter 2014 (third quarter 2013 - $8.4 million) as a result of Forrest Kerr coming into service in August 2014. The higher average debt balance was the result of the Corporation's growth in the past year. The increase in interest expense was partially offset by a 4 basis points reduction in the average borrowing rate to 4.4 percent in third quarter 2014.

AltaGas recorded income tax expense of $1.8 million for third quarter 2014, compared to $7.5 million for same quarter 2013. Income tax expense decreased primarily due to lower taxable earnings in third quarter 2014 compared to same quarter 2013 as a result of the gain on the sale of PTP recorded in third quarter 2013.

Nine Months Ended September 30

Normalized net income for nine months ended September 30, 2014 was $117.0 million ($0.94 per share) compared to $116.0 million ($1.02 per share) reported for same period 2013. Normalized net income remained flat in comparison to same period 2013 as results from the Power and Corporate segments were offset by favorable contributions from the Gas and Utilities segments. Results were primarily due to higher contributions from Gas assets due to increased volumes, the earnings contribution from Petrogas, continued rate base and customer growth at the utilities, colder weather, favorable foreign exchange rates on U.S. business results, the addition of Blythe, and the earnings contribution from Forrest Kerr. Normalized net income was mainly offset by lower contribution from Alberta power assets, higher compensation costs, higher preferred share dividends, lower contribution from Energy Services, lower transportation volumes, lower renewable earnings contribution, higher operating expenses, and higher interest costs. Normalized net income on a per share basis was impacted by higher shares outstanding compared to the same period 2013.

Net income applicable to common shares for nine months ended September 30, 2014 was $85.4 million ($0.69 per share) compared to $128.2 million ($1.12 per share) for same period 2013. Net income applicable to common shares for nine months ended September 30, 2014 was normalized for provisions taken for certain assets, impact from the sale of non-core assets, unrealized gain or loss on risk management contracts, unrealized gain or loss on long-term investments, transaction costs related to acquisitions, costs associated with the early redemption of MTNs and development costs incurred for the energy export projects. Net income applicable to common shares for nine months ended September 30, 2013 was normalized for similar one-time items as in year-to-date 2014, excluding the costs associated with the early redemption of MTNs in 2014, as well as the impact of statutory tax rate changes in 2013.

Normalized funds from operations for nine months ended September 30, 2014 increased by 13 percent to $315.6 million ($2.54 per share), compared to $279.3 million ($2.45 per share) for same period 2013. Normalized EBITDA for nine months ended September 30, 2014 was $391.6 million, a 10 percent increase, compared to $355.6 million for same period 2013. The increase in cashflow was a result of the significant earnings growth in the Gas and Utilities segments, as well as the addition of Forrest Kerr, which more than offset the lower contribution from Alberta power assets.

Normalized operating income for nine months ended September 30, 2014 was 8 percent higher at $260.9 million, compared to $240.7 million for the same period 2013. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense, preferred share dividends and income taxes.

Operating and administrative expense for nine months ended September 30, 2014 was $336.3 million, compared to $312.9 million for same period 2013. The increase was primarily due to asset growth of the Corporation as well as increased activity to support growth initiatives. Amortization expense for nine months ended September 30, 2014 was $126.6 million, compared to $112.1 million for same period 2013, due to asset growth of the Corporation.

Interest expense for nine months ended September 30, 2014 was $76.9 million, compared to $75.0 million for same period 2013. Interest expense increased due to a higher average debt balance of $3,224.3 million in nine months ended September 30, 2014, compared to $2,834.2 million in same period 2013. The higher debt was a result of the growth of the Corporation. The increase in interest expense was partially offset by higher capitalized interest of $27.1 million (nine months ended September 30, 2013 - $21.6 million) and by a lower average borrowing rate of 4.3 percent in nine months ended September 30, 2014 (nine months ended September 30, 2013 - 4.6 percent).

AltaGas recorded income tax expense of $24.4 million for nine months ended September 30, 2014, compared to $25.6 million for same period 2013. Income tax expense decreased primarily due to lower year-to-date taxable earnings, a gain on the disposition of PTP in third quarter 2013, and an income tax recovery of $12.0 million relating to provisions on long-lived assets. The decrease in income tax expense was partially offset by a gain on asset dispositions recorded in the first quarter 2014, recoveries booked in the second quarter 2013 relating to an adjustment to the deferred tax liability, and an income tax recovery resulting from the enactment of a Canadian tax amendment related to tax on dividends paid on preferred shares also recorded in 2013.

CONSOLIDATED OUTLOOK

In 2014, AltaGas is expected to deliver another strong year of cash flow growth, with the continued execution of the Corporation's growth strategy through the addition of strategic, long-life assets that are underpinned by long-term contracts. The diversification and growth of AltaGas' asset base will enable the Corporation to partially offset the impact of lower contributions from the Power segment in 2014 due to a weak power pricing environment and lower generation in Alberta.

AltaGas' earnings growth is underpinned by higher utilization of key gas processing assets, new assets added in the last year, Forrest Kerr, favorable weather year-to-date, and higher earnings from U.S. assets as a result of favorable exchange rates. These earnings are partially offset by the impact of asset sales completed in late 2013 and early 2014, lower contribution from Alberta power assets, higher compensation costs, higher preferred share dividends, lower performance from Energy Services, and higher taxes and interest expense.

Activity in AltaGas' Gas business will continue to be driven by continued strong natural gas demand in North America due to historically low storage rates, increased gas consumption for power generation and increasing industrial loads such as oil sands projects. In addition, it is expected that producers will continue to look to liquids-rich areas for their natural gas development, which increases opportunities for AltaGas to add and expand processing and export facilities.

In 2014, the Gas segment will benefit from the investment in Petrogas, including the contribution from the Ferndale terminal acquired by Petrogas in May 2014. In addition, it will also benefit from the increases in volumes processed at plants in liquids-rich areas, including the Gordondale facility, where the original licensed capacity of 120 Mmcf/d was increased to 150 Mmcf/d in the second quarter, and the Co-stream facility at Harmattan. AltaGas has expanded its natural gas transmission system to deliver natural gas to two heavy oil projects near Cold Lake, Alberta. The expansions are underpinned by long-term take-or-pay transportation agreements and are estimated to cost approximately $30 million. The first expansion project was completed ahead of schedule and below budget in fourth quarter 2013. Construction on the second expansion project commenced in June and is expected to be completed in late 2014, having a full year impact in 2015.

Management estimates an average of approximately 7,800 Bbls/d will be exposed to frac spread in 2014. For fourth quarter 2014, approximately 80 percent of the estimated volumes exposed to frac spread have been hedged at an average price of approximately $26/Bbl after deducting extraction premiums. For 2015, AltaGas has hedged approximately 40 percent of the estimated 7,800 Bbls/d exposed to frac spread at an average price of approximately $27/Bbl after deducting extraction premiums.

In the Power segment, earnings are expected to be driven by the full year contribution from Blythe and the start of commercial operations of Forrest Kerr, partially offset by lower contribution from Alberta power assets. Operating results could continue to be impacted in the fourth quarter if power prices remain weak and generation at the Sundance facility is lower than actual availability.

AltaGas has hedged approximately 55 percent of volumes exposed to Alberta power prices for fourth quarter 2014 at an average price of approximately $61/MWh. For 2015, AltaGas has hedged approximately 20 percent of volumes exposed to Alberta power prices at an average price of approximately $63/MWh.

The Utilities segment benefited from the normal seasonally strong first quarter, and AltaGas expects to benefit from the seasonally strong fourth quarter due to the winter heating season. The Utilities are expected to report increased earnings in 2014 driven by colder than normal weather year-to-date and continued rate base and customer growth. In addition, continued favorable exchange rates are expected to result in higher Canadian dollar earnings from the U.S. utilities in 2014.

AltaGas is well-positioned heading into 2015 and expects to benefit from the investment in Petrogas, a full year of Forrest Kerr and several other growth projects coming into service, such as Volcano Creek and McLymont Creek (McLymont).

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $500 million to $550 million for 2014. 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 plan (DRIP), and available bank lines. As at September 30, 2014, the Corporation had approximately $1.7 billion available on its credit facilities as well as cash on hand of approximately $460 million primarily from the equity issuance and MTN offering completed in third quarter 2014.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwestern British Columbia: 195 MW Forrest Kerr, 16 MW Volcano Creek and 66 MW McLymont Creek. The 277 MW Northwest Projects are contracted with 60-year Electricity Purchase Agreements (EPA) with BC Hydro fully indexed to the Consumer Price Index (CPI), as well as Impact Benefit Agreements with the Tahltan First Nation.

Forrest Kerr

The facility captures the energy produced by the natural flow and elevation drop of the Iskut River to produce and deliver clean, renewable power to the transmission grid. Construction of the Forrest Kerr facility, which commenced in 2010, was completed on time and on budget. AltaGas safely completed final commissioning of the powerhouse systems and high voltage switchyard and began generating power in July 2014. Forrest Kerr was brought into service on August 12, 2014; however, significant transmission line constraints on the NTL combined with a flooding event on the Iskut River led to delays in contractual Commercial Operations Date (COD) for Forrest Kerr. The facility met the technical parameters for contractual COD and delivered the certificate of COD to BC Hydro on October 21, 2014.

Volcano Creek

The 16 MW Volcano Creek project continues to pace two years ahead of schedule. Major construction is complete and the final commissioning is well underway. The final project COD is expected to be achieved in the fourth quarter of 2014.

McLymont Creek

At the 66 MW McLymont Creek project, construction of the powerhouse is advancing ahead of schedule, installation of the turbines is underway and excavation of the 2,800 meter power tunnel is approximately 90 percent complete. Construction of the intake access road is nearly complete and intake construction is expected to start in November. The project is expected to be in service in mid-2015.

Townsend Gas Processing Facility

On August 19, 2014 AltaGas and Painted Pony signed an agreement to enter 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, of which Painted Pony will reserve the right to a minimum of 150 Mmcf/d of 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 approximately $325 to $350 million.

Alton Natural Gas Storage Project

AltaGas has commenced construction on the Alton Natural Gas Storage project, with up to 10 Bcf of natural gas storage, located near Truro, Nova Scotia. Drilling of the wells and construction at the cavern and river sites are nearing completion. The first phase of the project is 4.5 Bcf of storage and is expected to be in service in 2017 at a construction cost of approximately $100 million. AltaGas completed a 20-year firm storage agreement with Heritage Gas Limited (Heritage Gas) for approximately 4 Bcf for the first phase, which is subject to regulatory approval by the Nova Scotia Utility and Review Board.

AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP)

On January 29, 2013, AltaGas signed an agreement with Idemitsu Kosan Co., Ltd. (Idemitsu) to form AIJVLP. AltaGas and Idemitsu each own, through subsidiaries, a 50 percent interest in AIJVLP. AIJVLP is pursuing opportunities to develop liquefaction infrastructure to meet the growing demand for natural gas in Asia. AIJVLP is also pursuing opportunities to develop a Liquefied Petroleum Gas (LPG) export business, including logistics, plant refrigeration and storage facilities. On March 1, 2014, AIJVLP completed the acquisition of two-thirds of Petrogas. Petrogas is a privately-held leading North American integrated midstream company. Petrogas' extensive logistics network provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities.

<u>LPG Export Business</u>

On May 1, 2014 Petrogas acquired the Ferndale export terminal located in the State of Washington. The facility shipped two loads, approximately 500,000 Bbls each, of Petrogas product in third quarter 2014 and is expected to increase the number of LPG shipments resulting in a ramp up over the next several years to 30,000 Bbls/d to the Petrogas account.

Through AIJVLP, AltaGas is also developing a greenfield LPG terminal on the west coast of Canada and is currently conducting site evaluation studies, which are expected to be completed in 2014. Terminal sites and refrigeration technology are being evaluated. AIJVLP is currently in discussions with key stakeholders to determine project timing, and with market participants to develop sales and logistics agreements.

<u>LNG Export Business</u>

In addition to LPG, AIJVLP is working with various parties to support the Companies' Creditors Arrangement Act (CCAA) Plan of Arrangement proceedings for the Douglas Channel LNG project. On October 29, 2014, the Supreme Court of British Columbia (the “Court”) approved the Plan of Arrangement for filing and distribution to creditors. Creditors are to review the Plan of Arrangement and vote on it. With a positive vote, the Plan of Arrangement will proceed to be sanctioned by the Court and become effective thereafter, upon satisfying other conditions prescribed in the Plan of Arrangement including finalization of transaction documents and approval of the PNG agreement from the British Columbia Utilities Commission (BCUC).

Separately, AIJVLP continues to make progress on the development of a second LNG export facility. On April 16, 2014, Triton LNG, a wholly-owned subsidiary of AIJVLP, received NEB approval to export up to 2.3 million tonnes per year of LNG. The LNG export projects are subject to consultations with First Nations, and the completion of the feasibility study, siting, permitting, regulatory approvals and facility construction.

Pacific Northern Gas Ltd. Pipeline Looping Project (PLP)

PNG continues to proceed with the development of the potential expansion of approximately 600 Mmcf/d on its natural gas transmission line. PNG has signed Transportation Reservation Agreements (TRAs) with two parties to support the PNG expansion project. Douglas Channel Gas Services Ltd., one of the parties, is currently in a CCAA proceeding, of which the outcome is not known at this time. The TRAs provide for cost recovery of development costs related to the PLP and are backstopped by letters of credit provided by the counterparties. On July 24, 2013, the British Columbia Environmental Assessment Office (BCEAO) issued an order accepting PNG’s PLP into the environmental assessment process following PNG’s filing of its project description.

On March 31, 2014, the BCEAO issued the approved Application Information Requirements (AIR), which specifies the required information in an application for environmental assessment certificate. Under the approved environmental assessment process, PNG has up to three years to provide the required information. PNG is continuing its consultation activities while undertaking the field studies necessary to address the AIR.

Sonoran Energy Project (Blythe II)

In second quarter 2014, AltaGas paid US$8.5 million to acquire the shovel ready Blythe II project, next to the existing AltaGas Blythe facility located near the California-Arizona border. AltaGas anticipates responding to expected upcoming request for proposals in the coming months, with the potential to double the size of the existing Blythe facility. AltaGas also acquired 76 acres north of the current Blythe facility that provides further opportunities to expand generating capacity at Blythe over the longer term.

Harmattan Cogeneration III

AltaGas is expanding its cogeneration fleet at Harmattan to 45 MW. In first quarter 2014, AltaGas began engineering and procured the combustion turbine for the new 15 MW Cogeneration III to meet the increased power demand at Harmattan and increase sales to the Alberta power market. Construction is well underway. Piling and major foundations are complete, the combustion turbine has been delivered to site and the upgrade and tie-in work to the existing Harmattan hot oil system are complete. Cogeneration III is on schedule and budget and is expected to be in service in first half 2015 with a total project cost estimated at $40 million.

Cold Lake Pipeline Expansion

In 2013 AltaGas announced the Cold Lake expansion projects that will supply gas to steam assisted gravity drainage heavy oil projects near Cold Lake, Alberta. These projects are underpinned by long-term take-or-pay agreements and are expected to double the utilization of the system. The system has the potential for future expansion opportunities. With the first project completed ahead of schedule in fourth quarter 2013, construction on the second project is well underway and is expected to be completed in late 2014.

Regional LNG

AltaGas is developing a small scale LNG production facility in Dawson Creek, British Columbia. Capital cost of the Regional LNG project is estimated to be approximately $35 million and first sales are expected in 2015. This LNG production facility is expected to displace diesel fuel in both the commercial and residential markets in the area. As market demand for LNG to displace diesel fuel further develops, expansion of the business may occur in British Columbia and other regions.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures and other investing activities. The specific rationale for and incremental information associated with each non-GAAP measure is discussed below.

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

Net Revenue		Three months ended September 30		Nine months ended September 30	
($ millions)		**2014**	2013	**2014**	2013
Net revenue [1]	**$**	**217.4**	$ 246.6	**$ 733.9**	$ 695.6
Add (deduct):					
Other income (expenses)		**(1.2)**	(38.2)	**(12.6)**	(38.5)
Income from equity investments		**(13.4)**	(30.1)	**(38.0)**	(96.3)
Cost of sales		**241.4**	211.4	**1,055.9**	901.0
Revenue (GAAP financial measure)	**$**	**444.2**	$ 389.7	**$ 1,739.2**	$ 1,461.8

[1] *Amounts may not add due to rounding.*

Management believes that net revenue, which is revenue plus other income (expenses) 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 September 30		Nine months ended September 30	
($ millions)		**2014**	2013	**2014**	2013
Normalized operating income	**$**	**59.3**	$ 63.5	**$ 260.9**	$ 240.7
Add (deduct):					
Transaction costs related to acquisitions		**(0.1)**	(0.2)	**(0.1)**	(1.5)
Unrealized gain (loss) on long-term investments		**(0.4)**	(0.2)	**0.1**	(1.1)
Provision for long-lived assets		**-**	(18.9)	**(49.2)**	(19.5)
Costs associated with early redemption of MTNs		**-**	-	**(2.3)**	-
Gain (loss) on asset dispositions		**-**	37.5	**11.1**	37.5
Joint venture development costs		**(0.6)**	(0.8)	**(0.9)**	(0.8)
Operating income		**58.2**	80.9	**219.6**	255.3
Add (deduct):					
Unrealized gain (loss) on risk management contracts		**1.1**	1.6	**(1.8)**	(7.1)
Interest expense		**(28.6)**	(25.2)	**(76.9)**	(75.0)
Foreign exchange gain (loss)		**(0.5)**	0.2	**(0.3)**	0.2
Income tax expense		**(1.8)**	(7.5)	**(24.4)**	(25.6)
Net income applicable to non-controlling interests		**(2.0)**	(1.9)	**(6.2)**	(5.3)
Preferred share dividends		**(9.8)**	(4.8)	**(24.6)**	(14.3)
Net income applicable to common shares (GAAP financial measure)	**$**	**16.6**	$ 43.3	**$ 85.4**	$ 128.2

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 using net income applicable to common shares adjusted for pre-tax unrealized gain (loss) on risk management contracts, interest expense, foreign exchange gain or loss, income tax 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, unrealized gain (loss) on long-term investments, provision taken for 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 development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized EBITDA		Three months ended September 30		Nine months ended September 30
($ millions)	**2014**	2013	**2014**	2013
Normalized EBITDA	**$ 104.9**	$ 103.5	**$ 391.6**	$ 355.6
Add (deduct):				
Transaction costs related to acquisitions	**(0.1)**	(0.2)	**(0.1)**	(1.5)
Unrealized gain (loss) on long-term investments	**(0.4)**	(0.2)	**0.1**	(1.1)
Gain (loss) on asset dispositions	**-**	37.5	**11.1**	37.5
Joint venture development costs	**(0.6)**	(0.8)	**(0.9)**	(0.8)
Costs associated with early redemption of MTNs	**-**	-	**(2.3)**	-
EBITDA	**103.8**	139.8	**399.5**	389.7
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**1.1**	1.6	**(1.8)**	(7.1)
Depreciation, depletion and amortization	**(43.6)**	(39.1)	**(126.6)**	(112.1)
Provision for long-lived assets	**-**	(18.9)	**(49.2)**	(19.5)
Accretion expense	**(2.0)**	(0.9)	**(4.1)**	(2.8)
Interest expense	**(28.6)**	(25.2)	**(76.9)**	(75.0)
Foreign exchange gain (loss)	**(0.5)**	0.2	**(0.3)**	0.2
Income tax expense	**(1.8)**	(7.5)	**(24.4)**	(25.6)
Net income applicable to non-controlling interests	**(2.0)**	(1.9)	**(6.2)**	(5.3)
Preferred share dividends	**(9.8)**	(4.8)	**(24.6)**	(14.3)
Net income applicable to common shares (GAAP financial measure)	**$ 16.6**	$ 43.3	**$ 85.4**	$ 128.2

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 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 for long-lived assets, accretion of long-term obligations, interest expense, foreign exchange gain or loss, income tax 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 transaction costs related to acquisitions, unrealized gain (loss) on long-term investments, gain (loss) on asset dispositions, and costs associated with early redemption of MTNs. Normalized EBITDA also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized Net Income	Three months ended September 30		Nine months ended September 30	
($ millions)	**2014**	2013	**2014**	2013
Normalized net income	**$ 16.6**	$ 24.7	**$ 117.0**	$ 116.0
Add (deduct) after-tax:				
Unrealized gain (loss) on risk management contracts	**0.8**	1.2	**(1.3)**	(5.4)
Unrealized gain (loss) on long-term investments	**(0.3)**	(0.2)	**0.1**	(1.0)
Transaction costs related to acquisitions	**(0.1)**	(0.1)	**(0.1)**	(1.0)
Gain (loss) on asset dispositions	**-**	32.8	**8.9**	32.8
Provision for long-lived assets	**-**	(14.1)	**(36.8)**	(14.6)
Joint venture development costs	**(0.4)**	(0.6)	**(0.7)**	(0.6)
Costs associated with early redemption of MTNs	**-**	-	**(1.7)**	-
Statutory tax rate change	**-**	(0.4)	**-**	2.0
Net income applicable to common shares (GAAP financial measure)	**$ 16.6**	$ 43.3	**$ 85.4**	$ 128.2

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 transaction costs related to acquisitions, gain (loss) on asset dispositions, provision taken for long-lived assets, costs associated with early redemption of MTNs, and statutory tax rate changes. Normalized net income also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs by AltaGas.

Normalized Funds from Operations	Three months ended September 30		Nine months ended September 30	
($ millions)	**2014**	2013	**2014**	2013
Normalized funds from operations	**$ 79.9**	$ 80.2	**$ 315.6**	$ 279.3
Add (deduct):				
Transaction costs related to acquisitions	**(0.1)**	(0.2)	**(0.1)**	(1.5)
Funds from operations	**79.8**	80.0	**315.5**	277.8
Add (deduct):				
Net change in operating assets and liabilities	**(6.4)**	74.9	**42.0**	113.6
Asset retirement obligations settled	**(0.3)**	(0.2)	**(1.0)**	(0.8)
Cash from operations (GAAP financial measure)	**$ 73.1**	$ 154.7	**$ 356.5**	$ 390.6

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 September 30		Nine months ended September 30	
($ millions)	**2014**	2013	**2014**	2013
Gas	**$ 39.0**	$ 26.3	**$ 126.5**	$ 74.4
Power	**19.4**	37.6	**48.5**	92.9
Utilities	**7.8**	7.5	**108.9**	94.3
Sub-total: Operating Segments	**66.2**	71.4	**283.9**	261.6
Corporate	**(6.9)**	(7.9)	**(23.0)**	(20.9)
	$ 59.3	$ 63.5	**$ 260.9**	$ 240.7

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

GAS

OPERATING STATISTICS	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Total inlet gas processed (Mmcf/d)(1)	**1,447**	1,244	**1,499**	1,330
Extraction ethane volumes (Bbls/d)(1) (2)	**35,395**	29,661	**34,051**	32,216
Extraction NGL volumes (Bbls/d)(1) (2)	**37,574**	33,932	**37,569**	30,078
Total extraction volumes (Bbls/d)(1) (2)	**72,969**	63,593	**71,620**	62,294
Frac spread - realized ($/Bbl)(1) (3)	**18.43**	24.63	**23.74**	24.93
Frac spread - average spot price ($/Bbl)(1) (4)	**20.82**	28.64	**28.18**	24.95

(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, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.*

Total inlet gas processed for the three and nine months ended September 30, 2014 increased by 203 and 169 Mmcf/d, respectively compared to the same periods in 2013. The increase was primarily driven by higher volumes processed at Harmattan due to higher Harmattan Co-stream volumes, higher Gordondale and Blair Creek volumes from increased producer drilling, and higher Younger volumes primarily from increased inlet volumes on the Septimus line. The increase in total inlet gas processed was partially offset by the sale of Ante Creek, and the Acme facility shut-in.

Average ethane volumes produced for the three and nine months ended September 30, 2014 increased by 5,734 and 1,835 Bbls/d, respectively, while NGL volumes produced increased by 3,642 and 7,491 Bbls/d compared to the same periods in 2013. Higher ethane volumes were due to increased volumes at Harmattan Co-stream and Empress, partially offset by downstream operational constraints at Edmonton Ethane Extraction Plant (EEEP) and Younger. Higher NGL volumes were due to increased inlet volumes at Harmattan, Younger and Gordondale.

Three Months Ended September 30

The Gas segment reported normalized operating income of $39.0 million in third quarter 2014, compared to $26.3 million in same quarter 2013. The increase was mainly a result of higher volumes processed at the Harmattan, Gordondale, and Blair Creek facilities and the contribution to earnings from Petrogas, slightly offset by lower realized frac prices.

The Gas segment reported operating income of $38.3 million in third quarter 2014, compared to $8.9 million in same quarter 2013. Results were due to the items described above as well as the $15.9 million provision taken for certain non-core assets in third quarter 2013.

During third quarter 2014, AltaGas hedged 63 percent of frac exposed production at an average price of approximately $24/Bbl. During third quarter 2013, AltaGas hedged 73 percent of frac exposed production at an average price of approximately $28/Bbl. The average indicative spot NGL frac spread for third quarter 2014 was approximately $21/Bbl, compared to approximately $29/Bbl in same quarter 2013.

Nine Months Ended September 30

The Gas segment reported a 70 percent increase in normalized operating income to $126.5 million for nine months ended September 30, 2014 compared to $74.4 million for same period 2013. The increase was primarily a result of the contribution from increased volumes processed at the Harmattan, Gordondale and Blair Creek facilities as well as higher frac exposed volumes, and the earnings contribution from Petrogas. The increase was partially offset by higher costs to fulfill firm delivery commitments from operational curtailments resulting from the combination of extremely cold weather in eastern North America and low storage levels in the first quarter 2014, higher operating expenses related to turnarounds at various gas facilities, and lower earnings contribution from transportation volumes.

The Gas segment reported operating income of $98.0 million for nine months ended September 30, 2014, compared to $57.0 million for same period 2013. Results for nine months ended September 30, 2014 include the impact of the pre-tax provision of $38.3 million taken for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and partially offset by the pre-tax gain from the sale of the Ante Creek facility of $12.0 million, both recorded in first quarter 2014. Results for nine months ended September 30, 2013 included the $15.9 million provision taken for certain non-core assets.

During nine months ended September 30, 2014, AltaGas hedged 67 percent of frac exposed production at an average price of approximately $25/Bbl. During nine months ended September 30, 2013 AltaGas hedged 52 percent of frac exposed production at an average price of approximately $27/Bbl. The average indicative spot NGL frac spread for nine months ended September 30, 2014 was approximately $28/Bbl compared to approximately $25/Bbl in same period 2013.

POWER

OPERATING STATISTICS	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Volume of power sold (GWh) [(1)]	**1,464**	1,256	**3,712**	3,158
Average price realized on the sale of power ($/MWh) [(2)]	**74.51**	79.42	**66.63**	79.96
Alberta Power Pool average spot price ($/MWh)	**64.34**	83.61	**55.80**	90.84

(1) *Power sold from Sundance B is disclosed as volumes based on target availability and not volumes delivered.*

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

During third quarter 2014, volume of power sold increased by 208 GWh compared to same quarter 2013. Volumes sold during third quarter 2014 comprised of 1,309 GWh conventional power generation and 155 GWh of renewable power generation, compared to 1,148 GWh conventional power generation and 108 GWh renewable power generation in same quarter 2013. Third quarter 2014 delivered volumes from Sundance units were lower than actual availability.

During nine months ended September 30, 2014, volume of power sold increased by 554 GWh compared to same period of 2013. Volumes sold during nine months ended September 30, 2014 comprised of 3,321 GWh of conventional power generation and 391 GWh renewable power generation, compared to 2,798 GWh conventional power generation and 360 GWh renewable power generation in same period 2013. The increase in power generated was primarily due to the Blythe acquisition in May 2013 and the contribution from Forrest Kerr coming into service in August 2014. During nine months ended September 30, 2014, Blythe and Forrest Kerr generated 1,144 and 65 GWh of power, respectively. Year-to-date 2014 delivered volumes were lower than actual availability at Sundance B.

Three Months Ended September 30

The Power segment reported normalized operating income of $19.4 million for third quarter 2014, compared to $37.6 million for same quarter 2013. Normalized operating income decreased primarily as a result of lower generation from Alberta assets accompanied by a 23 percent decline in Alberta Power Pool spot prices. The decrease was partially offset by decreased costs as a result of lower generation from Alberta assets and the earnings contribution from Forrest Kerr.

Operating income in the Power segment was $19.3 million in third quarter 2014, compared to $37.6 million in same quarter 2013. Operating income includes $0.1 million of transaction costs related to potential acquisitions.

In third quarter 2014, AltaGas was 55 percent hedged in Alberta at an average price of $67/MWh. In third quarter 2013, AltaGas was 62 percent hedged at an average price of $70/MWh.

Nine Months Ended September 30

The Power segment reported normalized operating income of $48.5 million for nine months ended September 30, 2014, compared to $92.9 million for same period 2013. Normalized operating income decreased as a result of a 39 percent decrease in Alberta Power Pool spot prices, lower generation from Alberta assets, increased administrative expenses to support growth, lower volumes at Bear Mountain, and lower biomass earnings. The decrease was partially offset by the addition of Blythe, which was acquired on May 16, 2013, the earnings contribution from Forrest Kerr, which went into in-service on August 12, 2014, and increased commercial and industrial customer growth in Alberta.

Operating income in the Power segment was $37.3 million for nine months ended September 30, 2014 compared to $91.1 million for same period 2013. Operating income for the nine months ended September 30, 2014 includes the impact of a $10.9 million pre-tax provision taken for a number of small hydro power development projects in British Columbia, and a $0.2 million pre-tax loss on disposal of a non-core biomass development asset.

For the nine months ended September 30, 2014, AltaGas was 54 percent hedged in Alberta at an average price of $64/MWh. For the nine months ended September 30, 2013, AltaGas was 63 percent hedged at an average price of $66/MWh.

UTILITIES

OPERATING STATISTICS	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Canadian utilities				
Natural gas deliveries - end-use (PJ)[(1)]	**3.1**	2.7	**22.1**	19.7
Natural gas deliveries - transportation (PJ)[(1)]	**1.0**	1.2	**4.1**	4.2
US utilities				
Natural gas deliveries - end-use (Bcf)[(1)]	**6.1**	5.8	**49.2**	46.2
Natural gas deliveries - transportation (Bcf)[(1)]	**8.5**	8.0	**29.3**	30.6
Service sites [(2)]	**554,837**	548,013	**554,837**	548,013
Degree day variance from normal - AUI (%) [(3)]	**(6.2)**	(39.1)	**5.8**	(5.9)
Degree day variance from normal - Heritage Gas (%) [(3)]	**(1.5)**	(8.0)	**3.6**	(2.4)
Degree day variance from normal - SEMCO Gas (%) [(4)]	**44.7**	26.4	**22.0**	7.8
Degree day variance from normal - ENSTAR (%) [(4)]	**(8.3)**	(6.4)	**(8.1)**	(0.8)

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

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

(3) *A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.*

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

Three Months Ended September 30

The Utilities segment reported normalized operating income of $7.8 million for third quarter 2014, compared to $7.5 million for same quarter 2013. Results were higher for third quarter 2014 due to continued customer and rate base growth combined with higher volumes delivered due to colder weather experienced. The increase in normalized operating income was offset by higher expenses and depreciation as a result of growth.

The Utilities segment reported operating income of $7.8 million in third quarter 2014, compared to $42.0 million in same quarter 2013. Results were due to the items described above as well as the gain on the sale of PTP and the $3.0 million provision taken for assets in Inuvik in third quarter 2013.

Nine Months Ended September 30

The Utilities segment reported a 15 percent increase in normalized operating income to $108.9 million for nine months ended September 30, 2014, compared to $94.3 million for same period 2013. The increase was mainly due to customer and rate base growth, colder weather, and favorable foreign exchange on the U.S. business results. The increase in operating income was partially offset by higher expenses and depreciation as a result of growth.

The Utilities segment reported operating income of $108.9 million for nine months ended September 30, 2014, compared to $128.8 million for same period 2013. Results were due to the items described above as well as the gain on the sale of PTP and the $3.0 million provision taken for assets in Inuvik in third quarter 2013.

CORPORATE

Three Months Ended September 30

In the Corporate segment, normalized operating loss for third quarter 2014 was $6.9 million, compared to $7.9 million in same quarter 2013. The lower normalized operating loss was due to lower administrative expenses related to energy export initiatives. Operating loss in the Corporate segment was $7.1 million for third quarter 2014, which includes costs associated with unrealized gains on risk management contracts, compared to $7.6 million for same quarter 2013.

Nine Months Ended September 30

Normalized operating loss for nine months ended September 30, 2014 was $23.0 million, compared to $20.9 million in same period 2013. The higher normalized operating loss was primarily due to increased administrative expenses, partially offset by lower amortization and higher interest income. The operating loss in the Corporate segment for nine months ended September 30, 2014 was $24.7 million compared to $21.6 million for same period 2013. The increase in loss was due to increased administrative expenses to support business growth and for energy export initiatives, partially offset by lower amortization and higher interest income.

INVESTED CAPITAL

During third quarter 2014, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $199.2 million, compared to $163.4 million in same quarter 2013. The net invested capital was $199.2 million for three months ended September 30, 2014, compared to $161.4 million for same quarter 2013.

Invested Capital - Investment Type — **Three months ended September 30, 2014**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 25.6**	**$ 59.9**	**$ 49.5**	**$ 0.7**	**$ 135.7**
Intangible assets	**0.1**	**5.3**	**-**	**5.3**	**10.7**
Long-term investments	**2.8**	**-**	**-**	**50.0**	**52.8**
Invested capital	**28.5**	**65.2**	**49.5**	**56.0**	**199.2**
Disposals:					
Property, plant and equipment	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**$ 28.5**	**$ 65.2**	**$ 49.5**	**$ 56.0**	**$ 199.2**

Invested Capital - Investment Type — Three months ended September 30, 2013

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 8.7	$ 102.0	$ 43.1	$ 0.5	$ 154.3
Intangible assets	0.2	-	1.5	5.5	7.2
Long-term investments	0.1	-	-	1.8	1.9
	9.0	102.0	44.6	7.8	163.4
Disposals:					
Property, plant and equipment	(2.0)	-	-	-	(2.0)
Net Invested capital	$ 7.0	$ 102.0	$ 44.6	$ 7.8	$ 161.4

In the Gas segment, invested capital included $17.1 million for Alton, $2.8 million invested in AIJVLP, $2.3 million for the Cold Lake System expansion, $0.7 million for Regional LNG, $0.4 million for Townsend and $2.4 million for various small Gas related projects. The invested capital for Gas included $2.8 million of maintenance capital.

In the Power segment, invested capital included $32.1 million for Forrest Kerr, $17.1 million for McLymont, $5.9 million for Volcano, $3.3 million for Cogeneration III, $1.9 million for Parkland peaking plant, and $0.2 million related to Blythe II. During the quarter, the Power segment paid $5.3 million to BC Hydro in support of the construction and operation of the NTL and decreased the accrued costs for the Blythe turnaround by $0.6 million.

The Utilities segment invested $21.2 million at the Canadian utilities and $23.2 million at the U.S. utilities. During third quarter 2014, the Utilities segment expenditure on PNG PLP project was $5.1 million.

The Corporate segment reported an increase in expenditure of $6.0 million, primarily due to information technology projects. During third quarter 2014, AltaGas also acquired $50.0 million equity interest in Painted Pony.

During nine months ended September 30, 2014, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $460.6 million, compared to $937.6 million for same period 2013. The net invested capital was $433.6 million for nine months ended September 30, 2014, compared to $935.0 million for same period 2013.

Invested Capital - Investment Type — **Nine months ended September 30, 2014**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 46.9**	**$ 227.2**	**$ 108.1**	**$ 3.4**	**$ 385.6**
Intangible assets	**0.3**	**5.3**	**0.7**	**12.6**	**18.9**
Long-term investments	**6.1**	**-**	**-**	**50.0**	**56.1**
Invested capital	**53.3**	**232.5**	**108.8**	**66.0**	**460.6**
Disposals:					
Property, plant and equipment	**(26.8)**	**(0.2)**	**-**	**-**	**(27.0)**
Net Invested capital	**$ 26.5**	**$ 232.3**	**$ 108.8**	**$ 66.0**	**$ 433.6**

Invested Capital - Investment Type — Nine months ended September 30, 2013

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 22.0	$ 799.0	$ 96.8	$ 1.7	$ 919.5
Intangible assets	3.3	0.1	3.5	8.9	15.8
Long-term investments	0.4	-	-	1.9	2.3
	25.7	799.1	100.3	12.5	937.6
Disposals:					
Property, plant and equipment	(2.6)	-	-	-	(2.6)
Net Invested capital	$ 23.1	$ 799.1	$ 100.3	$ 12.5	$ 935.0

In the Gas segment, invested capital included $29.5 million for Alton, $6.1 million invested in AIJVLP, $3.7 million for the Cold Lake System expansion, $2.2 million for Harmattan and $5.6 million for various small Gas related projects. During nine months ended September 30, 2014, the Gas segment received $26.8 million in proceeds from sale of long-lived assets. The invested capital for Gas included $6.2 million of maintenance capital.

In the Power segment, invested capital included $126.2 million for Forrest Kerr, $46.1 million for McLymont, $13.0 million for Volcano, $11.3 million related to Blythe II, $9.3 million for Parkland peaking plant, and $8.9 million for Cogeneration III. During nine months ended September 30, 2014, the Power segment received $0.2 million in proceeds from sale of long-lived assets. The invested capital for Power also included $12.4 million related to the turnaround at Blythe, which is amortized over four to eight years to align with the timing of major turnarounds at the facility. During nine months ended September 30, 2014, the Power segment paid $5.3 million to BC Hydro in support of the construction and operation of the NTL.

The Utilities segment invested $48.1 million at the Canadian utilities, $52.9 million at the U.S. utilities and $0.5 million related to the compressed natural gas business at Heritage Gas. During nine months ended September 30, 2014, the Utilities segment expenditure on PNG PLP project was $7.3 million.

The Corporate segment reported an increase in expenditure of $16.0 million, primarily due to information technology projects. During nine months ended September 30, 2014, AltaGas acquired a $50.0 million equity interest in Painted Pony.

RISK MANAGEMENT

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During third quarter 2014, the Corporation had positions in the following types of derivatives, which are also disclosed in the unaudited 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 $8.91/MWh to $999.99/MWh in third quarter 2014 and $0.00/MWh to $1000.00/MWh in third quarter 2013. The average Alberta spot price was $64.34/MWh in third quarter 2014 (third quarter 2013 - $83.61/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 price realized for power by AltaGas was $74.51/MWh in third quarter 2014 (third quarter 2013 - $79.42/MWh). For fourth quarter 2014, AltaGas has hedged approximately 55 percent of volumes exposed to Alberta power prices at an average price of approximately $61/MWh. For 2015, approximately 20 percent of volumes exposed to Alberta power prices have been hedged at an average price of approximately $63/MWh.

NGL frac spread hedges:

The Corporation executes fixed for floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During third quarter 2014, the Corporation had NGL frac spread hedges for an average of 5,000 Bbls/d at an average price of approximately $24/Bbl. The average indicative spot NGL frac spread for third quarter 2014 was an estimated $21/Bbl (third quarter 2013 – $29/Bbl). The average NGL frac spread realized by AltaGas in third quarter 2014 was $18/Bbl (third quarter 2013 - $25/Bbl). Management estimates an average of approximately 7,800 Bbls/d will be exposed to frac spread in 2014. For fourth quarter 2014, AltaGas has hedged approximately 80 percent of volumes exposed to frac spread at an average price of approximately $26/Bbl after deducting extraction premiums. For 2015, approximately 40 percent of estimated volumes exposed to frac spread have been hedged at an average price of approximately $27/Bbl after 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 September 30, 2014, the Corporation had no interest rate swaps outstanding. At September 30, 2014, the Corporation had fixed the interest rate on 88 percent of its debt including MTNs (September 30, 2013 - 76 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 a long-term debt matures or is settled. As at September 30, 2014, management designated US$375.0 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2013 - US$570.0 million). US dollar denominated long-term debt has 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 September 30		Nine months ended September 30	
($ millions)	**2014**	2013	**2014**	2013
Cash from operations	**$ 73.1**	$ 154.7	**$ 356.5**	$ 390.6
Investing activities	**(214.9)**	(191.6)	**(432.8)**	(953.8)
Financing activities	**573.9**	2.1	**491.3**	611.6
Effect of exchange rate	**2.1**	(0.2)	**2.3**	0.3
Change in cash	**$ 434.2**	$ (35.0)	**$ 417.3**	$ 48.7

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $356.5 million in nine months ended September 30, 2014 compared to $390.6 million in same period 2013. Cash from operations decreased as result of lower earnings primarily in Power, lower distributions from equity investments as well as higher natural gas inventory levels and lower cash from collection of accounts receivable, partially offset by higher earnings in Gas.

Working Capital		
As at September 30	**2014**	2013
($ millions except current ratio)		
Current assets	**$ 947.6**	$ 541.4
Current liabilities	**609.8**	879.4
Working capital	**337.8**	(338.0)
Current ratio	**1.55**	0.62

Working capital was $337.8 million as at September 30, 2014, compared to working capital deficit of $338.0 million as at September 30, 2013. The working capital ratio was 1.55 at the end of third quarter 2014, compared to 0.62 at the end of same quarter 2013. The working capital ratio increased due to a higher cash balance as at September 30, 2014, compared to the balance as at September 30, 2013 primarily due to cash on hand as a result of debt and equity financings completed in third quarter 2014.

Investing Activities

Cash used for investing activities in nine months ended September 30, 2014 was $432.8 million compared to $953.8 million in same period 2013. Investing activities in nine months ended September 30, 2014 comprised expenditures of $388.4 million for property, plant and equipment, $19.8 million for intangible assets and $50.0 million for acquisition of an equity investment, partially offset by proceeds of $27.2 million received on disposition of assets. Investing activities in nine months ended September 30, 2013 primarily comprised of the Blythe acquisition for $536.8 million, $419.1 million for property, plant and equipment and $40.8 million for intangible assets.

Financing Activities

Cash received from financing activities in nine months ended September 30, 2014 was $491.3 million, compared to $611.6 million in same period 2013. Financing activities in nine months ended September 30, 2014 were primarily comprised of net proceeds from issuance of common shares of $491.5 million, issuance of preferred shares of $194.5 million, issuance of long-term debt of $1,046.8 million, partially offset by repayments of long-term and short-term debt, $1,022.4 million and $49.5 million respectively. Financing activities in nine months ended September 30, 2013 were primarily comprised of net proceeds from issuance of common shares of $432.2 million and issuance of $1,155.6 million of long-term debt, partially offset by $791.4 million repayment of long-term debt, and $59.4 million repayment of short-term debt. Total dividends paid in nine months ended September 30, 2014 were $176.2 million, compared to $138.7 million in same period 2013. The increase was due to higher shares outstanding and dividend increases.

CAPITAL RESOURCES

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

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments.

As at September 30, 2014, AltaGas had $2,745.1 million in MTNs outstanding, PNG debenture notes of $59.1 million, SEMCO Energy, Inc. (SEMCO) long-term debt of $428.8 million and $190.2 million drawn from bank credit facilities. As at September 30, 2014, AltaGas' current portion of long-term debt was $206.4 million.

AltaGas' earnings coverage ratio, which is defined as the consolidated net income before interest and income taxes divided by total interest expense, for the rolling twelve months ended September 30, 2014 was 2.3 times.

AltaGas' debt-to-total capitalization ratio as at September 30, 2014 was 44.3 percent (December 31, 2013 - 53.1 percent).

($ thousands)		**September 30, 2014**		December 31, 2013
Debt				
Short-term debt	**$**	**38,180**	$	84,350
Current portion of long-term debt		**206,394**		209,069
Long-term debt		**3,030,323**		2,952,673
Less: cash and cash equivalent		**(462,154)**		(44,812)
Net debt		**2,812,743**		3,201,280
Shareholders' equity		**3,507,322**		2,791,707
Non-controlling interests		**34,617**		37,763
Total capitalization	**$**	**6,354,682**	$	6,030,750
Debt-to-total capitalization ratio (%)		**44.3**		53.1

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 September 30, 2014:

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

As at September 30, 2014, the Corporation had approximately $1.7 billion of available credit facilities and $462.2 million in cash and cash equivalents.

On April 4, 2013, AltaGas closed a public offering of 11,615,000 common shares at a price of $34.90 per common share for aggregate gross proceeds of approximately $405 million.

On April 12, 2013, AltaGas issued US$175 million of senior unsecured MTNs. The notes carry a floating rate coupon of three-month LIBOR plus 0.79 percent and mature on April 13, 2015.

On May 17, 2013, the CINGSA construction credit facility for US$90 million was converted to a term loan of US$82.1 million with maturity of November 14, 2015. The loan was repaid on June 10, 2014.

On June 7, 2013, PNG repaid and cancelled its $35 million term revolver. The majority of the funds used to repay the term revolver were sourced from PNG's new five-year $70 million revolving term facility provided by AltaGas.

On June 11, 2013, AltaGas issued $300 million of senior unsecured MTNs. The notes carry a coupon rate of 3.57 percent and mature on June 12, 2023.

On August 23, 2013, a new $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 September 30, 2014, $2.3 billion remains available on the base shelf prospectus.

On December 13, 2013, AltaGas issued 8,000,000 five-year rate-reset Series E Preferred Shares, at a price of $25 per Series E Preferred Share for aggregate gross proceeds of $200 million.

On December 20, 2013, SEMCO amended its US$100 million unsecured credit facility dated August 30, 2012 by increasing the size of the facility to US$150 million and extending the maturity date to December 20, 2018.

On December 20, 2013 AltaGas entered into an agreement for a $1.4 billion unsecured credit facility which expires on December 15, 2017. This facility replaces the $200 million Utility Group revolving credit facility, the US$300 million unsecured credit facility and the $600 million AltaGas Ltd. revolving credit facility.

On January 13, 2014, AltaGas issued $200 million of senior unsecured MTNs with a coupon rate of 4.40 percent and maturity of March 15, 2024 and $100 million senior unsecured MTNs with a coupon rate of 5.16 percent and maturity of January 13, 2044.

On February 14, 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.

On March 24, 2014, AltaGas issued US$200 million of senior unsecured MTNs with a floating rate coupon of three month LIBOR plus 0.72 percent and maturity of March 24, 2016.

On June 10, 2014, CINGSA issued US$82 million of senior secured notes in a private placement transaction. The notes carry a coupon rate of 4.48 percent and mature on March 2, 2032.

On July 3, 2014, AltaGas issued 8,000,000 five-year rate-reset Series G Preferred Shares, at a price of $25 per Series G Preferred Share for aggregate gross proceeds of $200 million.

On August 15, 2014, AltaGas issued $300 million of senior unsecured MTNs with a coupon rate of 4.50 percent and maturity of August 15, 2044.

On August 28, 2014, AltaGas issued 9,027,500 Common Shares at a price of $51 per Common Share for aggregate gross proceeds of $460 million.

Credit Facilities

($ millions)		Borrowing capacity		**Drawn at September 30 2014**		Drawn at December 31 2013
Demand operating facilities	$	70.0	**$**	**3.6**	$	10.8
Extendible revolving letter of credit facility		150.0		**107.8**		67.5
PNG operating facility		25.0		**7.3**		15.3
Bilateral letter of credit facility		125.0		**30.4**		67.6
AltaGas Ltd. revolving credit facility		1,400.0		**-**		597.6
SEMCO Energy US$ unsecured credit facility (1) (2)		150.0		**41.1**		63.7
	$	1,920.0	**$**	**190.2**	$	822.5

(1) *Amount drawn at September 30, 2014 converted at September 2014 month-end rate of 1 US dollar = 1.1208 Canadian dollar (Amount drawn at December 31, 2013 converted at December 2013 month-end rate of 1 US dollar = 1.0636 Canadian dollar).*

(2) *Borrowing capacity assumed at par.*

SHARE INFORMATION

As at September 30, 2014, AltaGas had outstanding 133.1 million common shares, 8.0 million series A Preferred Shares, 8.0 million series C US$ Preferred Shares, 8.0 million series E Preferred Shares, and 8.0 million series G Preferred Shares with a combined market capitalization of approximately $7.1 billion based on a closing trading price on September 30, 2014 of $47.29 per common share, $25.20 per series A Preferred Share, $26.04 per series C US$ Preferred Share, $26.20 per series E Preferred Share and $25.75 per series G Preferred Share, respectively.

As at September 30, 2014, there were 4.9 million options outstanding and 2.6 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, capital expenditures, and debt repayment requirements of AltaGas.

On September 10, 2012, the Board of Directors approved an increase in the monthly dividend to $0.12 per common share from $0.115 per common share effective with the September dividend.

On April 24, 2013, the Board of Directors approved an increase in the monthly dividend to $0.125 per common share from $0.12 per common share effective with the May dividend.

On July 31, 2013, the Board of Directors approved an increase in the monthly dividend to $0.1275 per common share from $0.125 per common share effective with the August dividend.

On April 30, 2014, the Board of Directors approved an increase in the monthly dividend to $0.1475 per common share from $0.1275 per common share effective with the May dividend.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Years ended December 31 ($ per common share)	2014	2013
First quarter	$ 0.3825	$ 0.36
Second quarter	0.4025	0.37
Third quarter	0.4425	0.38
Fourth quarter	-	0.3825
Total	$ 1.2275	$ 1.4925

Series A Preferred Share Dividends

Years ended December 31 ($ per preferred share)	2014	2013
First quarter	$ 0.3125	$ 0.3125
Second quarter	0.3125	0.3125
Third quarter	0.3125	0.3125
Fourth quarter	-	0.3125
Total	$ 0.9375	$ 1.25

Series C Preferred Share Dividends

Years ended December 31 (US$ per preferred share)	2014	2013
First quarter	$ 0.275	0.275
Second quarter	0.275	0.275
Third quarter	0.275	0.275
Fourth quarter	-	0.275
Total	$ 0.825	$ 1.10

Series E Preferred Share Dividends

Years ended December 31 ($ per preferred share)	2014	2013
First quarter	$ 0.3699	-
Second quarter	0.3125	-
Third quarter	0.3125	-
Fourth quarter	-	-
Total	$ 0.9949	-

Series G Preferred Share Dividends

Years ended December 31 ($ per preferred share)	2014	2013
First quarter	$ -	-
Second quarter	-	-
Third quarter	0.2896	-
Fourth quarter	-	-
Total	$ 0.2896	-

SIGNIFICANT ACCOUNTING POLICIES

Reference should be made to the audited Consolidated Financial Statements as at and for the year ended December 31, 2013 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' 2013 Financial Report and the notes to the unaudited interim Consolidated Financial Statements for the three and nine months ended September 30, 2014.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. AltaGas has no obligation under derivative instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services.

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, with the assistance of AltaGas employees, 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).

During third quarter 2014, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

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

($ millions)	**Q3-14**	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12
Total revenue	**444.2**	471.2	823.8	581.2	389.7	458.6	613.5	525.8
Net revenue[2]	**217.4**	219.9	296.5	264.6	246.6	211.8	237.1	207.6
Normalized operating income[2]	**59.3**	64.5	137.0	111.9	63.5	68.0	109.2	96.4
Net income before taxes	**30.2**	44.0	66.3	75.1	57.4	39.6	76.4	51.8
Net income applicable to common shares	**16.6**	28.9	39.9	53.2	43.3	35.9	49.0	26.7
($ per share)	**Q3-14**	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12
Net income applicable to common shares								
Basic	**0.13**	0.23	0.33	0.44	0.36	0.31	0.46	0.25
Diluted	**0.13**	0.23	0.32	0.43	0.35	0.30	0.45	0.25
Dividends declared	**0.44**	0.42	0.38	0.38	0.38	0.37	0.36	0.36

(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 fourth quarter 2012, AltaGas wrote down $2.9 million related to three wind projects under development;
- In fourth quarter 2012, AltaGas received an independent arbitration panel ruling regarding a claim of force majeure on Sundance Unit 3. As a result, AltaGas recorded a $11.0 million charge in cost of sales which was previously accrued in accounts receivable;
- In second quarter 2013, AltaGas completed the acquisition of Blythe for total consideration of US$515 million; AltaGas recorded $1.6 million in pre-tax transaction costs;
- In second quarter 2013, AltaGas recorded an adjustment to its deferred tax liability and an income tax recovery resulting from the enactment of a Canadian tax amendment that increased the deduction arising from the tax on dividends paid on preferred shares;
- In third quarter 2013, AltaGas reported a $37.5 million pre-tax gain on the sale of PTP by PNG;
- In third quarter 2013, AltaGas recorded provisions of $18.9 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 $3.9 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 2.8 million shares priced at $35.69 per share and $230.5 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 OCI to income for the period;
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3.1 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 $12.0 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 $2.3 million;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $38.3 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 $10.9 million for certain hydro power development projects in British Columbia currently in a sale process; and
- 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.

Consolidated Balance Sheets

(condensed and unaudited)

As at *($ thousands)*	**September 30 2014**	December 31 2013
ASSETS		
Current assets		
Cash and cash equivalents	**$ 462,154**	$ 44,812
Accounts receivable, net of allowances	**225,075**	371,235
Inventory *(note 7)*	**167,629**	123,408
Restricted cash holdings from customers	**2,915**	2,662
Regulatory assets	**36,083**	6,046
Risk management assets *(note 10)*	**20,992**	34,988
Prepaid expenses and other current assets	**29,225**	33,224
Deferred income taxes	**3,561**	4,975
	947,634	621,350
Property, plant and equipment	**5,250,576**	4,952,526
Intangible assets *(note 11)*	**351,341**	195,259
Goodwill *(note 8)*	**767,978**	743,101
Regulatory assets	**244,359**	241,210
Risk management assets *(note 10)*	**9,700**	12,250
Deferred income taxes	**1,206**	836
Restricted cash holdings from customers	**11,768**	12,763
Long-term investments and other assets	**93,106**	25,864
Investments accounted for by equity method *(note 6)*	**464,283**	479,083
	$ 8,141,951	$ 7,284,242
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 269,937**	$ 321,921
Dividends payable	**19,636**	15,594
Short-term debt	**38,180**	84,350
Current portion of long-term debt *(note 9)*	**206,394**	209,069
Customer deposits	**34,066**	34,955
Regulatory liabilities	**1,604**	1,838
Risk management liabilities *(note 10)*	**20,860**	44,675
Deferred income taxes	**-**	508
Other current liabilities *(note 11)*	**19,104**	14,478
	609,781	727,388
Long-term debt *(note 9)*	**3,030,323**	2,952,673
Asset retirement obligations	**79,669**	76,125
Deferred income taxes	**463,001**	442,844
Regulatory liabilities	**132,505**	124,262
Risk management liabilities *(note 10)*	**7,147**	7,071
Other long-term liabilities *(note 11)*	**207,885**	52,584
Future employee obligations	**69,701**	71,825
	4,600,012	4,454,772

As at ($ thousands)	**September 30 2014**	December 31 2013
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 133.1 million issued and outstanding *(note 12)*	**2,725,059**	2,211,400
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 12)*	**194,126**	194,126
Preferred shares Series C cumulative redeemable five-year; par value US$25; authorized 8 million; 8 million issued and outstanding *(note 12)*	**200,626**	200,626
Preferred shares Series E cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 12)*	**194,495**	194,873
Preferred shares Series G cumulative redeemable five-year: par value $25; authorized 8 million; 8 million issued and outstanding (note 12)	**196,270**	-
Contributed surplus	**14,712**	13,350
Accumulated deficit	**(131,967)**	(62,148)
Accumulated other comprehensive income	**114,001**	39,480
Total shareholders' equity	**3,507,322**	2,791,707
Non-controlling interests	**34,617**	37,763
Total equity	**$ 3,541,939**	$ 2,829,470
	$ 8,141,951	$ 7,284,242

See accompanying notes to the condensed and unaudited Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ thousands except per share amounts)	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
REVENUE				
Sales	**$ 191,901**	$ 167,791	**$ 627,609**	$ 562,876
Services	**121,170**	105,103	**370,703**	296,121
Regulated operations	**130,838**	111,981	**744,331**	604,046
Other revenue (loss)	**(798)**	3,255	**(1,718)**	5,846
Unrealized gain (loss) on risk management contracts *(note* 10)	**1,062**	1,556	**(1,758)**	(7,122)
	444,173	389,686	**1,739,167**	1,461,767
EXPENSES				
Cost of sales, exclusive of items shown separately	**241,356**	211,435	**1,055,893**	900,981
Operating and administrative	**112,478**	105,149	**336,310**	312,921
Accretion expense	**2,001**	912	**4,077**	2,804
Depreciation, depletion and amortization	**43,607**	39,145	**126,578**	112,069
Provision for long-lived assets *(note 4)*	**-**	18,905	**49,197**	19,454
	399,442	375,546	**1,572,055**	1,348,229
Income from equity investments	**13,397**	30,088	**38,022**	96,252
Other income (expenses) *(note 5)*	**1,204**	38,177	**12,576**	38,482
Foreign exchange gain (loss)	**(505)**	197	**(270)**	201
Interest expense				
Short-term debt	**316**	275	**1,022**	1,420
Long-term debt	**28,291**	24,914	**75,913**	73,603
Income before income taxes	**30,220**	57,413	**140,505**	173,450
Income tax expense (recovery)				
Current	**(1,422)**	7,194	**12,584**	16,025
Deferred	**3,249**	280	**11,785**	9,575
Net income after taxes	**28,393**	49,939	**116,136**	147,850
Net income applicable to non-controlling interests	**1,998**	1,923	**6,164**	5,316
Net income applicable to controlling interests	**26,395**	48,016	**109,972**	142,534
Preferred share dividends	**9,760**	4,763	**24,557**	14,310
Net income applicable to common shares	**$ 16,635**	$ 43,253	**$ 85,415**	$ 128,224
Net income per common share *(note 13)*				
Basic	**$ 0.13**	$ 0.36	**$ 0.69**	$ 1.12
Diluted	**$ 0.13**	$ 0.35	**$ 0.68**	$ 1.09
Weighted average number of common shares outstanding *(note 12)* *(thousands)*				
Basic	**127,094**	118,653	**124,345**	114,066
Diluted	**129,200**	122,142	**126,351**	117,413

See accompanying notes to the condensed and unaudited Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(condensed and unaudited)

($ thousands)	Three months ended September 30 2014	2013	Nine months ended September 30 2014	2013
Net income after taxes	**$ 28,393**	$ 49,939	**$ 116,136**	$ 147,850
Total other comprehensive income (loss) (net of taxes)	**63,709**	(24,010)	**74,521**	20,112
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**$ 92,102**	$ 25,929	**$ 190,657**	$ 167,962
Comprehensive income attributable to:				
Non-controlling interests	**$ 1,998**	$ 1,923	**$ 6,164**	$ 5,316
Common shareholders	**90,104**	24,006	**184,493**	162,646
	$ 92,102	$ 25,929	**$ 190,657**	$ 167,962

Consolidated Accumulated Other Comprehensive Income (Loss) [1]

($ thousands)	Available-for-sale	Cash flow hedges	Defined benefit pension plans	Hedge net investments	Translation foreign operations	Total
Opening balance, January 1, 2014	$ (2,945)	$ (10,407)	$ (5,719)	$ (35,926)	$ 94,477	$ 39,480
Other comprehensive income (loss) before reclassification	2,052	7,383	131	(22,160)	87,076	74,482
Amounts reclassified from other comprehensive income *(note 3)*	-	(17)	56	-	-	39
Net current period other comprehensive income (loss)	$ 2,052	$ 7,366	$ 187	$ (22,160)	$ 87,076	$ 74,521
Ending balance, September 30, 2014[2] [3] [4] [5]	**$ (893)**	**$ (3,041)**	**$ (5,532)**	**$ (58,086)**	**$ 181,553**	**$ 114,001**
Opening balance, January 1, 2013	$ (5,787)	$ (994)	$ (10,246)	(2,263)	3,843	$ (15,447)
Other comprehensive income (loss) before reclassification	(882)	(2,610)	-	(16,328)	38,755	18,935
Amounts reclassified from other comprehensive income *(note 3)*	-	546	631	-	-	1,177
Net current period other comprehensive income (loss)	$ (882)	$ (2,064)	$ 631	(16,328)	38,755	$ 20,112
Ending balance, September 30, 2013[2] [3] [4] [5]	$ (6,669)	$ (3,058)	$ (9,615)	(18,591)	42,598	$ 4,665

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

(2) *Available-for-sale - net of tax recovery $ 140 (September 30, 2013 - tax recovery $751)*

(3) *Cash flow hedges - net of tax recovery $ 1,023 (September 30, 2013 - tax recovery $878).*

(4) *Defined benefit pension plans - net of tax recovery $ 1,821 (September 30, 2013 - tax recovery $2,259).*

(5) *Hedge net investment - net of tax recovery $ 8,366 (September 30, 2013 - tax recovery $2,341).*

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

($ thousands)	Nine months ended September 30 **2014**	2013
Common shares *(note 12)*		
Balance, beginning of year	**$ 2,211,400**	$ 1,639,895
Shares issued for cash on exercise of options	**17,550**	15,311
Shares issued under DRIP [1]	**49,665**	44,395
Shares issued on public offering	**446,444**	388,862
Balance, end of period	**2,725,059**	2,088,463
Preferred shares *(note 12)*		
Balance, beginning of year	**589,625**	394,752
Series E issued	**(378)**	-
Series G issued	**196,270**	-
Balance, end of period	**785,517**	394,752
Contributed surplus		
Balance, beginning of year	**13,350**	10,570
Share options expense	**3,000**	3,573
Exercise of share options	**(1,542)**	(1,073)
Forfeiture of share options	**(96)**	(558)
Balance, end of period	**14,712**	12,512
Accumulated deficit		
Balance, beginning of year	**(62,148)**	(69,979)
Net income applicable to controlling interests	**109,972**	142,534
Common share dividends	**(155,234)**	(126,937)
Preferred share dividends	**(24,557)**	(14,310)
Balance, end of period	**(131,967)**	(68,692)
Accumulated other comprehensive income (loss)		
Balance, beginning of year	**39,480**	(15,447)
Other comprehensive income	**74,521**	20,112
Balance, end of period	**114,001**	4,665
Total shareholders' equity	**3,507,322**	2,431,700
Non-controlling interests		
Balance, beginning of year	**37,763**	40,006
Net income applicable to non-controlling interests	**6,164**	5,316
Distribution by subsidiaries to non-controlling interests	**(9,310)**	(1,912)
Balance, end of period	**34,617**	43,410
Total equity	**$ 3,541,939**	$ 2,475,110

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

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

($ thousands)	Three months ended September 30 2014	2013	Nine months ended September 30 2014	2013
Cash from operations				
Net income after taxes	**$ 28,393**	$ 49,939	**$ 116,136**	$ 147,850
Items not involving cash:				
Depreciation, depletion and amortization	**43,607**	39,145	**126,578**	112,069
Provision for long-lived assets	**-**	18,905	**49,197**	19,454
Accretion expense	**2,001**	912	**4,077**	2,804
Share-based compensation	**945**	1,007	**2,904**	3,016
Deferred income tax expense	**3,249**	280	**11,785**	9,575
(Gain) Loss on sale of assets	**27**	(37,501)	**(11,113)**	(37,513)
Income from equity investments	**(13,397)**	(30,088)	**(38,022)**	(96,252)
Unrealized (gain) loss on risk management contracts	**(1,062)**	(1,556)	**1,758**	7,122
Unrealized (gain) loss on long-term investments	**346**	173	**(86)**	1,122
Other	**1,601**	562	**896**	2,792
Asset retirement obligations settled	**(316)**	(194)	**(997)**	(844)
Distributions from equity investments	**14,137**	38,235	**51,381**	105,795
Changes in operating assets and liabilities:				
Accounts receivable	**(1,679)**	33,063	**151,265**	152,567
Inventory	**(58,054)**	(33,679)	**(38,634)**	(45,772)
Other current assets	**(6,116)**	(4,141)	**4,763**	(2,763)
Regulatory assets (current)	**4,015**	(2,216)	**(29,930)**	(1,017)
Accounts payable and accrued liabilities	**31,613**	59,891	**(43,078)**	(12,105)
Customer deposits	**12,596**	11,402	**(2,235)**	(3,253)
Regulatory liabilities (current)	**1,017**	(2,755)	**(314)**	100
Other current liabilities	**1,621**	3,357	**(5,292)**	1,507
Other operating assets and liabilities	**8,591**	9,961	**5,496**	24,328
	73,135	154,702	**356,535**	390,582
Investing activities				
Change in restricted cash holdings from customers	**127**	3,037	**(105)**	5,718
Acquisition of property, plant and equipment	**(151,677)**	(196,074)	**(388,350)**	(419,138)
Acquisition of intangible assets	**(10,338)**	(35,707)	**(19,781)**	(40,764)
Proceeds from dispositions of assets	**(209)**	39,081	**27,202**	39,449
Acquisition of long-term investments (note 10)	**(50,000)**	-	**(50,000)**	-
Contributions to equity investments	**(2,838)**	(1,910)	**(6,762)**	(2,253)
Business acquisitions, net of cash acquired	**-**	-	**5,031**	(536,802)
	(214,935)	(191,573)	**(432,765)**	(953,790)

($ thousands)	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Financing activities				
Net issuance (repayment) of short-term debt	**10,374**	2,492	**(49,545)**	(59,425)
Issuance of long-term debt, net of debt issuance costs	**300,563**	122,563	**1,046,799**	1,155,591
Repayment of long-term debt	**(326,802)**	(89,819)	**(1,022,434)**	(791,395)
Dividends - common shares	**(54,767)**	(44,759)	**(151,192)**	(124,415)
Dividends - preferred shares	**(9,760)**	(4,763)	**(25,029)**	(14,310)
Distributions to non-controlling interest	**(3,063)**	(1,028)	**(9,310)**	(1,912)
Net proceeds from shares issued on exercise of options	**2,667**	1,837	**16,008**	15,312
Net proceeds from issuance of common shares	**459,732**	15,555	**491,455**	432,186
Net proceeds from issuance of preferred shares	**194,985**	-	**194,517**	-
	573,929	2,078	**491,269**	611,632
Effect of exchange rate changes on cash and cash equivalents	**2,142**	(196)	**2,303**	290
Change in cash and cash equivalents	**432,129**	(34,793)	**415,039**	48,424
Cash and cash equivalents, beginning of year	**27,883**	95,530	**44,812**	11,827
Cash and cash equivalents, end of period	**$ 462,154**	$ 60,541	**$ 462,154**	$ 60,541

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

($ thousands)	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Interest paid (net of capitalized interest)	**$ 29,922**	$ 21,440	**$ 73,581**	$ 68,817
Income taxes paid	**$ 2,453**	$ 1,390	**$ 14,354**	$ 6,245

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Notes to the Condensed Unaudited Interim Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in thousands 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 (U.S.) 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, the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas). AIJVLP also manages the liquefied petroleum gas (LPG or propane) and the liquefied natural gas (LNG) export development projects.

The Power segment includes 1,294 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and United States, along with the Northwest Projects additional 82 MW of run-of-river assets under construction in British Columbia. On August 12, 2014, the 195 MW Forrest Kerr run-of-river hydroelectric facility was brought into service.

The Utilities segment is predominantly comprised of natural gas distribution rate-regulated utilities. AltaGas owns and operates regulated natural gas utilities in Canada and 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 condensed unaudited interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP) for interim financial statements. As a result, these condensed unaudited 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 2013 annual audited Consolidated Financial Statements prepared in accordance with US GAAP. In management's opinion, the condensed unaudited 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 U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date on 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 condensed unaudited 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 by 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 unaudited Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2013 US GAAP annual audited Consolidated Financial Statements, except, as described below, for the exchange rates used.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency for domestic entities are converted at the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statement of Income. Non-monetary assets and liabilities are converted at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. The exchange rate used to convert a US dollar to a Canadian dollar as at September 30, 2014 was 1.1208 (as at December 31, 2013 - 1.0636).

Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI. The average exchange rate used to convert a US dollar to a Canadian dollar for the nine months period ended September 30, 2014 was 1.0944 (nine months ended September 30, 2013 - 1.0236).

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.

RECENTLY ADOPTED ACCOUNTING PRINCIPLES

In April 2014, FASB issued ASU No. 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity". The amendments in this Update improve the definition of discontinued operations by limiting the discontinued operations to the disposals of components of an entity that represent a strategic shift that have (or will have) a major effect on an entity's operations and financial results. The amendments are effective for all disposals (or classification as held for sale) of components of an entity that occur within annual periods beginning on or after December 15, 2014 and interim periods within those periods. Early adoption is permitted for disposals (or classification as held for sale) that have not been reported in financial statements previously issued or available for issuance.

AltaGas adopted the Update beginning on July 1, 2014, with no impact in the preparation and presentation of its condensed unaudited consolidated financial statements.

CHANGE IN ACCOUNTING POLICIES

In January 2014, FASB issued ASU No. 2014-05, "Service Concession Arrangements". The amendments in this Update provide guidance for accounting for service concession arrangements, previously not covered by US GAAP. A service concession arrangement is an arrangement between a public-sector entity grantor and an operating entity under which the operating entity operates the grantor's infrastructure. The amendments in this Update should be applied on a modified retrospective basis to service concession arrangements that exist at the beginning of an entity's fiscal year of adoption with a cumulative effect recognized as an adjustment to the opening retained earnings balance for the annual period of adoption. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2014. AltaGas will adopt the Update for the financial periods beginning on January 1, 2015. The adoption of this Update does not have any impact for the preparation and presentation of AltaGas' consolidated financial statements.

In May 2014, FASB issued 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. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. Early adoption is not permitted. AltaGas commenced a process for the adoption of the Update. The impacts in the recognition, measurement and presentation of revenue from contracts with customers in accordance with the Update are under assessment for AltaGas' consolidated financial statements.

In June 2014, FASB issued ASU No. 2014-12, "Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period". The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2015. Early adoption is permitted. AltaGas will adopt the Update for the financial periods beginning on January 1, 2016. AltaGas does not expect any material impact in the preparation and presentation of its consolidated financial statements.

3. RECLASSIFICATION FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

AOCI components reclassified	Income Statement line item	**Three months ended September 30, 2014**	**Nine months ended September 30, 2014**
Cash flow hedges			
NGL (ineffective hedge)	Unrealized (losses) on risk management contracts	**$ (1,308)**	**$ (370)**
Bond forward	Interest expense – Long-term debt	**-**	**64**
	Other income (expenses)	**-**	**196**
Defined benefit pension plans	Operating and administrative expense	**142**	**294**
	Total before income taxes	**(1,166)**	**184**
Deferred income taxes	Income tax expenses – Deferred	**294**	**(145)**
		$ (872)	**$ 39**

AOCI components reclassified	Income Statement line item	Three months ended September 30, 2013	Nine months ended September 30, 2013
Cash flow hedges			
Bond forward	Interest expense – Long-term debt	$ 186	$ 546
Defined benefit pension plans	Operating and administrative expense	204	850
	Total before income taxes	390	1,396
Deferred income taxes	Income tax expenses – Deferred	(40)	(219)
		$ 350	$ 1,177

4. PROVISION FOR LONG-LIVED ASSETS

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Gas (a)	**-**	$ (15,904)	**$ (38,337)**	$ (15,904)
Power (b)	**-**	-	**(10,860)**	(549)
Utilities (c)	**-**	(3,000)	**-**	(3,000)
	-	$ (18,904)	**$ (49,197)**	$ (19,453)

(a) Total provisions in 2014 include $19.6 million for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and $18.7 million for related Transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements. Total provisions in 2013 includes $15.9 million for certain non-core assets that AltaGas expects to sell.

(b) The total provision in 2014 of $10.9 million relates to certain hydro power assets under development in British Columbia. AltaGas is in discussions with a third party to sell these smaller hydro projects currently under development, and indicative values resulted in the write down of the assets to the current estimated fair value. The total provision in 2013 of $0.5 million relates to a write-off of a gas peaking plant.

(c) The total provision in 2013 of $3.0 million relates to jointly-owned assets of the Canadian Utilities in the Northwest Territories, resulting from the expected undiscounted cash flows being lower than the carrying value of these assets.

5. OTHER INCOME (EXPENSES)

On February 12, 2014, AltaGas sold Ante Creek, a 58.5 Mmcf/d (licensed capacity) gas processing facility located near Sturgeon Lake, northwestern Alberta, with a realized pre-tax gain of $12.0 million.

On February 14, 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 $2.3 million.

On March 2, 2011, Pacific Northern Gas Ltd. (PNG) sold its 50 percent interest in Pacific Trail Pipelines Limited Partnership (PTP), subject to a contingent reversionary right at the end of 2013. The purchase price of $50 million was to be paid in two tranches. The first tranche of $30 million was paid to PNG on closing in March 2011 while the remaining $20 million was to be paid upon the buyers' advising PNG that they had issued a notice to proceed with respect to the construction of the Kitimat LNG project. On May 23, 2013 PNG and the buyers amended the acquisition agreement by increasing the second payment from $20 million to $38 million and removing the contingent reversionary right. During third quarter 2013, PNG received regulatory approval for the amendment, received payment of the consideration from the buyers and recognized a $37.5 million pre-tax gain on the transaction.

6. BUSINESS ACQUISITION

Petrogas

On October 1, 2013, AltaGas completed the acquisition of a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. Petrogas is engaged in the marketing, storage, and distribution of natural gas liquids, drilling fluids, fracing fluids, crude oil and condensate diluents. Petrogas and its subsidiaries own underground storage facilities, own and lease surface storage, and own and operate processing plants, truck and transportation equipment, loading and terminaling facilities and crude oil blending facilities. AltaGas paid for the acquisition with approximately 2.8 million common shares priced at $35.69 per share and $230.5 million of cash. The investment was accounted for using the equity method.

On October 24, 2013, AltaGas announced it planned to increase its effective ownership of Petrogas to 33 1/3 percent, exercising a call option included in the share purchase agreement with the vendor.

On March 1, 2014, AltaGas transferred its 25 percent ownership interest to AIJVLP. On March 1, 2014, AIJVLP acquired an additional 41 2/3 percent interest in Petrogas for $300.8 million cash consideration and a $250.0 million note payable to the vendor. As a result of the transaction, Petrogas is effectively owned one-third by each of AltaGas, Idemitsu Kosan Co., Ltd. (Idemitsu), and its former majority shareholder.

7. INVENTORY

As at		**September 30 2014**		December 31 2013
Natural gas held in storage	**$**	**147,427**	$	106,715
Other inventory		**20,202**		16,693
	$	**167,629**	$	123,408

8. GOODWILL

As at		**September 30 2014**		December 31 2013
Balance, beginning of period	**$**	**743,101**	$	714,902
Foreign exchange translation		**24,877**		29,878
Other changes		**-**		(1,679)
	$	**767,978**	$	743,101

9. LONG-TERM DEBT

	Maturity date	**September 30 2014**	December 31 2013
Credit facilities			
$1,400 million Unsecured extendible revolving (a)	15-Dec-2017	**-**	578,566
Medium-term notes			
$200 million Senior unsecured - 7.42 percent	29-Apr-2014	**-**	200,000
$200 million Senior unsecured - 4.10 percent	24-Mar-2016	**200,000**	200,000
$100 million Senior unsecured - 6.94 percent	29-Jun-2016	**100,000**	100,000
$200 million Senior unsecured - 5.49 percent	27-Mar-2017	**200,000**	200,000
$175 million Senior unsecured - 4.60 percent	15-Jan-2018	**175,000**	175,000
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**200,000**	200,000
$200 million Senior unsecured - 4.07 percent	01-Jun-2020	**200,000**	200,000
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350,000**	350,000
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300,000**	300,000
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200,000**	-
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100,000**	-
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**299,805**	-
US$175 million Senior unsecured - floating (b)	13-Apr-2015	**196,140**	186,130
US$200 million Senior unsecured - floating (c)	24-Mar-2016	**224,160**	-
SEMCO long-term debt			
US$90 million CINGSA Secured construction and term loan (d)	14-Nov-2015	**-**	86,258
US$82 million CINGSA Senior secured - 4.48 percent (e)	2-Mar-2032	**91,906**	**-**
US$300 million SEMCO Senior secured - 5.15 percent (f)	21-Apr-2020	**336,240**	319,080
Debenture notes			
PNG RoyNat Debenture - 3.75 percent (g)	15-Sep-2017	**10,100**	11,000
PNG 2018 Series Debenture - 8.75 percent (g)	15-Nov-2018	**11,000**	11,000
PNG 2024 CFI Debenture - 7.39 percent (h)	01-Nov-2024	**7,535**	7,899
PNG 2025 Series Debenture - 9.30 percent (g)	18-Jul-2025	**14,500**	15,000
PNG 2027 Series Debenture - 6.90 percent (g)	02-Dec-2027	**16,000**	16,000
Loan from Province of Nova Scotia (i)	31-Jul-2016	**2,060**	3,060
SEMCO capital lease obligation - 3.50 percent	01-May-2040	**652**	471
Promissory notes	25-Oct-2015	**1,460**	1,946
Other long-term debt		**159**	332
		3,236,717	3,161,742
Less current portion		**206,394**	209,069
		3,030,323	$ 2,952,673

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. Letters of credit outstanding as at September 30, 2014 were NIL (December 31, 2013 - $19.0 million)

(b) The notes carry 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 loan was repaid on June 10, 2014.

(e) Collateral for the US$82 million CINGSA Senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

(f) Collateral for the US$300 million MTNs is certain SEMCO Energy, Inc. (SEMCO) assets.

(g) 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.

(h) 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 in McNair Creek.

(i) 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.

10. 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 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 value of power, natural gas and NGL derivatives was calculated using estimated 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:

Cash, Cash Equivalents, 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 and Long-term Debt - the fair value of current portion of long-term debt and long-term debt have been estimated based on discounted future interest and principal payments using estimated interest rates.

Summary of Fair Values	**September 30 2014**	December 31 2013
Current portion of long-term debt		
Carrying amount	**$ 206,394**	$ 209,069
Fair value of current portion of long-term debt	**$ 206,513**	$ 212,354

Summary of Fair Values	**September 30 2014**	December 31 2013
Long-term debt excluding non-financial instruments		
Carrying amount	**$ 3,030,323**	$ 2,952,673
Fair value of long-term debt	**$ 3,345,396**	$ 3,062,636

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 inputs other than quoted prices that are observable for the asset or liability. 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.

September 30, 2014	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	**$ 462,154**	**-**	**-**	**$ 462,154**
Risk management assets - current	**-**	**$ 20,992**	**-**	**$ 20,992**
Risk management assets - non-current	**-**	**$ 9,700**	**-**	**$ 9,700**
Long-term investments and other assets (1)	**$ 57,649**	**-**	**-**	**$ 57,649**
Financial liabilities				
Risk management liabilities - current	**-**	**$ 20,860**	**-**	**$ 20,860**
Risk management liabilities - non-current	**-**	**$ 7,147**	**-**	**$ 7,147**
Other long-term liabilities (2)	**-**	**154,008**	**-**	**154,008**
Current portion of long-term debt	**-**	**$ 206,513**	**-**	**$ 206,513**
Long-term debt	**-**	**$ 3,345,396**	**-**	**$ 3,345,396**
December 31, 2013	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	$ 44,812	-	-	$ 44,812
Risk management assets - current	-	$ 34,988	-	$ 34,988
Risk management assets - non-current	-	$ 12,250	-	$ 12,250
Long-term investments and other assets	$ 5,365	-	-	$ 5,365
Financial Liabilities				
Risk management liabilities - current	-	$ 44,675	-	$ 44,675
Risk management liabilities - non-current	-	$ 7,071	-	$ 7,071
Other long-term liabilities (2)	-	-	-	-
Current portion of long-term debt	-	$ 212,354	-	$ 212,354
Long-term debt	-	$ 3,062,636	-	$ 3,062,636

(1) *Excludes non-financial assets and financial assets carried at cost.*

(2) *Excludes non-financial liabilities.*

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

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Natural Gas	**$ 548**	$ 692	**$ (472)**	$ (1,141)
Storage Optimization	**(463)**	(248)	**327**	(165)
NGL Frac Spread	**1,307**	(3,487)	**370**	(3,741)
Power	**(240)**	3,935	**(1,714)**	(1,462)
Heat Rate	**162**	549	**(137)**	282
Foreign Exchange	**5**	116	**112**	(429)
Embedded Derivative	**(257)**	(1)	**(244)**	(466)
	$ 1,062	$ 1,556	**$ (1,758)**	$ (7,122)

Summary of Unrealized Gains (Losses) and Tax Recovery (Expense) on Financial Instruments Recognized in Accumulated Other Comprehensive Income

	Unrealized losses	Tax recovery	Nine months ended September 30 2014	Unrealized gains (losses)	Tax recovery	Nine months ended September 30 2013
Available-for-sale	**$ 2,338**	**$ (286)**	**$ 2,052**	$ (1,004)	$ 122	$ (882)
Bond Forward	**260**	**-**	**260**	546	-	546
NGL Frac Spread	**9,498**	**(2,392)**	**7,106**	(3,488)	878	(2,610)
AOCI	**$ 12,096**	**$ (2,678)**	**$ 9,418**	$ (3,946)	$ 1,000	$ (2,946)

Offsetting of Derivative Assets and Derivative Liabilities

As at September 30, 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	**$ 53,430**	**$ 36,219**	**$ 17,211**
Storage Optimization	**460**	**253**	**207**
Total	**$ 53,890**	**$ 36,472**	**$ 17,418**
Risk management liabilities (2)			
Natural Gas	**$ 49,786**	**$ 36,219**	**$ 13,567**
Storage Optimization	**1,349**	**253**	**1,096**
Total	**$ 51,135**	**$ 36,472**	**$ 14,663**

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $11,500 and risk management assets (non-current) balance of $5,918.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $10,791 and risk management liabilities (non-current) balance of $3,872.*

As at September 30, 2013

Risk management assets (1)	Gross amounts of recognized assets/liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	$ 49,637	$ 36,219	$ 13,418
Storage optimization	457	253	204
Total	$ 50,094	$ 36,472	$ 13,622
Risk management liabilities (2)			
Natural gas	$ 45,910	$ 36,219	$ 9,691
Storage optimization	390	253	137
Total	$ 46,300	$ 36,472	$ 9,828

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $8,500 and risk management assets (non-current) balance of $5,122.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $6,028 and risk management liabilities (non-current) balance of $3,800.*

Offsetting of fair value amounts is generally not applied except where a right of set-off exists. A right of set-off exists only when AltaGas and its counterparty in the financial instrument owe a determinate amount, the two parties agree to set-off the amounts due, AltaGas intends to set-off, and the right of set-off is enforceable by law.

Long-term Investments and Other Assets

In January 2009, AltaGas purchased 8,000,000 common shares of Alterra Power Corp. (Alterra), through a private equity offering. In August 2014, AltaGas purchased 4,166,666 common shares of Painted Pony Petroleum Ltd. (Painted Pony) for a total consideration of $50 million. Pursuant to the terms of the private placement, the common shares of Painted Pony subscribed for by AltaGas are subject to a one-year hold period restriction.

Alterra and Painted Pony shares were classified as available-for-sale. The investments classified as available-for-sale also include funds under trust, acquired with SEMCO. The after-tax accumulated changes in fair value of these financial assets are being reported in AOCI.

Summary of After-tax Unrealized Gains (Losses) on Available-for-sale Recognized in AOCI

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Changes in fair value	**$ 1,710**	$ (162)	**$ 2,052**	$ (903)
	$ 1,710	$ (162)	**$ 2,052**	$ (903)

In July 2009, AltaGas purchased additional shares of Alterra as part of its initial public offering, which were classified as held-for-trading. In July 2010, AltaGas purchased a second tranche of common shares in Alterra, which were also classified as held-for-trading.

Unrealized gains (losses) on held-for-trading are recognized in the Consolidated Statement of Income under "Other income (expense)".

Summary of Unrealized Gains (Losses) on Held-for-trading Recognized in Net Income

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Financial assets held-for-trading	**$ (346)**	$ (173)	**$ 86**	$ (1,122)

AltaGas' available-for-sale and held-for-trading investments are reported under "Long-term investment and other assets" in the Consolidated Balance Sheet.

11. NORTHWEST TRANSMISSION LINE

In 2010, AltaGas entered into a 60-year CPI indexed 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 was measured using an estimated inflation rate and 4.27 percent discount rate. This fair value has been recorded within other current liabilities for $10.4 million and other long-term liabilities for $154.0 million. 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 shall be depreciated over 60 years, the term of the EPA with BC Hydro.

12. SHAREHOLDERS' EQUITY

Authorization

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

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2013	105,336,884	$	1,639,895
Shares issued for cash on exercise of options	806,093		18,916
Shares issued under DRIP	1,745,411		60,305
Shares issued on private issuance	2,801,905		100,000
Shares issued on public offering	11,615,000		392,284
December 31, 2013	122,305,293	$	2,211,400
Shares issued for cash on exercise of options	**671,435**		**17,550**
Shares issued on public offering	**9,027,500**		**446,444**
Shares issued under DRIP	**1,124,288**		**49,665**
Issued and outstanding at September 30, 2014	**133,128,516**	**$**	**2,725,059**

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2011	8,000,000	$	194,126
January 1, 2013	8,000,000		194,126
December 31, 2013	8,000,000		194,126
Issued and outstanding at September 30, 2014	**8,000,000**	**$**	**194,126**

Preferred Shares Series C Issued and Outstanding	Number of shares		Amount
January 1, 2013	8,000,000		200,626
December 31, 2013	8,000,000		200,626
Issued and outstanding at September 30, 2014	**8,000,000**	**$**	**200,626**

Preferred Shares Series E Issued and Outstanding	Number of shares		Amount
January 1, 2013	**-**		-
Shares issued on public offering	8,000,000		194,873
December 31, 2013	8,000,000		194,873
Share issuance costs (1)	**-**		**(378)**
Issued and outstanding at September 30, 2014	**8,000,000**	**$**	**194,495**

(1) *Net of tax recovery $121*

Preferred Shares Series G Issued and Outstanding	Number of shares		Amount
January 1, 2014	**-**		-
Shares issued on public offering	8,000,000		**200,000**
Share issuance costs (2)	**-**		**(3,730)**
Issued and outstanding at September 30, 2014	**8,000,000**	**$**	**196,270**

(2) *Net of tax recovery $1,255*

Weighted Average Shares Outstanding	Three months ended September 30 **2014**	2013	Nine months ended September 30 **2014**	2013
Number of shares - basic	**127,093,675**	118,653,074	**124,345,331**	114,065,761
Dilutive equity instruments [1]	**2,106,066**	3,488,857	**2,006,040**	3,347,282
Number of shares - diluted	**129,199,741**	122,141,931	**126,351,371**	117,413,043

[1] *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at September 30, 2014 and 2013, respectively.*

For the nine months ended September 30, 2014, 114,000 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (September 30, 2013 - 731,000 options).

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at September 30, 2014, 8,357,969 shares were reserved for issuance under the plan. As at September 30, 2014, options granted under the plan have a term between 6 and 10 years until expiry and vest no longer than over a four-year period. As at September 30, 2014, unexpensed fair value of share option compensation cost associated with future periods was $ 3.7 million (December 31, 2013 - $6.2 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, 2013	5,561,505	$ 27.25
Granted	132,000	45.82
Exercised	(671,435)	23.84
Forfeited	(67,188)	34.96
Share options outstanding, September 30, 2014	**4,954,882**	**$ 28.10**
Share options exercisable, September 30, 2014	**2,591,207**	**$ 23.88**

[1] *Weighted average.*

The following table summarizes the employee share option plan as at September 30, 2014:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Exercise price
$13.65 to $18.00	441,270	$ 15.81	4.74	441,270	$ 15.81
$18.01 to $25.08	1,269,050	20.85	5.42	1,027,438	20.75
$25.09 to $49.20	3,244,562	32.61	6.77	1,122,499	29.91
	4,954,882	**$ 28.10**	**6.24**	**2,591,207**	**$ 23.88**

Equity-based Compensation Plan

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. The phantom shares are valued based on dividends declared and the trading price of the Corporation's common shares. The shares vest on a graded vesting schedule over a term between 36 and 44 months. For the nine months ended September 30, 2014, the compensation expense recorded was $4.0 million (nine months ended September 30, 2013 - $2.2 million). As at September 30, 2014, the unexpensed fair value of equity-based compensation cost associated with future periods was $16.5 million (December 31, 2013 - $9.2 million).

13. NET INCOME APPLICABLE TO COMMON SHARES

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

	Three months ended		Nine months ended	
	September 30 2014	September 30 2013	**September 30 2014**	September 30 2013
Numerator:				
Net income applicable to controlling interests	**$ 26,395**	$ 48,016	**$ 109,972**	$ 142,534
Less: Preferred share dividends	**9,760**	4,763	**24,557**	14,310
Net income applicable to common shares	**$ 16,635**	$ 43,253	**$ 85,415**	$ 128,224
Net income applicable to common shares - diluted	**$ 16,635**	$ 43,253	**$ 85,415**	$ 128,224
Denominator:				
Weighted average number of common shares outstanding	**127,094**	118,653	**124,345**	114,066
Dilutive equity instruments(1)	**2,106**	3,489	**2,006**	3,347
Weighted average number of common shares outstanding - diluted	**129,200**	122,142	**126,351**	117,413
Basic net income applicable per common share	**$ 0.13**	$ 0.36	**$ 0.69**	$ 1.12
Diluted net income applicable per common share	**$ 0.13**	$ 0.35	**$ 0.68**	$ 1.09

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at September 30, 2014 and 2013.*

14. 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 2014 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 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 $13.3 million over the next 8 years, of which $9.4 million is payable in 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.

15. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality 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 September 30, 2014	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**
Current service cost	**$ 1,428**	**$ 124**	**$ 1,351**	**$ 338**	**$ 2,779**	**$ 462**
Interest cost	**1,292**	**144**	**2,277**	**767**	**3,569**	**911**
Expected return on plan assets	**(1,156)**	**(31)**	**(3,008)**	**(954)**	**(4,164)**	**(985)**
Amortization of past service cost	**20**	**-**	**14**	**(62)**	**34**	**(62)**
Amortization of net actuarial loss	**137**	**4**	**197**	**65**	**334**	**69**
Amortization of regulatory asset	**208**	**7**	**454**	**112**	**662**	**119**
Net benefit cost recognized	**$ 1,929**	**$ 248**	**$ 1,285**	**$ 266**	**$ 3,214**	**$ 514**

	Canada		United States		Total	
Nine months ended September 30, 2014	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**
Current service cost	**$ 4,285**	**$ 372**	**$ 4,071**	**$ 1,019**	**$ 8,356**	**$ 1,391**
Interest cost	**3,877**	**431**	**6,863**	**2,312**	**10,740**	**2,743**
Expected return on plan assets	**(3,469)**	**(93)**	**(9,068)**	**(2,875)**	**(12,537)**	**(2,968)**
Amortization of past service cost	**58**	**-**	**40**	**(187)**	**98**	**(187)**
Amortization of net actuarial loss	**410**	**14**	**595**	**195**	**1,005**	**209**
Amortization of regulatory asset	**625**	**20**	**1,369**	**338**	**1,994**	**358**
Net benefit cost recognized	**$ 5,786**	**$ 744**	**$ 3,870**	**$ 802**	**$ 9,656**	**$ 1,546**

	Canada		United States		Total	
Three months ended September 30, 2013	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost	$ 1,573	$ 153	$ 1,524	$ 310	$ 3,097	$ 463
Interest cost	1,136	146	1,845	548	2,981	694
Expected return on plan assets	(944)	(18)	(2,467)	(815)	(3,411)	(833)
Cost of special events	-	-	60	-	60	-
Amortization of past service cost	19	-	12	(58)	31	(58)
Amortization of net actuarial loss	273	13	977	131	1,250	144
Amortization of regulatory asset	320	54	425	104	745	158
Net benefit cost recognized	$ 2,377	$ 348	$ 2,376	$ 220	$ 4,753	$ 568

Nine months ended September 30, 2013	Canada Defined Benefit	Canada Post-retirement Benefits	United States Defined Benefit	United States Post-retirement Benefits	Total Defined Benefit	Total Post-retirement Benefits
Current service cost	$ 4,719	$ 465	$ 4,572	$ 925	$ 9,291	$ 1,390
Interest cost	3,414	436	5,531	1,645	8,945	2,081
Expected return on plan assets	(2,836)	(56)	(7,397)	(2,443)	(10,233)	(2,499)
Cost of special events	-	-	182	-	182	-
Amortization of past service cost	57	-	37	(174)	94	(174)
Amortization of net actuarial loss	817	37	2,932	396	3,749	433
Amortization of regulatory asset	964	162	1,272	314	2,236	476
Net benefit cost recognized	$ 7,135	$ 1,044	$ 7,129	$ 663	$ 14,264	$ 1,707

16. COMPARATIVE FIGURES

Certain comparative figures related to income tax liabilities for the three and nine months period ended September 30, 2013 and for the year ended December 31, 2013 have been reclassified to conform to the presentation adopted in the current year.

17. SEASONALITY

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

On August 12, 2014, the Forrest Kerr run-of-river hydroelectricity facility was brought into service. The production from this facility is highly seasonal, resulting in the strongest results in the third and fourth quarters, due to the seasonal nature of the river-flows on the Iskut river. The seasonality of revenue generation from Forrest Kerr is expected to partially offset the seasonality of the utility business.

18. SEGMENTED INFORMATION

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

Gas	– NGL processing and extraction plants; – transmission pipelines to transport natural gas and NGL; – natural gas gathering lines and field processing facilities; – purchase and sale of natural gas and electricity; – natural gas storage facilities; – LNG and LPG development projects; and – Equity investment 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 and a power purchase arrangement, both operational and under construction; – gas-fired power plants in Alberta; – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
Corporate	– the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

The following tables show the composition by segment:

Three months ended September 30, 2014 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 235,701	$ 102,339	$ 132,192	-	$ (27,121)	$ 443,111
Unrealized loss on risk management	-	-	-	1,062	-	1,062
Cost of sales	(139,030)	(66,734)	(60,747)	-	25,155	(241,356)
Operating and administrative	(46,830)	(12,275)	(48,851)	(6,488)	1,966	(112,478)
Accretion expense	(933)	(1,047)	(21)	-	-	(2,001)
Depreciation, depletion and amortization	(16,562)	(10,410)	(15,845)	(790)	-	(43,607)
Provision for long-lived assets	-	-	-	-	-	-
Income from equity investments	6,001	7,353	43	-	-	13,397
Other income (expenses)	(58)	36	1,001	225	-	1,204
Foreign exchange gain (loss)	-	-	-	(505)	-	(505)
Interest expense	-	-	-	(28,607)	-	(28,607)
Income (loss) before income taxes	$ 38,289	$ 19,262	$ 7,772	$ (35,103)	-	$ 30,220
Net additions (reductions) to:						
Property, plant and equipment[1]	$ 17,877	$ 91,464	$ 91,074	$ 492	-	$ 200,907
Intangible assets	$ 2,081	$ 169,381	$ 1,329	$ 4,415	-	$ 177,206

[1] *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 foreign exchange changes on U.S. assets.*

Nine months ended September 30, 2014 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 887,190	$ 283,628	$ 748,867	$ -	$ (178,760)	$ 1,740,925
Unrealized gain on risk management	-	-	-	(1,758)	-	(1,758)
Cost of sales	(591,295)	(189,711)	(447,445)	-	172,558	(1,055,893)
Operating and administrative	(137,881)	(35,864)	(147,950)	(20,817)	6,202	(336,310)
Accretion expense	(2,800)	(1,214)	(63)	-	-	(4,077)
Depreciation, depletion and amortization	(50,164)	(26,486)	(47,687)	(2,241)	-	(126,578)
Provision for long-lived assets	(38,337)	(10,860)	-	-	-	(49,197)
Income from equity investments	19,354	17,893	775	-	-	38,022
Other income (expense)	11,966	(80)	2,354	(1,664)	-	12,576
Foreign exchange gain (loss)	-	-	-	(270)	-	(270)
Interest expense	-	-	-	(76,935)	-	(76,935)
Income (loss) before income taxes	$ 98,033	$ 37,306	$ 108,851	$ (103,685)	-	$ 140,505
Net additions (reductions) to:						
Property, plant and equipment[1]	$ 16,496	$ 254,356	$ 147,546	$ 4,179	-	$ 422,577
Intangible assets	$ 2,081	$ 170,042	$ 1,329	$ 6,178	-	$ 179,630
As at September 30, 2014						
Goodwill	161,401	-	606,577	-	-	$ 767,978
Segmented assets	$ 2,361,179	$ 2,307,344	$ 2,863,390	$ 610,038	-	$ 8,141,951

Three months ended September 30, 2013 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 206,394	$ 79,876	$ 111,779	-	$ (9,919)	$ 388,130
Unrealized gain on risk management	-	-	-	1,556	-	1,556
Cost of sales	(117,472)	(56,809)	(46,341)	-	9,187	(211,435)
Operating and administrative	(44,953)	(9,102)	(45,242)	(6,583)	732	(105,148)
Accretion expense	(880)	(32)	-	-	-	(912)
Depreciation, depletion and amortization	(16,890)	(7,198)	(14,015)	(1,042)	-	(39,145)
Provision for long-lived assets	(15,905)	-	(3,000)	-	-	(18,905)
Income from equity investments	(1,254)	30,818	524	-	-	30,088
Other income	(134)	-	38,246	64	-	38,176
Foreign exchange gain	-	-	-	197	-	197
Interest expense	-	-	-	(25,189)	-	(25,189)
Income (loss) before income taxes	$ 8,906	$ 37,553	$ 41,951	$ (30,997)	-	$ 57,413
Net additions (reductions) to:						
Property, plant and equipment[(1)]	$ (16,873)	$ 88,230	$ 16,916	$ (2,624)	-	$ 85,649
Intangible assets	$ 246	$ (55)	$ 1,113	$ 8,097	-	$ 9,401

[(1)] *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 U.S. assets.*

Nine months ended September 30, 2013 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 748,125	$ 212,070	$ 604,092	-	$ (95,398)	$ 1,468,889
Unrealized loss on risk management	-	-	-	(7,122)	-	(7,122)
Cost of sales	(480,421)	(178,474)	(333,353)	-	91,267	(900,981)
Operating and administrative	(139,450)	(21,945)	(137,857)	(17,800)	4,131	(312,921)
Accretion expense	(2,695)	(95)	(14)	-	-	(2,804)
Depreciation, depletion and amortization	(51,707)	(15,408)	(41,874)	(3,080)	-	(112,069)
Provision for long-lived assets	(15,905)	(549)	(3,000)	-	-	(19,454)
Income from equity investments	(958)	95,542	1,668	-	-	96,252
Other income (expenses)	10	-	39,162	(690)	-	38,482
Foreign exchange gain	-	-	-	201	-	201
Interest expense	-	-	-	(75,023)	-	(75,023)
Income (loss) before income taxes	$ 56,999	$ 91,141	$ 128,824	$ (103,514)	-	$ 173,450
Net additions (reductions) to:						
Property, plant and equipment[(1)]	$ (2,317)	$ 806,770	$ 116,488	$ 235	-	$ 921,176
Intangible assets	$ 3,603	$ (153)	$ 4,000	$ 7,114	-	$ 14,564
As at September 30, 2013						
Goodwill	$ 161,401	-	$ 566,435	-	-	$ 727,836
Segmented assets	$ 2,119,241	$ 1,847,745	$ 2,605,535	$ 149,964	-	$ 6,722,485

Supplementary Quarterly Financial Information
(unaudited)

FINANCIAL HIGHLIGHTS[1]

($ millions unless otherwise indicated)	**Q3-14**	Q2-14	Q1-14	Q4-13	Q3-13
Net Revenue[2]					
Gas	**$ 102.6**	$ 102.6	$ 122.0	$ 100.6	$ 89.0
Power	**43.0**	32.6	36.2	47.9	53.9
Utilities	**72.5**	83.2	148.9	123.1	104.2
Corporate	**1.3**	3.1	(7.8)	(4.8)	0.2
Intersegment Elimination	**(2.0)**	(1.5)	(2.7)	(2.2)	(0.7)
	$ 217.4	$ 219.9	$ 296.5	$ 264.6	$ 246.6
EBITDA[2]					
Gas	**$ 55.8**	$ 57.1	$ 76.5	$ 55.4	$ 44.1
Power	**30.7**	21.6	23.6	36.8	44.8
Utilities	**23.6**	35.8	97.1	70.8	59.0
Corporate	**(6.3)**	(7.3)	(9.0)	(13.8)	(8.1)
	$ 103.8	$ 107.2	$ 188.2	$ 149.2	$ 139.8
Operating Income (Loss)[2]					
Gas	**$ 38.3**	$ 39.5	$ 20.3	$ 37.7	$ 8.9
Power	**19.3**	13.0	5.0	26.2	37.6
Utilities	**7.8**	19.9	81.2	55.4	42.0
Corporate	**(7.1)**	(8.0)	(9.7)	(14.6)	(7.6)
	$ 58.3	$ 64.4	$ 96.8	$ 104.7	$ 80.9
Normalized Operating Income (Loss)[2]					
Gas	**$ 39.0**	$ 40.0	$ 47.5	$ 38.8	$ 26.3
Power	**19.4**	13.2	15.9	29.6	37.6
Utilities	**7.8**	19.9	81.2	55.4	7.5
Corporate	**(6.9)**	(8.6)	(7.6)	(11.9)	(7.9)
	$ 59.3	$ 64.5	$ 137.0	$ 111.9	$ 63.5

(1) Columns may not add due to rounding.

(2) Non-GAAP financial measure.

Supplementary Quarterly Operating Information

(unaudited)

	Q3-14	Q2-14	Q1-14	Q4-13	Q3-13
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	**1,447**	1,476	1,573	1,454	1,244
Extraction volumes (Bbls/d)(1) (2)	**72,969**	69,867	72,015	68,765	63,592
Frac spread - realized ($/Bbl)(1) (3)	**18.43**	22.12	30.38	25.04	24.63
Frac spread - average spot price ($/Bbl)(1)(4)	**20.82**	22.95	40.30	32.38	28.64
POWER					
Volume of power sold (GWh)(1)	**1,464**	1,067	1,181	1,327	1,256
Average price realized on sale of power ($/MWh)(1) (5)	**74.51**	55.92	69.36	65.22	79.42
Alberta Power Pool average spot price ($/MWh)(1)	**64.34**	42.43	60.60	48.59	83.61
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	**3.1**	6.2	12.8	10.8	2.7
Natural gas deliveries - transportation (PJ)(6)	**1.0**	1.2	1.9	1.5	1.2
U.S. utilities					
Natural gas deliveries end use (Bcf) (6)	**6.1**	10.6	32.5	23.9	5.8
Natural gas deliveries transportation (Bcf) (6)	**8.5**	8.4	12.4	10.9	8.0
Service sites(7)	**554,837**	553,320	557,062	555,198	548,013
Degree day variance from normal - AUI (%)(8)	**(6.2)**	10.8	5.5	11.2	(39.1)
Degree day variance from normal - Heritage Gas (%)(8)	**(1.5)**	3.7	3.9	9.4	(8.0)
Degree day variance from normal - SEMCO Gas (%)(9)	**44.7**	9.9	24.1	11.3	26.4
Degree day variance from normal - ENSTAR (%)(9)	**(8.3)**	(7.7)	(8.3)	(1.3)	(6.4)

(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, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.

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

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

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

(8) A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

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

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
kV	kilovolt
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
mtpa	metric tonnes per annum
MW	megawatt
MWh	megawatt-hour
PJ	petajoule
MMBTU	million British thermal unit

ABOUT ALTAGAS

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

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