AltaGas

NEWS RELEASE
ALTAGAS REPORTS STRONG SECOND QUARTER RESULTS AND INCREASES DIVIDEND

Calgary, Alberta (August 1, 2013) – AltaGas Ltd. (AltaGas) (TSX:ALA) (TSX:ALA.PR.A) (TSX:ALA.PR.U) today reported a 150 percent increase in normalized net income per share. Normalized net income applicable to common shares was $35.5 million ($0.30 per share) for the three months ended June 30, 2013, compared to $10.4 million ($0.12 per share) for the same period 2012. Net income applicable to common shares reported was $35.9 million ($0.31 per share) for the three months ended June 30, 2013, compared to $25.8 million ($0.29 per share) for the same period 2012.

Stronger earnings also resulted in stronger cash flows. Normalized EBITDA more than doubled to $106.2 million for second quarter 2013 compared to $51.7 million in second quarter 2012. Normalized funds from operations increased to $83.1 million ($0.71 per share) for second quarter 2013 compared to $40.7 million ($0.45 per share) for second quarter 2012.

"We are pleased to report another very solid quarter with substantial growth in earnings and cash flow," said David Cornhill, Chairman and CEO of AltaGas. "We had strong performance from all our businesses and we have attractive growth opportunities. Therefore, we are pleased to announce our Board approved a dividend increase of a quarter cent per share per month. In addition to the increase approved last quarter, this results in a $0.09 cent or 6.25 percent increase to our dividend on an annualized basis. On a full year basis the dividend is now $1.53 per share. The Board and management remain committed to enhancing returns for our shareholders."

Normalized net income for the six months ended June 30, 2013 increased to $91.1 million, an 80 percent increase over the same period 2012. Normalized net income per share increased 46 percent to $0.82 per share, up from $0.56 per share.

For the six months ended June 30, 2013, normalized EBITDA increased 76 percent to $252.1 million compared to $143.1 million for the same period 2012. Normalized funds from operations for the six months ended June 30, 2013, increased 78 percent to $205.5 million ($1.84 per share) compared to $115.5 million ($1.29 per share) for the same period 2012.

Operating income from the business segments increased 89 percent in the second quarter 2013 compared to the same quarter 2012, primarily driven by the addition of the U.S. utilities in August 2012, higher throughput in the Gas business, higher power prices realized and the addition of the new Blythe power facility in mid-May 2013. Earnings were partially offset by lower frac spreads and higher operating costs in the quarter.

AltaGas also announced today that its wholly owned subsidiary Pacific Northern Gas Ltd. (PNG) has entered into Transportation Reservation Agreements with both Douglas Channel Gas Services Ltd. and AltaGas Idemitsu Joint Venture Limited Partnership for 520 Mmcf/d of natural gas transportation capacity on the proposed PNG pipeline expansion. The PNG expansion is expected to increase capacity of the PNG system to approximately 750 Mmcf/d from its current capacity of 115 Mmcf/d. PNG continues to work with other potential shippers for the remaining capacity.

"Securing shippers for the expansion of our PNG pipeline has been a critical milestone toward executing on our LNG export plans," said Mr. Cornhill. "We are pleased with our progress and continue to work with other shippers to secure the remaining capacity on the pipeline expansion. We continue to lead the way in getting Canadian natural gas to export markets."

AltaGas also announced today the expansion of its Cogeneration fleet at Harmattan to 45 MW. AltaGas will construct the new 15 MW Cogeneration facility to meet the increased power demand at the Harmattan complex and increase sales to the Alberta power market. Cogen III is expected to be in service in the fourth quarter 2014 with a total project cost estimated at $40 million.

AltaGas is also expanding its Cold Lake natural gas transmission system to deliver natural gas to provide steam to two heavy oil projects near Cold Lake, Alberta. The estimated cost of both projects is $17 million and both are underpinned by long-term take-or-pay transportation agreements. The expansion is expected to be in service in late 2014.

AltaGas continues to make good progress on the Northwest run-of-river projects, which include the Forrest Kerr, McLymont Creek and Volcano Creek generation facilities. The projects remain ahead of schedule and on budget. The powerhouse activities continue as planned and the power tunnel inlet gate control structure and intake desander structure was completed in the quarter. Three turbine units are on-site with installation expected to begin by mid-August. The installation of the penstock and turbines are expected to be completed in third quarter 2013. The project is expected to be mechanically complete by the end of 2013, with commissioning to follow based on the availability of the Northwest Transmission Line (NTL). In-service date is on target for mid-2014.

Construction continues to progress on both the 66 MW McLymont Creek project and 16 MW Volcano Creek project. The McLymont Creek engineering design is now 95 percent complete. Construction of the 7-kilometre McLymont intake access road is on-going and the pioneer trail is 55 percent completed and anticipated to be completed within the next 90 days. Excavation of the McLymont power portal has been completed and approximately 15 percent of the 2,800-metre power tunnel has been excavated. Excavation of the Volcano Creek intake site and diversion have been completed and the installation of the weir embeds has commenced. At Volcano Creek 100 percent of the penstock right-of-way has been cleared and excavation of the penstock trench has commenced. The powerhouse foundation is approximately 80 percent complete and excavation of the headrace is complete. The two projects are expected to be in service in mid-2015.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- The Board approved a dividend of $0.1275 per common share for the August 2013 dividend. The dividend will be paid on September 16, 2013, to common shareholders of record on August 26, 2013. The ex-dividend date is August 22, 2013. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board approved a dividend of $0.3125 per share for the period commencing July 1, 2013, and ending September 30, 2013, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on September 30, 2013 to shareholders of record on September 16, 2013. The ex-dividend date is September 12, 2013; and
- The Board also approved a dividend of US$0.275 per share for the period commencing July 1, 2013, and ending September 30, 2013, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on September 30, 2013, to shareholders of record on September 16, 2013. The ex-dividend date is September 12, 2013.

CONFERENCE CALL AND WEBCAST DETAILS:

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

Members of the media, investment communities and other interested parties may dial (416) 340-8410 or call toll free at 1-866-225-2055. There is no passcode. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_events. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905) 694-9451 or 1-800-408-3053. The passcode is 6668430. The replay expires at midnight (Eastern) on August 8, 2013.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and unaudited condensed interim Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the three and six months ended June 30, 2013, compared to the three and six months ended June 30, 2012. This MD&A dated August 1, 2013, 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 six months ended June 30, 2013, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2012.

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, Information Circular, and Proxy Statement, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., SEMCO Energy Inc. (SEMCO) and AltaGas Power Holdings (U.S.) Inc., (collectively, the operating subsidiaries).

SECOND QUARTER HIGHLIGHTS (1)

- Normalized net income per share increased 150 percent to $0.30 compared to $0.12 in second quarter 2012;
- Normalized funds from operations per share increased 58 percent to $0.71 compared to $0.45 in second quarter 2012;
- Normalized EBITDA increased 105 percent to $106.2 million compared to $51.7 million in second quarter 2012;
- Normalized operating income increased 124 percent to $68.0 million compared to $30.4 million in second quarter 2012;
- Net debt was $2,936.2 million as at June 30, 2013, compared to $1,494.2 million as at June 30, 2012 and $2,690.5 million as at December 31, 2012;
- Debt-to-total capitalization ratio was 54.2 percent as at June 30, 2013, compared to 48.4 percent as at June 30, 2012 and 57.4 percent as at December 31, 2012;
- Acquired a 507 MW natural gas-fired combined cycle plant (Blythe Energy Center) for US$515 million. The facility is fully contracted under a Power Purchase Arrangement (PPA) with Southern California Edison (SCE);
- Closed a public offering of 11,615,000 common shares on April 4, 2013 for aggregate gross proceeds of approximately $405 million;
- Issued US$175 million of senior unsecured medium-term notes (MTN) on April 13, 2013. The notes carry a floating rate coupon of three-month LIBOR plus 0.79 percent and mature on April 12, 2015; and
- Issued $300 million of senior unsecured MTNs on June 11, 2013. The notes carry a coupon rate of 3.57 percent and mature on June 12, 2023.

(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 June 30 **2013**	2012	Six months ended June 30 **2013**	2012
Revenue	**458.6**	272.2	**1,072.1**	633.8
Net revenue(1)	**211.8**	144.0	**449.1**	310.4
Normalized operating income(1)	**68.0**	30.4	**177.2**	99.7
Normalized EBITDA(1)	**106.2**	51.7	**252.1**	143.1
Net income applicable to common shares	**35.9**	25.8	**85.0**	67.1
Normalized net income(1)	**35.5**	10.4	**91.1**	50.6
Total assets	**6,704.3**	3,852.1	**6,704.3**	3,852.1
Total long-term liabilities	**3,598.9**	1,901.1	**3,598.9**	1,901.1
Net additions to property, plant and equipment	**715.8**	176.4	**835.5**	323.8
Dividends declared(2)	**43.8**	31.1	**81.8**	62.0
Cash flows				
Normalized funds from operations(1)	**83.1**	40.7	**205.5**	115.5

($ per share, except shares outstanding)	Three months ended June 30 **2013**	2012	Six months ended June 30 **2013**	2012
Normalized EBITDA(1)	**0.90**	0.57	**2.26**	1.59
Net income - basic	**0.31**	0.29	**0.76**	0.75
Net income - diluted	**0.30**	0.28	**0.74**	0.74
Normalized net income(1)	**0.30**	0.12	**0.82**	0.56
Dividends declared(2)	**0.37**	0.345	**0.73**	0.69
Cash flows				
Normalized funds from operations(1)	**0.71**	0.45	**1.84**	1.29
Shares outstanding - basic (millions)				
During the period(3)	**117.7**	90.0	**111.7**	89.8
End of period	**118.4**	90.3	**118.4**	90.3

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

(2) Dividends declared of $0.12 per common share per month commencing September 10, 2012 and $0.125 commencing May 2013.

(3) Weighted average.

Three Months Ended June 30

Normalized net income for second quarter 2013 was $35.5 million ($0.30 per share), an increase of 241 percent compared to $10.4 million ($0.12 per share) reported in second quarter 2012. The increase was primarily due to higher natural gas volumes processed, higher realized power prices, colder temperatures in Alberta and Nova Scotia, lower general and administrative costs, and an adjustment to the deferred tax liability. Second quarter results included the impact from growth across all business segments and all contributed positive earnings in the quarter. These increases were partially offset by lower frac spreads, higher operating costs, a one-time settlement of a customer dispute recorded in second quarter 2012 and higher interest expense.

Net income applicable to common shares for second quarter 2013 was $35.9 million ($0.31 per share) compared to $25.8 million ($0.29 per share) in second quarter 2012.

Net income applicable to common shares for second quarter 2013 is normalized for a statutory tax rate change related to taxes on dividends paid on preferred shares in prior years of $2.4 million, unrealized loss on risk management contracts of $1.2 million, after-tax transaction costs of $0.5 million related to an acquisition, the write-off of a power asset of $0.4 million and unrealized gains on held-for-trading assets of $0.1 million.

Stronger earnings in the quarter also resulted in strong growth in cash flow in the quarter compared to second quarter 2012. Normalized funds from operations for second quarter 2013 increased 104 percent to $83.1 million ($0.71 per share), compared to $40.7 million ($0.45 per share) in same quarter 2012. Normalized EBITDA for second quarter 2013 was $106.2 million, a 105 percent increase, compared to $51.7 million in same quarter 2012.

Normalized operating income for second quarter 2013 was 124 percent higher at $68.0 million compared to $30.4 million in same quarter 2012. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest and income taxes.

Operating and administrative expense for second quarter 2013 was $107.9 million, compared to $69.7 million in same quarter 2012. The increases were primarily due to growth in assets and higher power costs at gas processing facilities. Amortization expense for second quarter 2013 was $37.8 million compared to $20.5 million in same quarter 2012. Accretion expense for second quarter 2013 was $0.9 million compared to $0.8 million in same quarter 2012.

Interest expense for second quarter 2013 was $25.2 million compared to $13.1 million in same quarter 2012. Interest expense increased due to a higher average debt balance of $2,808.7 million in second quarter 2013 compared to $1,578.9 million in same quarter 2012 and lower capitalized interest of $6.9 million in second quarter 2013 (second quarter 2012 - $8.3 million). The higher debt was a result of growth of the Corporation. The increase in interest expense was partially offset by a lower average borrowing rate of 4.6 percent in second quarter 2013 (second quarter 2012 - 5.4 percent).

AltaGas recorded an income tax recovery of $2.9 million for second quarter 2013 compared to income tax expense of $8.7 million in same quarter 2012. Income tax expense increased as a result of higher earnings but was more than offset by an adjustment to the 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 the dividends paid on preferred shares in the current and prior years.

Six Months Ended June 30

Normalized net income for first half 2013 was $91.1 million ($0.82 per share), an increase of 80 percent compared to $50.6 million ($0.56 per share) reported for same period 2012. The increase was primarily due to higher natural gas volumes processed, higher realized power prices, colder weather in Alberta and Nova Scotia, lower general and administrative expenses, and an adjustment to the deferred tax liability. First half 2013 results included the impact from growth across all business segments and all contributed positive earnings in the period. These increases were partially offset by lower contribution from the sale of NGL, higher operating costs, a one-time settlement of a customer dispute recorded in second quarter 2012 and higher interest expense.

Net income applicable to common shares for first half 2013 was $85.0 million ($0.76 per share) compared to $67.1 million ($0.75 per share) for same period 2012.

Net income applicable to common shares for first half 2013 is normalized for after-tax transaction costs related to acquisitions, unrealized losses on held-for-trading assets and unrealized losses on risk management contracts, the write-off of a power asset and the statutory tax rate change related to taxes on dividends paid on preferred shares in prior years.

Stronger earnings also resulted in stronger cash flow. Normalized funds from operations for first half 2013 increased 78 percent to $205.5 million ($1.84 per share), compared to $115.5 million ($1.29 per share) for same period 2012. Normalized EBITDA for first half 2013 was $252.1 million, a 76 percent increase, compared to $143.1 million for same period 2012.

Normalized operating income for first half 2013 was 78 percent higher at $177.2 million compared to $99.7 million for same period 2012. Normalized operating results were driven by the same factors as described above related to normalized net income except for the impact of interest and income taxes.

Operating and administrative expense for first half 2013 was $207.8 million, compared to $143.3 million for same period 2012. The increases were primarily due to growth in assets and higher power costs at gas processing facilities. Amortization expense for first half 2013 was $73.5 million compared to $41.8 million for same period 2012. Accretion expense for first half 2013 was $1.9 million compared to $1.6 million for same period 2012.

Interest expense for first half 2013 was $49.8 million compared to $25.8 million for same period 2012. Interest expense increased due to a higher average debt balance of $2,746.9 million in first half 2013 compared to $1,491.1 million in same period 2012 and lower capitalized interest of $13.2 million in first half 2013 (first half 2012 - $14.9 million). The higher debt was a result of growth of the Corporation. The increase in interest expense was partially offset by a lower average borrowing rate of 4.6 percent in first half 2013 (first half 2012 - 5.5 percent).

AltaGas recorded income tax expense of $18.1 million for first half 2013 compared to $22.4 million for same period 2012. Income tax expense increased as a result of higher earnings but was more than offset by an adjustment to the deferred income 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 the dividends paid on preferred shares in the current and prior years.

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger earnings in 2013 compared to 2012 due to growth in natural gas volumes processed, power generated and natural gas distributed to customers at the utilities. New and expanded assets added recently include the Blythe Energy, LLC (Blythe) acquisition in May 2013, the Gordondale and Co-stream gas processing facilities commissioned in December 2012, the Busch Ranch wind farm (Busch Ranch) added in October 2012, the SEMCO acquisition and the Blair Creek expansion added in August 2012, the Gilby Gas Plant acquired in July 2012, the gas fired power assets commissioned in June 2012, and the biomass assets acquired in January 2012. Earnings may however be negatively impacted if frac spreads and power prices in Alberta are lower in 2013 compared to 2012 and volumes processed do not increase as expected.

For full year 2013, earnings and throughput in the Gas segment are expected to be higher than 2012. Volumes processed are expected to be higher as a result of the new and expanded assets added in the second half of 2012. These new assets are primarily underpinned by long-term take-or-pay commitments from customers resulting in no incremental direct exposure to commodity prices from these new revenue streams.

In second half 2013, AltaGas expects to report stronger earnings from the Gas segment than first half 2013. The stronger results in second half 2013 are expected to result from higher volumes processed at the Gordondale and Blair Creek facilities as drilling activity continues to increase in their catchment areas and volumes ramp up further. During second quarter 2013, the Co-stream facility operated below capacity primarily as a result of reduced inlet compression off the Nova Gas Transmission Ltd. (NGTL) system and compressor motor repairs required. AltaGas expects to report the full cost-of-service revenue requirement beginning in mid-August. Inlet pressure issues continue but AltaGas is addressing the matter with NOVA Chemicals Corporation and TransCanada Pipelines Limited to resolve. Volumes at the Younger facility are also expected to increase as a result of increased producer activity in the area.

Management estimates an average of approximately 6,200 Bbls/d will be exposed to frac spread for the remainder of 2013. For second half 2013, 5,000 Bbls/d have been hedged at an average price of approximately $30/Bbl prior to deducting extraction premiums.

In the Power segment, AltaGas expects to report stronger earnings as a result of the addition of new assets including Blythe Energy Center, the second cogeneration facility (Cogeneration II) at Harmattan which began commercial operation in June 2012 and Busch Ranch which began operating in October 2012. The Blythe acquisition closed on May 16, 2013 and is expected to report approximately $50 million EBITDA on an annualized basis.

AltaGas has hedged approximately 59 percent and 44 percent of volumes exposed to Alberta power prices for third and fourth quarter 2013, respectively, all at an average price of approximately $66/MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to the medium and long-term power prices as reflected in the current forward curves.

Results in 2013 for the Utilities segment are expected to be stronger than 2012, driven mainly by the acquisition of SEMCO. In 2013 SEMCO is expected to generate approximately $130 million of EBITDA on a weather normalized basis. The Canadian utilities are expected to report increased earnings in 2013 based on forecasted rate base growth of approximately nine percent. AltaGas expects significant seasonality in 2013 results as SEMCO contributes its first full year of earnings. Utilities earn most of their income in the first and fourth quarters in the heating seasons with the third quarter being the weakest quarter.

On February 15, 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 liquefied natural gas (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. The amendment is subject to British Columbia Utilities Commission (BCUC) regulatory approval, which is expected in third quarter 2013.

GROWTH CAPITAL

Based on projects currently under review, development or construction, and the acquisition of Blythe completed in second quarter 2013, AltaGas expects capital expenditures for 2013 to be $1.0 to $1.1 billion. The Corporation is also focused on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through growing, internally-generated cash flow, the dividend reinvestment plan and available bank lines. As at June 30, 2013, the Corporation had approximately $873 million available in its credit facilities.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwest British Columbia: Forrest Kerr, McLymont Creek and Volcano Creek. All three projects are currently in various phases of construction. The 277 MW Northwest Projects are contracted with 60-year fully inflation indexed Energy Purchase Arrangements (EPA) with BC Hydro, as well as Impact Benefit Agreements with the Tahltan First Nation.

<u>Forrest Kerr Project</u>

Construction of the 195 MW Forrest Kerr run-of-river project (Forrest Kerr Project) continues to progress well and remains ahead of schedule and on budget. The powerhouse activities continue as planned and the power tunnel inlet gate control structure and intake desander structure was completed in the quarter. Three turbine units are on-site with installation expected to begin by mid-August. The installation of the penstock and turbines are expected to be completed in third quarter 2013. The project is expected to be mechanically complete by the end of 2013, with commissioning to follow based on the availability of the Northwest Transmission Line (NTL). In-service date is on target for mid-2014.

<u>McLymont Creek and Volcano Creek Projects</u>

Construction has commenced on both the 66 MW McLymont Creek run-of-river project (McLymont Creek Project) and 16 MW Volcano Creek run-of-river project (Volcano Creek Project). Construction of the 7-kilometre McLymont intake access road is on-going and the pioneer trail is 55 percent completed and anticipated to be completed within the next 90 days. Excavation of the McLymont power portal has been completed and approximately 15 percent of the 2,800-metre power tunnel has been excavated. Excavation of the Volcano Creek intake site and diversion have been completed and the installation of the weir embeds has commenced. At Volcano Creek the excavation of the penstock trench has commenced, 100 percent of the penstock right-of-way has been cleared, the powerhouse foundation is approximately 80 percent complete and excavation of the headrace is complete. The two projects are expected to be in service in mid-2015.

AltaGas Idemitsu Joint Venture Limited Partnership

On January 28, 2013, AltaGas signed an agreement with Idemitsu Kosan Co., Ltd. (Idemitsu) to form the AltaGas Idemitsu Joint Venture Limited Partnership (AltaGas Idemitsu LP). AltaGas and Idemitsu each own a 50 percent interest in AltaGas Idemitsu LP. AltaGas Idemitsu LP plans to pursue opportunities to develop long-term natural gas supply and sales arrangements to meet the growing demand for natural gas in Asia. AltaGas Idemitsu LP is also pursuing opportunities to develop a liquefied petroleum gas (LPG or propane) export business, including logistics, plant refrigeration and storage facilities.

LNG Export Business

AltaGas Idemitsu LP is currently developing the proposed project feasibility study which is expected to be completed in 2014. AltaGas Idemitsu LP is also preparing preliminary engineering designs for the construction of the liquefaction facilities and has begun identification of potential site locations. AltaGas Idemitsu LP is currently in discussions with market participants to develop sales agreements. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LNG exports could begin as early as 2017.

On July 18, 2013, a wholly owned subsidiary of AltaGas Idemitsu LP, signed a 20-year Transportation Reservation Agreement (TRA) with PNG for 325 Mmcf/day of natural gas transportation capacity related to the PNG expansion. The TRA commits AltaGas Idemitsu LP to backstop development costs related to the expansion of the pipeline.

LPG Export Business

AltaGas Idemitsu LP is currently developing the proposed project feasibility study which is expected to be completed in 2014. Preliminary engineering designs for the construction of the LPG facilities have begun along with identification of potential site locations. AltaGas Idemitsu LP is currently in discussions with market participants to develop sales and logistics agreements. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LPG export business could begin as early as 2016.

Pacific Northern Gas Ltd. Expansion

PNG continues to proceed with the development of potential expansion capacity of approximately 600 Mmcf/d on its transmission line. During second quarter 2013, PNG commenced negotiations with potential shippers for the commercial support required to develop the expansion capacity, initiated engagement with First Nations and is entering the environmental review process. On July 18, 2013 two parties signed TRAs to support the PNG expansion project. The TRAs provide for cost recovery of development costs related to the expansion. On July 24, 2013, the British Columbia Environmental Assessment Office issued an order accepting PNG's expansion project into the environmental assessment process following PNG's filing of its project description. PNG expects to continue to further advance the expansion project through the environmental assessment process, during third quarter 2013.

Cold Lake System Expansion

AltaGas is expanding its Cold Lake natural gas transmission system to deliver natural gas to provide steam to two heavy oil projects near Cold Lake, Alberta. The estimated cost of both projects is $17 million and both are underpinned by long-term take-or-pay transportation agreements. The expansion is expected to be in service in late 2014.

Cogeneration III

AltaGas is expanding its Cogeneration fleet at Harmattan to 45 MW. AltaGas will construct the new 15 MW Cogeneration facility (Cogeneration III) to meet the increased power demand at the Harmattan complex and increase sales to the Alberta power market. Cogeneration III is expected to be in service in fourth quarter 2014 with a total project cost estimated at $40 million.

NON-GAAP FINANCIAL MEASURES

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

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

Net Revenue	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Net revenue	**$ 211.8**	$ 144.0	**$ 449.1**	$ 310.4
Add (deduct):				
Other (income) expense	**(0.9)**	1.3	**(0.3)**	(0.5)
(Income) loss from equity investments	**(49.5)**	0.1	**(66.2)**	(12.1)
Cost of sales	**297.2**	126.8	**689.5**	336.0
Revenue (GAAP financial measure)	**$ 458.6**	$ 272.2	**$ 1,072.1**	$ 633.8

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

Normalized Operating Income	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Normalized operating income	**$ 68.0**	$ 30.4	**$ 177.2**	$ 99.7
Add (deduct):				
Transaction costs related to acquisitions	**(0.8)**	0.4	**(1.3)**	(1.2)
Unrealized gain (loss) on held-for-trading	**0.1**	(1.4)	**(0.9)**	0.3
Write-off of assets	**(0.5)**	-	**(0.5)**	-
Operating income	**66.8**	29.4	**174.5**	98.8
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**(1.6)**	23.6	**(8.7)**	24.8
Interest expense	**(25.2)**	(13.1)	**(49.8)**	(25.8)
Foreign exchange loss	**(0.4)**	(2.0)	**-**	(2.1)
Income tax (expense) recovery	**2.9**	(8.7)	**(18.1)**	(22.4)
Net income applicable to non-controlling interests	**(1.8)**	(0.3)	**(3.4)**	(0.6)
Preferred share dividends	**(4.8)**	(3.1)	**(9.5)**	(5.6)
Net income applicable to common shares (GAAP financial measure)	**$ 35.9**	$ 25.8	**$ 85.0**	$ 67.1

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 gains or losses on risk management contracts, interest expense, foreign exchange 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 gains (losses) on held-for-trading and write-off of assets.

Normalized EBITDA	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Normalized EBITDA	**$ 106.2**	$ 51.7	**$ 252.1**	$ 143.1
Add (deduct):				
Transaction costs related to acquisitions	**(0.8)**	0.4	**(1.3)**	(1.2)
Unrealized gain (loss) on held-for-trading	**0.1**	(1.4)	**(0.9)**	0.3
EBITDA	**105.5**	50.7	**249.9**	142.2
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**(1.6)**	23.6	**(8.7)**	24.8
Depreciation, depletion and amortization	**(37.8)**	(20.5)	**(73.5)**	(41.8)
Accretion of asset retirement obligations	**(0.9)**	(0.8)	**(1.9)**	(1.6)
Interest expense	**(25.2)**	(13.1)	**(49.8)**	(25.8)
Foreign exchange loss	**(0.4)**	(2.0)	**-**	(2.1)
Income tax (expense) recovery	**2.9**	(8.7)	**(18.1)**	(22.4)
Net income applicable to non-controlling interests	**(1.8)**	(0.3)	**(3.4)**	(0.6)
Preferred share dividends	**(4.8)**	(3.1)	**(9.5)**	(5.6)
Net income applicable to common shares (GAAP financial measure)	**$ 35.9**	$ 25.8	**$ 85.0**	$ 67.1

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, accretion of asset retirement obligations, interest expense, foreign exchange loss, income tax expense (recovery), 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 and unrealized gains (losses) on held-for-trading.

Normalized Net Income	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Normalized net income	**$ 35.5**	$ 10.4	**$ 91.1**	$ 50.6
Add (deduct):				
Unrealized after-tax gain (loss) on risk management contracts	**(1.2)**	17.7	**(6.5)**	18.5
Unrealized after-tax gain (loss) on held-for-trading assets	**0.1**	(1.2)	**(0.8)**	0.3
After-tax transaction costs and foreign exchange loss related to acquisitions	**(0.5)**	(1.1)	**(0.8)**	(2.3)
Write-off of assets	**(0.4)**	-	**(0.4)**	-
Statutory tax rate change	**2.4**	-	**2.4**	-
Net income applicable to common shares (GAAP financial measure)	**$ 35.9**	$ 25.8	**$ 85.0**	$ 67.1

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 including foreign exchange gains or losses, gains or losses on sale of assets on an after-tax basis, statutory tax rate change and write-off of assets.

Normalized Funds from Operations	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Normalized funds from operations	**$ 83.1**	$ 40.7	**$ 205.5**	$ 115.5
Add (deduct):				
Transaction costs and foreign exchange loss related to acquisitions	**(0.8)**	(1.4)	**(1.3)**	(3.1)
Funds from operations	**82.3**	39.3	**204.2**	112.4
Add (deduct):				
Net change in operating assets and liabilities	**57.5**	0.7	**38.7**	26.8
Asset retirement obligations settled	**(0.2)**	(0.1)	**(0.7)**	(0.5)
Cash from operations (GAAP financial measure)	**$ 139.6**	$ 39.9	**$ 242.2**	$ 138.7

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. 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, expenditures incurred to settle asset retirement obligations and non-operating related expenses.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income ($ millions)	Three months ended June 30 **2013**	2012	Six months ended June 30 **2013**	2012
Gas	**$ 20.3**	$ 19.5	**$ 48.1**	$ 49.6
Power	**31.6**	14.0	**53.6**	40.9
Utilities	**21.4**	5.2	**86.9**	24.7
Sub-total: Operating Segments	**73.3**	38.7	**188.6**	115.2
Corporate[1]	**(6.5)**	(9.3)	**(14.1)**	(16.4)
	$ 66.8	$ 29.4	**$ 174.5**	$ 98.8

(1) *Includes mark-to-market gain/loss on held-for-trading assets and excludes mark-to-market gain/loss on risk management contracts.*

GAS

OPERATING STATISTICS	Three months ended June 30 **2013**	2012	Six months ended June 30 **2013**	2012
Extraction and Transmission (E&T)				
Extraction inlet gas processed (net Mmcf/d)[1]	**953**	829	**965**	896
Extraction ethane volumes (Bbls/d)[1]	**31,225**	20,844	**31,280**	25,104
Extraction NGL volumes (Bbls/d)[1]	**19,740**	13,703	**16,511**	14,980
Total extraction volumes (Bbls/d)[1]	**50,965**	34,547	**47,791**	40,084
Frac spread - realized ($/Bbl)[1] [2]	**20.80**	27.64	**25.13**	31.17
Frac spread - average spot price ($/Bbl)[1] [3]	**17.85**	26.85	**22.48**	34.26
Field Gathering and Processing (FG&P)				
Processing throughput (gross Mmcf/d)[1]	**413**	351	**408**	375
Energy Services				
Average volumes transacted (GJ/d)[1][4]	**328,777**	318,738	**383,754**	347,450

(1) *Average for the period.*

(2) *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 shrinkage gas and extraction premiums, divided by the total frac exposed volumes produced during the period.*

(3) *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 shrinkage gas and extraction premiums, divided by the respective frac exposed volumes for the period.*

(4) *Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.*

In second quarter 2013, average ethane volumes increased by 10,381 Bbls/d and NGL volumes increased by 6,037 Bbls/d, compared to same quarter 2012. During first half 2013, average ethane volumes increased by 6,176 Bbls/d and NGL volumes increased by 1,531 Bbls/d, compared to same period 2012. The volume increases were due to the addition of the Co-stream facility at Harmattan, partially offset by lower volumes at the Younger facility and Joffre Ethane Extraction Plant. Volumes in second quarter 2012 were lower due to outages downstream of the AltaGas facilities. During second quarter 2013, the Co-stream facility operated below capacity primarily as a result of reduced inlet compression off the NGTL system and compressor motor repairs required.

FG&P throughput in second quarter 2013 averaged 413 Mmcf/d compared to 351 Mmcf/d in same quarter 2012. FG&P throughput in first half 2013 averaged 408 Mmcf/d compared to 375 Mmcf/d in same period 2012. The increases were primarily driven by the addition of the Gordondale facility, the Blair Creek expansion and the acquisition of the 50 percent interest in the Quatro midstream assets, including its 87 percent interest in the Gilby Gas Plant. In second quarter the Blair Creek facility operated at approximately 73 percent utilization and the Gordondale gas plant operated as designed with utilization of approximately 44 percent and the Gilby facility was at approximately 82 percent of capacity.

Three Months Ended June 30

The Gas segment reported operating income of $20.3 million in second quarter 2013 compared to $19.5 million in same quarter 2012. Operating income increased as a result of higher natural gas volumes processed, partially offset by lower frac spreads, higher operating costs and a one-time settlement of a customer dispute recorded in second quarter 2012. At the Co-stream facility, compressor motor repairs resulted in lower capacity thereby resulting in lower revenues.

During second quarter 2013, AltaGas hedged approximately 57 percent of frac exposed production at an average price of $34/Bbl. During second quarter 2012, AltaGas hedged approximately 80 percent of frac exposed production at an average price of $35/Bbl. The average indicative spot NGL frac spread for second quarter 2013 was approximately $18/Bbl compared to approximately $27/Bbl in same quarter 2012.

Six Months Ended June 30

The Gas segment reported operating income of $48.1 million in first half 2013 compared to $49.6 million in same period 2012. Excluding the impact of a one-time settlement of a customer dispute recorded in second quarter 2012, operating income increased as a result of higher natural gas volumes processed and lower administrative costs, partially offset by lower contribution from the sale of NGL and higher operating costs. At the Co-stream facility, compressor motor repairs resulted in lower capacity thereby resulting in lower revenues.

During first half 2013, AltaGas hedged approximately 58 percent of frac exposed production at an average price of $34/Bbl. During first half 2012, AltaGas hedged approximately 80 percent of frac exposed production at an average price of $35/Bbl. The average indicative spot NGL frac spread for first half 2013 was approximately $22/Bbl compared to approximately $34/Bbl for same period 2012.

POWER

OPERATING STATISTICS	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Volume of power sold (GWh)	**1,035**	802	**1,902**	1,618
Average price realized on the sale of power ($/MWh) (1)	**87.01**	58.54	**80.17**	65.69
Alberta Power Pool average spot price ($/MWh)	**123.41**	40.03	**94.51**	50.08

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

In second quarter 2013, volume of power sold increased by 233 GWh compared to same quarter 2012. Volumes sold in second quarter 2013 comprised of 912 GWh conventional power generation and 123 GWh renewable power generation, compared to 698 GWh conventional power generation and 104 GWh renewable power generation in same quarter 2012. In first half 2013, volume of power sold increased by 284 GWh compared to same period 2012. Volumes sold in first half 2013 comprised of 1,650 GWh conventional power generation and 252 GWh renewable power generation, compared to 1,404 GWh conventional power generation and 214 GWh renewable power generation in same period 2012. The increase in power generated was primarily due to the Blythe acquisition and the addition of new power generation assets in 2012, partially offset by planned and unplanned outages at Sundance.

Three Months Ended June 30

The Power segment reported operating income of $31.6 million in second quarter 2013 compared to $14.0 million in same quarter 2012. Operating income increased primarily as a result of higher realized power prices and the Blythe acquisition. Results in the quarter included transaction costs of $0.8 million related to the Blythe acquisition, as well as $0.5 million related to the write-off of a gas peaking engine. In second quarter 2013, the Alberta power market experienced high power prices and high power price volatility driven by planned and unplanned outages and high demand.

In second quarter 2013, AltaGas was 67 percent hedged in Alberta at an average price of $62/MWh. In second quarter 2012, AltaGas was 74 percent hedged at an average price of $65/MWh.

Six Months Ended June 30

The Power segment reported operating income of $53.6 million in first half 2013 compared to $40.9 million in same period 2012. Operating income increased primarily as a result of higher power prices realized and the Blythe acquisition, partially offset by the impact of lower generation at Bear Mountain and the unplanned outage at Sundance 3 in first quarter 2013. Results for the six months ended June 30, 2013 include transaction costs of approximately $1.3 million related to the Blythe acquisition, as well as $0.5 million related to the write-off of a gas peaking engine.

In first half 2013, AltaGas was 64 percent hedged in Alberta at an average price of $65/MWh. In same period 2012, AltaGas was 74 percent hedged at an average price of $72/MWh.

UTILITIES

OPERATING STATISTICS	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Canadian utilities				
Natural gas deliveries - end-use (PJ)(1)	**5.3**	4.6	**17.0**	15.4
Natural gas deliveries - transportation (PJ)(1)	**1.4**	1.7	**3.0**	3.7
U.S. utilities(2)				
Natural gas deliveries - end-use (Bcf)(1)	**11.6**	-	**40.5**	-
Natural gas deliveries - transportation (Bcf)(1)	**9.8**	-	**22.6**	-
Service sites (3)	**546,906**	115,437	**546,906**	115,437
Degree day variance from normal - AUI (%) (4)	**3.0**	(2.9)	**(3.3)**	(9.3)
Degree day variance from normal - Heritage Gas (%) (4)	**(2.1)**	(9.7)	**(2.1)**	(8.9)
Degree day variance from normal - SEMCO Gas (%) (2) (5)	**16.4**	-	**7.0**	-
Degree day variance from normal - ENSTAR (%) (2) (5)	**12.8**	-	**0.1**	-

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

(2) *Results for U.S. utilities are from August 30, 2012.*

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

(4) *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.*

(5) *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 fifteen years for SEMCO Gas and during the prior ten years for ENSTAR Natural Gas Company (ENSTAR).*

Three Months Ended June 30

The Utilities segment reported operating income of $21.4 million in second quarter 2013 compared to $5.2 million in same quarter 2012. Operating income increased mainly due to the acquisition of SEMCO, which contributed $15.3 million to operating income in the quarter, colder weather at both AUI and Heritage Gas, and rate base growth at the Canadian utilities.

Six Months Ended June 30

The Utilities segment reported operating income of $86.9 million in first half 2013 compared to $24.7 million in same period 2012. Operating income increased mainly due to the acquisition of SEMCO, which contributed $59.8 million, colder weather at both AUI and Heritage Gas, and rate base growth at the Canadian utilities.

CORPORATE

Three Months Ended June 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts in second quarter 2013 was $6.5 million compared to $9.3 million in same quarter 2012. The lower loss was due to an unrealized gain on held-for-trading assets of $0.1 million compared to an unrealized loss of $1.4 million in same quarter 2012, and lower administrative expenses. During second quarter 2012, administrative expenses for Corporate included transaction costs of $0.5 million related to acquisitions.

Six Months Ended June 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts for the six months ended June 30, 2013 was $14.0 million compared to $16.3 million in same period 2012. The lower loss was due to lower administrative expense, partially offset by an unrealized loss on held-for-trading assets of $0.9 million compared to an unrealized gain of $0.3 million in same period 2012. For the six months ended June 30, 2012, administrative expenses for Corporate included transaction costs of $1.8 million related to acquisitions.

INVESTED CAPITAL

During second quarter 2013, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $668.3 million compared to $200.9 million in second quarter 2012. The net invested capital was $667.7 million in second quarter 2013 compared to $200.9 million in same quarter 2012.

Invested Capital - Investment Type

Three months ended **June 30, 2013**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 6.6**	**$ 626.2**	**$ 30.6**	**$ 0.5**	**$ 663.9**
Intangible assets	**0.1**	**-**	**1.4**	**2.9**	**4.4**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
	6.7	**626.2**	**32.0**	**3.4**	**668.3**
Disposals:					
Property, plant and equipment	**(0.6)**	**-**	**-**	**-**	**(0.6)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**$ 6.1**	**$ 626.2**	**$ 32.0**	**$ 3.4**	**$ 667.7**

Invested Capital - Investment Type					Three months ended June 30, 2012
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 110.1	$ 77.6	$ 11.5	$ 0.6	$ 199.8
Intangible assets	0.2	-	0.8	0.1	1.1
Long-term investments and other assets	-	-	-	-	-
	110.3	77.6	12.3	0.7	200.9
Disposals:					
Property, plant and equipment	-	-	-	-	-
Long-term investments and other assets	-	-	-	-	-
Net Invested capital	$ 110.3	$ 77.6	$ 12.3	$ 0.7	$ 200.9

During first half 2013 AltaGas increased property, plant and equipment, intangible assets, long-term investments, and other assets by $774.2 million, compared to $399.2 million in same period 2012. The net invested capital was $773.6 million in first half 2013, compared to $385.4 million in same period 2012.

Invested Capital - Investment Type					**Six months ended June 30, 2013**
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 13.6**	**$ 697.1**	**$ 53.7**	**$ 1.3**	**$ 765.7**
Intangible assets	**3.1**	**-**	**2.0**	**3.4**	**8.5**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
	16.7	**697.1**	**55.7**	**4.7**	**774.2**
Disposals:					
Property, plant and equipment	**(0.6)**	**-**	**-**	**-**	**(0.6)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**$ 16.1**	**$ 697.1**	**$ 55.7**	**$ 4.7**	**$ 773.6**

Invested Capital - Investment Type					Six months ended June 30, 2012
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 194.4	$ 149.5	$ 16.4	$ 0.7	$ 361.0
Intangible assets	1.1	-	1.0	0.1	2.2
Long-term investments and other assets	-	35.9	0.1	-	36.0
	195.5	185.4	17.5	0.8	399.2
Disposals:					
Property, plant and equipment	-	(13.8)	-	-	(13.8)
Long-term investments and other assets	-	-	-	-	-
Net Invested capital	$ 195.5	$ 171.6	$ 17.5	$ 0.8	$ 385.4

AltaGas categorizes its invested capital into maintenance, growth and administration.

Invested Capital - Use — **Three months ended June 30, 2013**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**$ 3.1**	**-**	**-**	**-**	**$ 3.1**
Growth	**3.3**	**626.2**	**32.0**	**2.8**	**664.3**
Administrative	**0.3**	**-**	**-**	**0.6**	**0.9**
Invested capital	**$ 6.7**	**$ 626.2**	**$ 32.0**	**$ 3.4**	**$ 668.3**

Invested Capital - Use — Three months ended June 30, 2012

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	$ 0.9	$ 1.2	-	-	$ 2.1
Growth	108.6	76.4	12.3	0.1	197.4
Administrative	0.8	-	-	0.6	1.4
Invested capital	$ 110.3	$ 77.6	$ 12.3	$ 0.7	$ 200.9

Growth capital expenditures of $664.3 million was reported in second quarter 2013 (second quarter 2012 - $197.4 million). In the Gas segment, growth capital comprised of $1.2 million for construction of Gordondale, $1.2 million for construction of the Co-stream facility and $0.9 million for various other Gas related projects. In the Power segment, growth capital projects included $545.0 million related to the acquisition of Blythe, $67.6 million for the Forrest Kerr Project, $6.4 million for the Volcano Creek Project, $5.9 million for the McLymont Project, $0.9 million for various renewable power development projects in Canada and $0.4 million for the U.S. power assets. The Utilities segment reported growth capital of $14.4 million at the U.S. utilities, $14.6 million at the Canadian utilities and $3.0 million related to the compressed natural gas business at Heritage Gas. The Corporate segment reported an increase in expenditure of $2.8 million.

Maintenance and administrative capital expenditures in second quarter 2013 were $3.1 million and $0.9 million, respectively (second quarter 2012 - $2.1 million and $1.4 million, respectively).

Invested Capital - Use — **Six months ended June 30, 2013**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**$ 6.2**	**-**	**-**	**-**	**$ 6.2**
Growth	**10.1**	**697.1**	**55.7**	**3.8**	**766.7**
Administrative	**0.4**	**-**	**-**	**0.9**	**1.3**
Invested capital	**$ 16.7**	**$ 697.1**	**$ 55.7**	**$ 4.7**	**$ 774.2**

Invested Capital - Use

Six months ended June 30, 2012

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	$ 2.1	$ 1.2	-	-	$ 3.3
Growth	192.2	184.2	17.5	0.1	394.0
Administrative	1.2	-	-	0.7	1.9
Invested capital	$ 195.5	$ 185.4	$ 17.5	$ 0.8	$ 399.2

Growth capital expenditures of $766.7 million was reported in first half 2013 (first half 2012 - $394.0 million). In the Gas segment, growth capital was comprised of $4.9 million for construction of Gordondale, $4.1 million for construction of the Co-stream facility and $1.1 million for various other Gas related projects. In the Power segment, growth capital projects included $545.0 million related to the Blythe acquisition, $130.2 million for the Forrest Kerr Project, $12.1 million for the McLymont Project, $7.7 million for the Volcano Creek Project, $1.5 million for various renewable power development projects in Canada and $0.6 million for the U.S. power assets. The Utilities segment reported growth capital of $29.8 million at the U.S. utilities, $20.0 million at the Canadian utilities and $5.9 million related to the compressed natural gas business at Heritage Gas. The Corporate segment reported an increase in expenditure of $3.8 million.

Maintenance and administrative capital expenditures for first half 2013 were $6.2 million and $1.3 million, respectively (first half 2012 - $3.3 million and $1.9 million, respectively).

RISK MANAGEMENT

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During second quarter 2013, the Corporation had positions in the following types of derivatives, which are also disclosed in the unaudited interim Consolidated Financial Statements:

Commodity Forward Contracts

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

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 $9.02/MWh to $999.99/MWh in second quarter 2013 and $0.00/MWh to $902.99/MWh in second quarter 2012. The average Alberta spot price was $123.41/MWh in second quarter 2013 (second quarter 2012 - $40.03/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 $80.97/MWh in second quarter 2013 (second quarter 2012 - $58.54/MWh). AltaGas has hedged approximately 59 percent and 44 percent of volumes exposed to Alberta power prices for third and fourth quarter 2013, respectively, all at an average price of approximately $66/MWh.

NGL frac spread hedges

The Corporation executes fixed for floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During second quarter 2013, the Corporation had NGL frac spread hedges for an average of 2,000 Bbls/d at an average price of approximately $34/Bbl. 1,000 Bbls/d of propane was also hedged during second quarter 2013. The average indicative spot NGL frac spread for second quarter 2013 was an estimated $17.85/Bbl (second quarter 2012 – $26.85/Bbl). The average NGL frac spread realized by AltaGas in second quarter 2013 was $20.80/Bbl (second quarter 2012 - $27.64/Bbl). For second half 2013, 5,000 Bbls/d have been hedged at an average price of approximately $30/Bbl prior to deducting extraction premiums.

Interest Rate Forward Contracts

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. At June 30, 2013, the Corporation had no interest rate swaps outstanding. At June 30, 2013, the Corporation had fixed the interest rate on 76 percent of its debt (June 30, 2012 - 90 percent).

Foreign Exchange Forward Contracts

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. As at June 30, 2013, Management designated US$590.7 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2012 - $396.5 million).

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.

LIQUIDITY

Cash Flows	Three months ended June 30		Six months ended June 30	
($ millions)	**2013**	2012	**2013**	2012
Cash from operations	**$ 139.6**	$ 39.9	**$ 242.2**	$ 138.7
Investing activities	**(658.5)**	(183.2)	**(768.5)**	(430.3)
Financing activities	**589.6**	144.5	**609.5**	291.1
Effect of exchange rate	**0.3**	-	**0.5**	-
Change in cash	**$ 71.0**	$ 1.2	**$ 83.7**	$ (0.5)

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $139.6 million in second quarter 2013 compared to $39.9 million in second quarter 2012. The increase in cash from operations was primarily due to earnings from new and expanded assets, higher power prices, and higher distributions from equity investments. In addition, operating assets and liabilities increased by $57.5 million compared to an increase of $0.7 million in second quarter 2012 mainly due to seasonality of the new U.S. utilities.

Working Capital

As at June 30 ($ millions except current ratio)	2013	2012
Current assets	**$ 571.0**	$ 292.2
Current liabilities	**623.8**	355.4
Working capital	**(52.8)**	(63.2)
Current ratio	**0.92**	0.82

Working capital was in a deficit position of $52.8 million as at June 30, 2013, compared to a deficit position of $63.2 million as at June 30, 2012. The working capital ratio was 0.92 at the end of second quarter 2013 compared to 0.82 at the end of same quarter 2012. The working capital ratio increased due to an increase in cash, accounts receivable and inventory, partially offset by an increase in accounts payable and current portion of long-term debt.

Investing Activities

Cash used for investing activities in second quarter 2013 was $658.5 million compared to $183.2 million in same quarter 2012. Investing activities in second quarter 2013 primarily comprised of the Blythe acquisition for $536.8 million, $120.5 million related to construction of the Northwest Projects and $1.4 million for intangible assets, compared to investing activities in second quarter 2012 of $181.4 million related to construction activity and $1.0 million for long-term investment acquisitions.

Financing Activities

Cash received from financing activities was $589.6 million in second quarter 2013 compared to $144.5 million in same quarter 2012. Financing activities in second quarter 2013 were primarily comprised of net proceeds from issuance of common shares of $408.8 million and issuance of $933.0 million of long-term debt, partially offset by $469.0 million repayment of long-term debt, and $236.6 million repayment of short-term debt. Financing activities in second quarter 2012 were comprised of $199.4 million of MTNs issuance and $228.0 million of long-term debt repayment. Financing activities in second quarter 2012 also comprised of $199.3 million from issuance of preferred shares. Total dividends paid in second quarter 2013 were $46.5 million, compared to $34.2 million in same quarter 2012.

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 June 30, 2013, AltaGas had total debt outstanding of $3,031.7 million, up from $2,702.3 million at December 31, 2012. As at June 30, 2013, AltaGas had $2,109.0 million in MTNs outstanding, PNG debenture notes of $63.3 million, SEMCO long-term debt of $406.9 million and $621.9 million drawn from bank credit facilities. As at June 30, 2013, AltaGas' current portion of long-term debt was $212.8 million (December 31, 2012 - $9.3 million).

AltaGas' earnings interest coverage for the rolling twelve months ended June 30, 2013 was 2.29 times.

AltaGas' debt-to-total capitalization ratio as at June 30, 2013 was 54.2 percent (December 31, 2012 - 57.4 percent).

		June 30, 2013		December 31, 2012
Debt				
Short-term debt	**$**	**8,086**	$	66,938
Current portion of long-term debt		**212,782**		9,302
Long-term debt		**2,810,842**		2,626,086
Less: cash and cash equivalent		**(95,530)**		(11,827)
Net debt		**2,936,180**		2,690,499
Shareholders' equity		**2,439,179**		1,959,791
Non-controlling interests		**42,516**		40,006
Total capitalization	**$**	**5,417,875**	$	4,690,296
Debt-to-total capitalization ratio (%)		**54.2**		57.4

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The following table summarizes the Corporation's debt covenants for all credit facilities as at June 30, 2013:

Ratios	Debt covenant requirements
Debt-to-capitalization	not greater than 60 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 (Utility Group)	not greater than 67.5 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

As at June 30, 2013, the Corporation had approximately $873 million of available credit facilities and $95.5 million in cash and cash equivalents.

On December 7, 2011, a new $2 billion base shelf prospectus valid for 25 months was filed. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance. As at June 30, 2013, $360.9 million remain available on the base shelf prospectus. AltaGas expects to renew and upsize its base shelf prospectus in the second half of 2013.

On April 13, 2012, AltaGas issued $200 million of senior unsecured MTNs. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020. The net proceeds were used to repay outstanding indebtedness under AltaGas' credit facilities.

On May 25, 2012, PNG's $25 million bank operating facility was amended and extended with a new maturity date of November 22, 2013.

On June 6, 2012, AltaGas issued 8 million five-year rate reset Series C Preferred Shares, at a price of US$25 per Series C Preferred Share and at an annual rate of US$1.10 per share, for aggregate gross proceeds of US$200 million.

On August 30, 2012, SEMCO entered into an agreement for a new US$100 million unsecured credit facility which is available for working capital purposes and expires on August 30, 2014.

On September 28, 2012, AltaGas issued $350 million of senior unsecured MTNs. The notes carry a coupon rate of 3.72 percent and mature on September 28, 2021.

On September 28, 2012, AltaGas extended its US$300 million unsecured credit facility with three Canadian chartered banks. The credit facility's term was extended with a new maturity date of September 2, 2014.

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 on November 13, 2015.

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 5-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.

Credit facilities ($ millions)		Borrowing capacity		**Drawn at June 30 2013**		Drawn at December 31 2012
Demand operating facilities	$	70.0	**$**	**3.4**	$	6.1
Extendible revolving letter of credit facility		75.0		**50.9**		50.0
PNG operating facility		25.0		**7.9**		15.4
Bilateral letter of credit facility		125.0		**122.0**		89.8
AltaGas Ltd. revolving credit facility (1)		600.0		**249.3**		227.3
Utility Group revolving credit facility		200.0		**-**		131.3
USD unsecured credit facility (1) (2)		300.0		**187.6**		170.0
SEMCO Energy USD unsecured credit facility (1) (2)		100.0		**0.8**		50.2
	$	1,495.0	**$**	**621.9**	$	740.1

(1) *Amount drawn at June 30, 2013 converted at June 2013 month-end rate of 1 U.S. dollar = 1.0512 Canadian dollar (Amount drawn at December 31, 2012 converted at December 2012 month-end rate of 1 U.S. dollar = 0.9949 Canadian dollar).*

(2) *Borrowing capacity assumed at par.*

RELATED PARTIES

AltaGas and one of its managers agreed on a loan in the principal amount of $750 thousand, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015 (December 31, 2012 - $750 thousand).

SHARE INFORMATION

As at June 30, 2013, AltaGas had 118.4 million common shares, 8.0 million series A preferred shares and 8.0 million series C USD preferred shares outstanding with a combined market capitalization of approximately $4.8 billion based on a closing trading price on June 30, 2013 of $36.86 per common share, $25.50 per series A preferred share and $25.32 per series C USD preferred share. As at June 30, 2013, there were 5.2 million options outstanding and 2.3 million options exercisable under the terms of the share option plan.

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends are determined by giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements.

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.

The following table summarizes AltaGas' dividend declaration history:

Dividends
Years ended December 31

($ per common share)		**2013**		2012
First quarter	**$**	**0.36**	$	0.345
Second quarter		**0.37**		0.345
Third quarter		**-**		0.35
Fourth quarter		**-**		0.36
Total	**$**	**0.73**	$	1.40

Series A Preferred Share Dividends
Years ended December 31

($ per preferred share)		**2013**		2012
First quarter	**$**	**0.3125**	$	0.3125
Second quarter		**0.3125**		0.3125
Third quarter		**-**		0.3125
Fourth quarter		**-**		0.3125
Total	**$**	**0.625**	$	1.25

Series C Preferred Share Dividends
Years ended December 31

(US$ per preferred share)		**2013**		2012
First quarter	**$**	**0.275**		-
Second quarter		**0.275**		-
Third quarter		**-**		0.3473
Fourth quarter		**-**		0.275
Total	**$**	**0.55**	$	0.6223

SIGNIFICANT ACCOUNTING POLICIES

Reference should be made to the audited Consolidated Financial Statements as at and for the year ended December 31, 2012 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' 2012 Financial Report and the notes to the interim Consolidated Financial Statements for the three and six months ended June 30, 2013.

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 (DC&P) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

AltaGas' management is responsible for establishing and maintaining DC&P 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, DC&P 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 second quarter 2013, 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

($ millions)	**Q2-13**	Q1-13	Q4-12	Q3-12	Q2-12	Q1-12	Q4-11	Q3-11
Total revenue	**458.6**	613.5	525.8	290.0	272.2	361.7	334.9	300.4
Net revenue(1)	**211.8**	237.1	207.6	146.3	144.0	166.5	156.0	115.6
Operating income(1)	**66.8**	107.7	81.7	33.4	29.4	69.6	49.1	33.5
Net income before taxes	**39.6**	76.4	51.8	18.8	37.9	57.8	44.6	18.0
Net income applicable to common shares(2)	**35.9**	49.0	26.7	8.0	25.8	41.3	31.6	11.1

($ per share)	**Q2-13**	Q1-13	Q4-12	Q3-12	Q2-12	Q1-12	Q4-11	Q3-11
Net income applicable to common shares								
Basic(2)	**0.31**	0.46	0.25	0.07	0.29	0.46	0.37	0.13
Diluted(2)	**0.30**	0.45	0.25	0.07	0.28	0.45	0.36	0.13
Dividends declared	**0.37**	0.36	0.36	0.35	0.345	0.345	0.34	0.33

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

(2) *Amounts may not add due to rounding.*

Significant items that impacted individual quarterly earnings were as follows:

- In the third and fourth quarters 2011, turnarounds at Harmattan and Younger facilities reduced revenue and increased operating expenses resulting in lower operating income of approximately $12 million before taxes. These turnarounds have occurred every three years;
- In fourth quarter 2011, AltaGas acquired all the outstanding common shares of PNG for $224 million including assumed debt of approximately $86 million. In the quarter, AltaGas recorded $5.7 million in pre-tax transaction costs primarily related to the acquisition of PNG and other business development related activities;
- In second quarter 2012, AltaGas recorded $3.5 million gain from the settlement of a dispute with a gas processing customer;
- In third quarter 2012, AltaGas completed the acquisition of SEMCO for total consideration of US$1.156 billion including US$371 million in assumed debt, adding approximately US$725 million in regulated rate base. In the quarter, AltaGas recorded $12.5 million in pre-tax transaction costs and foreign exchange losses primarily related to the acquisition of SEMCO and other business development related activities;
- In fourth quarter 2012, AltaGas wrote down $2.9 million related to two wind projects under development;
- In fourth quarter 2012, AltaGas received independent arbitration panel ruling regarding a claim of force majeure on Sundance B Unit 3 facility. 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 $1.3 million in pre-tax transaction costs; and
- 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.

Consolidated Balance Sheets
(condensed and unaudited)

As at *($ thousands)*	**June 30 2013**	December 31 2012
ASSETS		
Current assets		
Cash and cash equivalents	**$ 95,530**	$ 11,827
Accounts receivable	**279,400**	382,610
Inventory *(note 5)*	**115,655**	94,709
Restricted cash holdings from customers	**26,182**	28,626
Regulatory assets	**3,316**	4,344
Risk management assets *(note 8)*	**25,989**	47,788
Prepaid expenses and other current assets	**23,038**	21,456
Deferred income taxes	**1,911**	16,375
	571,021	607,735
Property, plant and equipment	**4,719,323**	3,949,166
Intangible assets	**190,586**	189,790
Goodwill *(note 6)*	**739,482**	714,902
Regulatory assets	**280,651**	275,263
Risk management assets *(note 8)*	**14,690**	18,132
Deferred income taxes	**9,675**	8,962
Long-term investments and other assets *(note 8)*	**28,643**	24,969
Investments accounted for by equity method	**150,271**	148,358
	$ 6,704,342	$ 5,937,277
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 304,013**	$ 370,011
Dividends payable	**14,798**	12,640
Short-term debt	**8,086**	66,938
Current portion of long-term debt *(notes 7 and 8)*	**212,782**	9,302
Customer deposits	**43,838**	51,756
Regulatory liabilities	**4,004**	1,971
Risk management liabilities *(note 8)*	**24,917**	39,734
Deferred income taxes	**1,331**	12,539
Other current liabilities	**10,010**	10,301
	623,779	575,192
Long-term debt *(notes 7 and 8)*	**2,810,842**	2,626,086
Asset retirement obligations	**61,048**	56,632
Deferred income taxes	**438,347**	404,072
Regulatory liabilities	**110,417**	104,282
Risk management liabilities *(note 8)*	**7,550**	10,526
Other long-term liabilities	**37,566**	33,786
Future employee obligations	**133,098**	126,904
	4,222,647	3,937,480

As at ($ thousands)	**June 30 2013**	December 31 2012
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 118.38 million issued and outstanding *(note 9)*	**2,070,975**	1,639,895
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 9)*	**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 9)*	**200,626**	200,626
Contributed surplus	**11,602**	10,570
Accumulated deficit	**(66,825)**	(69,979)
Accumulated other comprehensive loss	**28,675**	(15,447)
Total shareholders' equity	**2,439,179**	1,959,791
Non-controlling interests	**42,516**	40,006
	$ 6,704,342	$ 5,937,277

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ thousands except per share amounts)	Three months ended June 30 2013	Three months ended June 30 2012	Six months ended June 30 2013	Six months ended June 30 2012
REVENUE				
Operating	**$ 460,236**	$ 248,541	**$ 1,080,759**	$ 609,034
Unrealized gain (loss) on risk management contracts *(note 8)*	**(1,625)**	23,643	**(8,679)**	24,800
	458,611	272,184	**1,072,080**	633,834
EXPENSES				
Cost of sales, exclusive of items shown separately	**297,168**	126,831	**689,547**	335,968
Operating and administrative	**107,921**	69,691	**207,772**	143,340
Accretion of asset retirement obligations	**926**	768	**1,892**	1,583
Depreciation, depletion and amortization	**37,786**	20,529	**73,473**	41,812
	443,801	217,819	**972,684**	522,703
Income (loss) from equity investments	**49,546**	(80)	**66,164**	12,065
Other income (expense)	**888**	(1,298)	**305**	515
Foreign exchange gain (loss)	**(396)**	(2,015)	**4**	(2,149)
Interest expense				
Short-term debt	**824**	448	**1,145**	905
Long-term debt	**24,395**	12,617	**48,689**	24,922
Income before income taxes	**39,629**	37,907	**116,035**	95,735
Income tax expense				
Current	**2,301**	806	**8,831**	3,970
Deferred	**(5,181)**	7,881	**9,295**	18,477
Net income after taxes	**42,509**	29,220	**97,909**	73,288
Net income applicable to non-controlling interests	**1,752**	338	**3,394**	637
Net income applicable to controlling interests	**40,757**	28,882	**94,515**	72,651
Preferred share dividends	**4,813**	3,090	**9,547**	5,590
Net income applicable to common shares	**$ 35,944**	$ 25,792	**$ 84,968**	$ 67,061
Net income per common share *(note 10)*				
Basic	**$ 0.31**	$ 0.29	**$ 0.76**	$ 0.75
Diluted	**$ 0.30**	$ 0.28	**$ 0.74**	$ 0.74
Weighted average number of common shares outstanding *(note 9)* *($ thousands)*				
Basic	**117,676**	90,049	**111,734**	89,770
Diluted	**120,946**	91,225	**115,222**	91,060

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(condensed and unaudited)

($ thousands)	Three months ended June 30 **2013**	2012	Six months ended June 30 **2013**	2012
Net income after taxes	**$ 42,509**	$ 29,220	**$ 97,909**	$ 73,288
Total other comprehensive income (loss) (net of taxes)	**33,039**	960	**28,675**	(10,880)
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**$ 75,548**	$ 30,180	**$ 126,584**	$ 62,408
Comprehensive income attributable to:				
Non-controlling interests	**$ 1,752**	$ 338	**$ 3,394**	$ 637
Common shareholders	**73,796**	29,842	**123,190**	61,771
	$ 75,548	$ 30,180	**$ 126,584**	$ 62,408

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

($ thousands)	**Available-for-sale**	**Cash flow hedges**	**Defined benefit pension plans**	**Hedge net investments**	**Translation foreign operations**	**Total**
Opening balance, January 1, 2013	$ (5,787)	$ (994)	$ (10,246)	$ (2,263)	$ 3,843	$ (15,447)
Other comprehensive income before reclassification	(751)	(232)	-	(28,056)	72,334	43,295
Amounts reclassified from other comprehensive income *(note 3)*	-	360	467	-	-	827
Net current period other comprehensive income (loss)	$ (751)	$ 128	$ 467	$ (28,056)	$ 72,334	$ 44,122
Ending balance, June 30, 2013[(2) (3) (4)]	**$ (6,538)**	**$ (866)**	**$ (9,779)**	**$ (30,319)**	**$ 76,177**	**$ 28,675**
Opening balance, January 1, 2012	$ (5,895)	$ (2,803)	$ (3,142)	-	-	$ (11,840)
Other comprehensive income (loss) before reclassification	279	-	-	-	-	279
Amounts reclassified from other comprehensive income *(note 3)*	-	573	108	-	-	681
Net current period other comprehensive income (loss)	$ 279	$ 573	$ 108	-	-	$ 960
Ending balance, June 30, 2012[(2) (3) (4) (5)]	$ (5,616)	$ (2,230)	$ (3,034)	-	-	$ (10,880)

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

(2) *Available-for-sale - net of tax recovery $948 (June 30, 2012 - tax recovery $802).*

(3) *Cash flow hedges - net of tax recovery $78 (June 30, 2012 - tax recovery $297).*

(4) *Defined benefit pension plans - net of tax recovery $3,394 (June 30, 2012 - tax recovery $1,029).*

(5) *Hedge net investment - net of tax recovery $4,359 (June 30, 2012 - $nil).*

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

($ thousands)	Six months ended June 30 2013	2012
Common shares (note 9)		
Balance, beginning of period	**$ 1,639,895**	$ 1,204,269
Shares issued for cash on exercise of options	**13,473**	8,166
Shares issued under DRIP [1]	**28,715**	17,212
Shares issued on public offering	**388,892**	-
Balance, end of period	**2,070,975**	1,229,647
Preferred shares (note 9)		
Balance, beginning of period	**394,752**	194,126
Series C issued	**-**	199,334
Balance, end of period	**394,752**	393,460
Contributed surplus		
Balance, beginning of period	**10,570**	7,441
Share options expense	**2,538**	1,775
Exercise of share options	**(977)**	(316)
Forfeiture of share options	**(529)**	(147)
Balance, end of period	**11,602**	8,753
Accumulated deficit		
Balance, beginning of period	**(69,979)**	(38,634)
Net income applicable to controlling interests	**94,515**	72,651
Common share dividends	**(81,814)**	(61,986)
Preferred share dividends	**(9,547)**	(5,590)
Balance, end of period	**(66,825)**	(33,559)
Accumulated other comprehensive income (loss)		
Balance, beginning of period	**(15,447)**	(11,840)
Other comprehensive income	**44,122**	960
Balance, end of period	**28,675**	(10,880)
Total shareholders' equity	**2,439,179**	1,587,421
Non-controlling interests		
Balance, beginning of period	**40,006**	5,426
Net income applicable to non-controlling interests	**3,394**	637
Business acquisition	**-**	7,939
Acquisition of non-controlling interests	**-**	(5,205)
Distribution by subsidiaries to non-controlling interests	**(884)**	(587)
Balance, end of period	**42,516**	8,210
Total equity	**$ 2,481,695**	$ 1,595,631

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

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

($ thousands)	Three months ended June 30 2013	2012	Six months ended June 30 2013	2012
Cash from operations				
Net income after taxes	**$ 42,509**	$ 29,220	**$ 97,909**	$ 73,288
Items not involving cash:				
Depreciation, depletion and amortization	**37,786**	20,529	**73,473**	41,812
Accretion of asset retirement obligations	**926**	768	**1,892**	1,583
Share-based compensation	**1,070**	748	**2,010**	1,313
Deferred income tax expense (recovery)	**(5,181)**	7,881	**9,295**	18,477
Gain on sale of assets	**-**	-	**(12)**	-
Income from equity investments	**(49,546)**	80	**(66,164)**	(12,065)
Unrealized (gains) losses on risk management contracts	**1,625**	(23,643)	**8,679**	(24,800)
Unrealized (gains) losses on held-for-trading investments	**(87)**	1,381	**949**	(345)
Other	**1,670**	(920)	**2,230**	1,760
Asset retirement obligations settled	**(157)**	(67)	**(650)**	(516)
Distributions from equity investments	**51,530**	3,181	**73,871**	11,402
Changes in operating assets and liabilities:				
Accounts receivable	**106,493**	33,219	**119,504**	53,286
Inventory	**(36,495)**	(2,460)	**(12,093)**	(1,165)
Other current assets	**1,409**	(177)	**1,378**	1,297
Regulatory assets (current)	**1,859**	1,819	**1,199**	4,192
Accounts payable and accrued liabilities	**(19,553)**	(39,812)	**(71,996)**	(46,118)
Customer deposits	**(5,546)**	256	**(14,655)**	6,437
Regulatory liabilities (current)	**(444)**	(1,295)	**2,855**	970
Other current liabilities	**3,265**	1,895	**(1,850)**	(3,303)
Other operating assets and liabilities	**6,481**	7,276	**14,366**	11,187
	139,614	39,879	**242,190**	138,692
Investing activities				
Change in restricted cash holdings from customers	**316**	(522)	**2,681**	(6,859)
Acquisition of property, plant and equipment	**(120,501)**	(181,368)	**(223,064)**	(384,258)
Acquisition of intangible assets	**(1,403)**	(15)	**(5,057)**	(15)
Proceeds from disposition of property, plant and equipment	**146**	-	**368**	-
Acquisition of long-term investments	**-**	(1,000)	**-**	(4,000)
Contributions to equity investments	**(223)**	(266)	**(6,654)**	(433)
Business acquisitions, net of cash acquired	**(536,802)**	-	**(536,802)**	(34,705)
	(658,467)	(183,171)	**(768,528)**	(430,270)

($ thousands)	Three months ended June 30 2013	2012	Six months ended June 30 2013	2012
Financing activities				
Net issuance (repayment) of short-term debt	**(236,620)**	(2,688)	**(61,917)**	(1,973)
Issuance of long-term debt, net of debt issuance costs	**932,959**	199,410	**1,033,028**	467,296
Repayment of long-term debt	**(469,049)**	(228,014)	**(701,576)**	(330,852)
Dividends - common shares	**(41,651)**	(31,085)	**(79,656)**	(61,925)
Dividends - preferred shares	**(4,813)**	(3,090)	**(9,547)**	(5,590)
Distributions to non-controlling interest	**-**	(587)	**(884)**	(587)
Net proceeds from issuance of common shares	**408,757**	11,204	**430,106**	25,380
Net proceeds from issuance of preferred shares	**-**	199,334	**-**	199,334
	589,583	144,484	**609,554**	291,083
Effect of exchange rate changes on cash and cash equivalents	**308**	-	**487**	-
Change in cash and cash equivalents	**71,038**	1,192	**83,703**	(495)
Cash and cash equivalents, beginning of period	**24,492**	1,188	**11,827**	2,875
Cash and cash equivalents, end of period	**$ 95,530**	$ 2,380	**$ 95,530**	$ 2,380

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

($ thousands)	Three months ended June 30 2013	2012	Six months ended June 30 2013	2012
Interest paid (net of capitalized interest)	**$ 22,193**	$ 9,674	**$ 47,377**	$ 24,730
Income taxes paid	**$ 2,772**	$ 1,694	**$ 5,872**	$ 6,764

See accompanying notes to the 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 Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., SEMCO Energy Inc. (SEMCO) and AltaGas Power Holdings (U.S.) Inc., (collectively, the operating subsidiaries).

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas has three operating 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 Power segment includes 1,096 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets.

The Utilities segment is predominantly comprised of natural gas distribution rate-regulated utilities, where financial results are generally based on a regulated allowed return on capital invested. 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.

The regulated utilities businesses in Canada are natural gas distribution utilities and are comprised of AltaGas Utilities Inc. (AUI) in Alberta, Pacific Northern Gas Ltd. (PNG) in British Columbia and Heritage Gas Limited (Heritage Gas) in Nova Scotia. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. Through Heritage Gas, AltaGas is also operating and developing a non-rate-regulated compressed natural gas (CNG) distribution business in Nova Scotia.

The Utilities business in the United States is comprised mainly of SEMCO Energy Gas Company (SEMCO Gas) in Michigan, and ENSTAR Natural Gas Company (ENSTAR) and a 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited condensed 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 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 2012 annual audited Consolidated Financial Statements prepared in accordance with US GAAP. In management's opinion, the interim condensed 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 on July 4, 2011 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, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

These unaudited condensed 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.

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 interim condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2012 US GAAP annual audited Consolidated Financial Statements, except as described below.

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 U.S. dollar to a Canadian dollar for the period ended June 30, 2013 was 1.0512 (year ended December 31, 2012 - 0.9949). 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 "Other comprehensive income" (OCI). The average exchange rate used to convert a U.S. dollar to a Canadian dollar for the period ended June 30, 2013 was 1.0161 (second quarter 2012 - 0.9955).

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: amortization, asset impairment, litigation, environmental and asset retirement obligations, financial instruments, pension plans and other post-retirement benefits, share-based compensation, income taxes 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

Balance Sheet Disclosures - Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update (ASU) which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, FASB issued ASU No. 2013-01 “Clarifying the Scope of Disclosure about Offsetting Assets and Liabilities”. The objective of ASU No. 2013-01 is to clarify that the scope of ASU No. 2011-11 would apply to derivatives including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions. ASU No. 2011-11 and ASU No. 2013-01 are effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The update required additional disclosure with no impact on the financial results.

Comprehensive Income and Equity

In June 2011, FASB issued ASU No. 2011-05, "Other Comprehensive Income". In February 2013, FASB issued ASU No. 2013-02 “Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income”. These standards amend Accounting Standards Codification (ASC) 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The adoption of these updates change the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, with no other impact to the financial statements. These amendments are effective on or after December 15, 2012. The update required additional disclosure with no impact on the financial results.

CHANGE IN ACCOUNTING POLICIES

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, FASB issued ASU No. 2013-04, “Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date”. The objective of this update is to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The update is effective for fiscal years, and interim periods within those years, beginning after December 31, 2013. Management has assessed that this update does not have any impact on the preparation and presentation of AltaGas’ interim consolidated financial statements at June 30, 2013.

Parent’s Accounting for the Cumulative Translation Adjustment

In March 2013, FASB issued ASU No. 2013-05, “Parent’s accounting for the Cumulative Translation Adjustment upon De-recognition of Certain Subsidiaries or Group of Assets within a Foreign Entity or of an Investment in a Foreign Entity”. This update applies to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets within a foreign entity. The update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Management has assessed that this update does not have any impact on the preparation and presentation of AltaGas’ interim consolidated financial statements at June 30, 2013.

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

AOCI components reclassified	Income Statement line item affected	**Three months ended June 30, 2013**	**Six months ended June 30, 2013**
Cash flow hedges			
Commodity contracts – Bond forward	Interest expense – Long-term debt	**$ 181**	**$ 360**
Defined benefit pension plans	Operating and administrative expense	**342**	**647**
	Total before income taxes	**523**	**1,007**
Deferred income taxes	Income tax expenses – Deferred	**(70)**	**(180)**
		$ 453	**$ 827**

AOCI components reclassified	Income Statement line item	Three months ended June 30, 2012	Six months ended June 30, 2012
Cash flow hedges			
Commodity contracts - NGL (ineffective hedge)	Unrealized gains (losses) on risk management contracts	$ 1,062	$ 320
Commodity contracts – Bond forward	Interest expense – Long-term debt	167	333
Defined benefit pension plans	Operating and administrative expense	72	144
	Total before income taxes	1,301	797
Deferred income taxes	Income tax expenses – Deferred	(283)	(116)
		$ 1,018	$ 681

4. BUSINESS ACQUISITION

BLYTHE

On May 16, 2013, AltaGas, through a wholly owned subsidiary AltaGas Power Holdings (U.S.) Inc., completed the acquisition of Blythe Energy, LLC (Blythe), which owns the 507 MW natural gas-fired power plant (Blythe Energy Center), associated major spare parts, and a related 230 kV 67-mile electric transmission line in Southern California, for US$515 million before adjustments for working capital. The Blythe Energy Center is contracted under a Power Purchase Arrangement (PPA) through to July 2020 with Southern California Edison (SCE). Contract provisions match PPA revenues to all major plant costs. The Blythe Energy Center is positioned upon expiry of the PPA in 2020 to contract with other market participants due to its location and its ability to serve both the California Independent System Operator and the Desert Southwest markets.

AltaGas paid an aggregate purchase price of $536.8 million. AltaGas financed the acquisition through a combination of $405 million gross proceeds from 11,615,000 common shares public offering and the remainder from a US$300 million senior unsecured revolving credit facility with three Canadian chartered banks. Transaction costs such as legal, accounting, valuation and other professional fees related specifically to the acquisition were $1.3 million pre-tax and have been expensed in the Consolidated Statement of Income, within "Operating and administrative expenses".

Below is a provisional purchase price allocation based on the statement of financial position as at May 16, 2013, using an exchange rate of 1.0163 to convert a U.S. dollar to Canadian dollar.

Cash consideration	$	536,802
Total consideration	**$**	**536,802**
Purchase price allocation		
Assets acquired:		
Current assets	$	20,152
Property, plant and equipment		544,971
Non-current assets		4,924
	$	570,047
Less liabilities assumed:		
Current liabilities	$	9,354
Deferred income taxes		21,649
Asset retirement obligations		2,242
		33,245
	$	**536,802**

5. INVENTORY

As at		**June 30 2013**		December 31 2012
Natural gas held in storage	**$**	**101,357**	$	86,005
Other inventory		**14,298**		8,704
	$	**115,655**	$	94,709

6. GOODWILL

As at		**June 30 2013**		December 31 2012
Balance, beginning of period	**$**	**714,902**	$	281,123
Business acquisition		**-**		430,024
Foreign exchange translation		**24,580**		3,755
	$	**739,482**	$	714,902

7. LONG-TERM DEBT

	Maturity date	**June 30 2013**	December 31 2012
Credit facilities			
$35 million PNG 5-year revolver - 4.36 percent(1) (9)	30-Jan-2015	**-**	$ 30,000
$200 million Utility Group(2)	17-Nov-2015	**-**	131,342
$600 million Unsecured extendible revolving(2) (3)	30-May-2016	**249,345**	227,345
US$300 million Unsecured(2)	02-Sep-2014	**187,639**	169,133
Medium-term notes			
$200 million Senior unsecured - 7.42 percent	29-Apr-2014	**200,000**	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**	
US$175 million Senior unsecured - floating(8)	13-Apr-2015	**183,960**	-
SEMCO long-term debt			
US$5 million SEMCO secured - 7.03 percent	25-Nov-2013	**5,231**	4,923
US$90 million CINGSA secured construction and term loan(4)	14-Nov-2015	**86,304**	77,105
US$300 million SEMCO Senior secured - 5.15 percent(5)	21-Apr-2020	**315,360**	298,470
Debenture notes			
PNG RoyNat Debenture - 3.72 percent(1)	15-Sep-2017	**11,600**	12,200
PNG 2018 Series Debenture - 8.75 percent(1)	15-Nov-2018	**11,600**	11,600
PNG 2024 CFI Debenture - 7.39 percent(6)	01-Nov-2024	**8,130**	8,353
PNG 2025 Series Debenture - 9.30 percent(1)	18-Jul-2025	**15,500**	15,500
PNG 2027 Series Debenture - 6.90 percent(1)	02-Dec-2027	**16,500**	16,500
Loan from Province of Nova Scotia(7)	31-Jul-2017	**4,072**	3,964
SEMCO capital lease obligation - 3.50 percent	01-May-2040	**465**	445
Promissory notes	25-Oct-2015	**2,379**	2,866
Other long-term debt		**539**	642
		3,023,624	2,635,388
Less current portion		**212,782**	9,302
		$ 2,810,842	$ 2,626,086

(1) *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.*

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

(3) *The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million.*

(4) *Borrowings on the facility can be by way of LIBOR loans or alternative base rate loans. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. The facility is non-recourse to the CINGSA subsidiary.*

(5) *Collateral for the USD MTNs is certain SEMCO assets.*

(6) *Collateral for the 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.*

(7) *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.*

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

(9) *The facility was early terminated on June 7, 2013.*

8. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

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

Fair Values of Financial Instruments

The fair 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 interest rate and 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		**June 30 2013**		December 31 2012
Current portion of long-term debt				
Carrying amount	**$**	**212,782**	$	9,302
Fair value of current portion of long-term debt	**$**	**216,952**	$	10,243

Summary of Fair Values		**June 30 2013**		December 31 2012
Long-term debt excluding non-financial instruments				
Carrying amount	**$**	**2,810,842**	$	2,626,086
Fair value of long-term debt excluding non-financial instruments	**$**	**2,912,293**	$	2,800,759

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

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

June 30, 2013	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	**$ 95,530**	**-**	**-**	**$ 95,530**
Risk management assets - current	**-**	**$ 25,989**	**-**	**$ 25,989**
Risk management assets - non-current	**-**	**$ 14,690**	**-**	**$ 14,690**
Long-term investments and other assets	**$ 5,850**	**-**	**-**	**$ 5,850**
Financial liabilities				
Risk management liabilities - current	**-**	**$ 24,917**	**-**	**$ 24,917**
Risk management liabilities - non-current	**-**	**$ 7,550**	**-**	**$ 7,550**
Current portion of long-term debt	**-**	**$ 216,952**	**-**	**$ 216,952**
Long-term debt	**-**	**$ 2,912,293**	**-**	**$ 2,912,293**

December 31, 2012	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	$ 11,827	-	-	$ 11,827
Risk management assets - current	-	$ 47,788	-	$ 47,788
Risk management assets - non-current	-	$ 18,132	-	$ 18,132
Long-term investments and other assets	$ 7,715	-	-	$ 7,715
Financial Liabilities				
Risk management liabilities - current	-	$ 39,734	-	$ 39,734
Risk management liabilities - non-current	-	$ 10,526	-	$ 10,526
Current portion of long-term debt	-	$ 10,243	-	$ 10,243
Long-term debt	-	$ 2,800,759	-	$ 2,800,759

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

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Natural gas	**$ (955)**	$ (7,953)	**$ (1,833)**	$ (12,086)
Storage optimization	**1,752**	(1,448)	**82**	16
NGL Frac Spread	**342**	36,634	**(254)**	32,665
Power	**(2,514)**	(3,780)	**(5,397)**	4,972
Heat rate	**(53)**	171	**(267)**	(360)
Interest rate swaps	**-**	(60)	**-**	(53)
Foreign exchange	**(197)**	79	**(545)**	(354)
Embedded derivative	**-**	-	**(465)**	-
	$ (1,625)	$ 23,643	**$ (8,679)**	$ 24,800

Summary of Unrealized Gains (Losses) and Tax Recovery (Expense) on Financial Instruments Recognized in AOCI

	Unrealized (losses)	Tax recovery	Six months ended June 30 2013	Unrealized (losses)	Tax recovery	Six months ended June 30 2012
Available-for-sale	**$ (7,486)**	**$ 948**	**$ (6,538)**	$ (6,418)	$ 802	$ (5,616)
Bond forward	**(634)**	**-**	**(634)**	(1,340)	-	(1,340)
NGL Frac Spread	**(310)**	**78**	**(232)**	(1,187)	297	(890)
AOCI	**$ (8,430)**	**$ 1,026**	**$ (7,404)**	$ (8,945)	$ 1,099	$ (7,846)

Offsetting of Derivative Assets and Derivative Liabilities

As at June 30, 2013

Risk management assets	Gross amounts of recognized assets	Gross amounts offset in Balance Sheet	Net amounts of assets presented in Balance Sheet
Natural gas	**$ 66,621**	**$ 47,377**	**$ 19,244**
Storage optimization	**352**	**20**	**332**
	$ 66,973	**$ 47,397**	**$ 19,576**

As at June 30, 2013

Risk management liabilities	Gross amounts of recognized liabilities	Gross amounts offset in Balance Sheet	Net amounts of liabilities presented in Balance Sheet
Natural gas	**$ 63,585**	**$ 47,377**	**$ 16,208**
Storage optimization	**37**	**20**	**17**
Total	**$ 63,622**	**$ 47,397**	**$ 16,225**

As at June 30, 2012

Risk management assets	Gross amounts of recognized assets	Gross amounts offset in Balance Sheet	Net amounts of assets presented in Balance Sheet
Natural gas	$ 132,906	$ 88,327	$ 44,579
Storage optimization	96	91	5
	$ 133,002	$ 88,418	$ 44,584

As at June 30, 2012

Risk management liabilities	Gross amounts of recognized liabilities	Gross amounts offset in Balance Sheet	Net amounts of liabilities presented in Balance Sheet
Natural gas	$ 131,165	$ 88,327	$ 42,838
Storage optimization	144	91	53
	$ 131,309	$ 88,418	$ 42,891

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 common shares of Alterra Power Corp. (Alterra), through a private equity offering. These 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 June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Financial assets available-for-sale	**$ 70**	$ (1,120)	**$ (751)**	$ 280

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

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Financial assets held-for-trading	**$ 86**	$ (1,381)	**$ (949)**	$ 345

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

9. SHAREHOLDERS' EQUITY

Authorization

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

On 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.

Common Shares Issued and Outstanding	Number of shares	Amount
January 1, 2012	89,248,374	$ 1,204,269
Shares issued for cash on exercise of options	779,969	16,197
Shares issued under DRIP	1,393,541	41,071
Shares issued on conversion of subscription receipts	13,915,000	378,358
December 31, 2012	105,336,884	$ 1,639,895
Shares issued for cash on exercise of options	**581,488**	**13,473**
Shares issued under DRIP	**847,762**	**28,715**
Shares issued on public offering	**11,615,000**	**388,892**
Issued and outstanding at June 30, 2013	**118,381,134**	**$ 2,070,975**

Preferred Shares Series A Issued and Outstanding	Number of shares	Amount
January 1, 2012	8,000,000	194,126
December 31, 2012	8,000,000	$ 194,126
Issued and outstanding at June 30, 2013	**8,000,000**	**$ 194,126**

Preferred Shares Series C Issued and Outstanding	Number of shares	Amount
January 1, 2012	-	-
Shares issued on public offering	8,000,000	200,626
December 31, 2012	8,000,000	$ 200,626
Issued and outstanding at June 30, 2013	**8,000,000**	**$ 200,626**

	Three months ended June 30		Six months ended June 30	
Weighted Average Shares Outstanding	**2013**	2012	**2013**	2012
Number of shares - basic	**117,676,420**	90,048,663	**111,734,089**	89,770,098
Dilutive equity instruments (1)	**3,269,861**	1,176,590	**3,488,384**	1,289,820
Number of shares - diluted	**120,946,281**	91,225,253	**115,222,473**	91,059,918

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares at June 30, 2013 and 2012, respectively.*

For six months ended June 30, 2013, 113,000 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (December 31, 2012 - 668,516 options).

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at June 30, 2013, 6,671,003 shares were reserved for issuance under the plan. As at June 30, 2013, options granted under the plan generally have a term of 10 years until expiry and vest no longer than over a four-year period.

As at June 30, 2013, the unexpensed fair value of share option compensation cost associated with future periods was $5.2 million (December 31, 2012 - $7.9 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, 2012	5,846,460	$ 25.01
Granted	164,000	35.58
Exercised	(581,488)	21.50
Expired	(1,875)	27.56
Forfeited	(259,987)	26.50
Share options outstanding, June 30, 2013	**5,167,110**	**$ 25.67**
Share options exercisable, June 30, 2013	**2,257,326**	**$ 22.34**

(1) *Weighted average.*

The following table summarizes the employee share option plan as at June 30, 2013:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Exercise price
$9.48 to $15.25	368,185	$ 14.25	5.42	368,185	$ 14.25
$15.26 to $25.08	1,867,875	20.42	6.58	1,116,275	20.60
$25.09 to $38.88	2,931,050	30.45	8.16	772,866	28.72
	5,167,110	**$ 25.67**	**7.39**	**2,257,326**	**$ 22.34**

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. 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 three years. For three months ended June 30, 2013, the compensation expense recorded was $1.4 million (June 30, 2012 - $2.6 million).

As at June 30, 2013, the unexpensed fair value of equity-based compensation cost associated with future periods was $9.4 million (December 31, 2012 - $8.8 million).

10. NET INCOME APPLICABLE TO COMMON SHARES

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

	Three months ended		Six months ended	
	June 30 2013	June 30 2012	**June 30 2013**	June 30 2012
Numerator:				
Net income applicable to controlling interests	**$ 40,757**	$ 28,882	**$ 94,515**	$ 72,651
Less: Preferred share dividends	**4,813**	3,090	**9,547**	5,590
Net income applicable to common shares	**$ 35,944**	$ 25,792	**$ 84,968**	$ 67,061
Denominator:				
Weighted average number of common shares outstanding	**117,676**	90,049	**111,734**	89,770
Dilutive equity instruments(1)	**3,270**	1,176	**3,488**	1,290
Weighted average number of common shares outstanding - diluted	**120,946**	91,225	**115,222**	91,060
Basic net income applicable per common share	**$ 0.31**	$ 0.29	**$ 0.76**	$ 0.75
Diluted net income applicable per common share	**$ 0.30**	$ 0.28	**$ 0.74**	$ 0.74

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares at June 30, 2013 and 2012, respectively.*

11. 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 2013 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 $12.3 million over the next 9 years, of which $6.0 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 $3.3 million per annum over the term of the contract for storage services.

In 2010, AltaGas entered into a 60-year Consumer Price Index indexed Energy Purchase Arrangement with BC Hydro for the Northwest run-of-river projects. At June 30, 2013, AltaGas is committed to pay approximately $102.7 million for construction work related to these projects which are expected to be in service in 2014 and 2015. As at June 30, 2013, approximately $28.8 million of the total initial consideration of $90.0 million (recognized as "'Intangible assets") is remaining to be paid to BC Hydro in support of the construction and operation of the Northwest Transmission Line. The amount of $28.8 million is recorded in "Accounts payable and accrued liabilities" was paid on July 2, 2013. After commercial operation date, AltaGas shall make a series of 20 annual payments (annual considerations), the first of which shall be in the amount of approximately $4.9 million, and annually thereafter in the amount of approximately $9.8 million adjusted for inflation. Annual considerations have not been recognized in the statement of financial position as at June 30, 2013.

12. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post retirement 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:

	Defined benefit plans		Post-retirement benefit plans	
	June 30	June 30	**June 30**	June 30
Three months ended	**2013**	2012	**2013**	2012
Current service cost	**$ 3,108**	$ 1,154	**$ 465**	$ 102
Interest cost	**2,995**	1,140	**697**	135
Expected return on plan assets	**(3,428)**	(851)	**(836)**	(15)
Cost of special events	**60**	-	**-**	-
Amortization of past service cost	**32**	19	**(58)**	-
Amortization of net actuarial loss	**1,257**	170	**145**	18
Amortization of regulatory asset	**748**	-	**160**	-
Net benefit cost recognized	**$ 4,772**	$ 1,632	**$ 573**	$ 240

	Defined benefit plans		Post-retirement benefit plans	
	June 30	June 30	**June 30**	June 30
Six months ended	**2013**	2012	**2013**	2012
Current service cost	**$ 6,194**	$ 2,298	**$ 927**	$ 204
Interest cost	**5,964**	2,309	**1,387**	271
Expected return on plan assets	**(6,822)**	(1,720)	**(1,666)**	(30)
Cost of special events	**122**	-	**-**	-
Amortization of past service cost	**63**	38	**(116)**	-
Amortization of net actuarial loss	**2,499**	385	**289**	38
Amortization of regulatory asset	**1,491**	-	**318**	-
Net benefit cost recognized	**$ 9,511**	$ 3,310	**$ 1,139**	$ 483

13. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

14. 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.

15. 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; – energy consulting and purchase and sale of natural gas and electricity; and – natural gas storage facilities.
Power	– coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase arrangements; – gas-fired power plants in Alberta; and – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
Corporate	– the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

The following tables show the composition by segment:

Three months ended June 30, 2013 (unaudited)	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 254,887**	**$ 65,427**	**$ 169,415**	**$ -**	**$ (29,493)**	**$ 460,236**
Unrealized gain on risk management	**-**	**-**	**-**	**(1,625)**	**-**	**(1,625)**
Cost of sales	**(167,335)**	**(69,710)**	**(87,962)**	**-**	**27,839**	**(297,168)**
Operating and administrative	**(49,129)**	**(7,209)**	**(47,454)**	**(5,783)**	**1,654**	**(107,921)**
Accretion of asset retirement obligations	**(881)**	**(32)**	**(13)**	**-**	**-**	**(926)**
Depreciation, depletion and amortization	**(17,421)**	**(5,749)**	**(13,587)**	**(1,029)**	**-**	**(37,786)**
Income from equity investments	**130**	**48,910**	**506**	**-**	**-**	**49,546**
Other income (expense)	**69**	**-**	**544**	**275**	**-**	**888**
Foreign exchange gain	**-**	**-**	**-**	**(396)**	**-**	**(396)**
Interest expense	**-**	**-**	**-**	**(25,219)**	**-**	**(25,219)**
Income (loss) before income taxes	**$ 20,320**	**$ 31,637**	**$ 21,449**	**$ (33,777)**	**-**	**$ 39,629**
Net additions (reductions) to:						
Property, plant and equipment[1]	**5,914**	**646,838**	**59,702**	**3,380**	**-**	**$ 715,834**
Intangible assets	**1,106**	**(24)**	**3,004**	**(491)**	**-**	**$ 3,595**
Long-term investment and other assets	**161**	**(1,337)**	**4,950**	**1,394**	**-**	**$ 5,168**

Six months ended June 30, 2013 (unaudited)	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 541,731**	**$ 132,194**	**$ 492,313**	**-**	**$ (85,479)**	**$ 1,080,759**
Unrealized gain on risk management	**-**	**-**	**-**	**(8,679)**	**-**	**(8,679)**
Cost of sales	**(362,950)**	**(121,665)**	**(287,012)**	**-**	**82,080**	**(689,547)**
Operating and administrative	**(94,496)**	**(12,843)**	**(92,615)**	**(11,217)**	**3,399**	**(207,772)**
Accretion of asset retirement obligations	**(1,816)**	**(63)**	**(13)**	**-**	**-**	**(1,892)**
Depreciation, depletion and amortization	**(34,817)**	**(8,759)**	**(27,859)**	**(2,038)**	**-**	**(73,473)**
Income from equity investments	**296**	**64,724**	**1,144**	**-**	**-**	**66,164**
Other income (expense)	**144**	**-**	**916**	**(755)**	**-**	**305**
Foreign exchange gain (loss)	**-**	**-**	**-**	**4**	**-**	**4**
Interest expense	**-**	**-**	**-**	**(49,834)**	**-**	**(49,834)**
Income (loss) before income taxes	**$ 48,092**	**$ 53,588**	**$ 86,874**	**$ (72,519)**	**-**	**$ 116,035**
Net additions (reductions) to:						
Property, plant and equipment[1]	**$ 14,556**	**$ 718,540**	**$ 99,572**	**$ 2,859**	**-**	**$ 835,527**
Intangible assets	**$ 3,357**	**$ (98)**	**$ 2,887**	**$ (983)**	**-**	**$ 5,163**
Long-term investment and other assets	**$ (516)**	**$ 426**	**$ 4,839**	**$ (1,075)**	**-**	**$ 3,674**
As at June 30, 2013:						
Goodwill	**$ 161,401**	**-**	**$ 578,081**	**-**	**-**	**$ 739,482**
Segmented assets	**$ 2,035,809**	**$ 1,913,535**	**$ 2,569,297**	**$ 185,701**	**-**	**$ 6,704,342**

Three months ended June 30, 2012 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 172,869	$ 48,157	$ 34,971	-	$ (7,456)	$ 248,541
Unrealized loss on risk management	-	-	-	23,643	-	23,643
Cost of sales	(97,217)	(26,715)	(9,258)	-	6,359	(126,831)
Operating and administrative	(41,419)	(4,566)	(17,510)	(7,293)	1,097	(69,691)
Accretion of asset retirement obligations	(758)	(28)	18	-	-	(768)
Depreciation, depletion and amortization	(14,074)	(2,667)	(2,949)	(839)	-	(20,529)
Income from equity investments	129	(186)	(23)	-	-	(80)
Other income (expense)	-	-	-	(1,298)	-	(1,298)
Foreign exchange loss	-	-	-	(2,015)	-	(2,015)
Interest expense	-	-	-	(13,065)	-	(13,065)
Income (loss) before income taxes	$ 19,530	$ 13,995	$ 5,249	$ (867)	-	$ 37,907
Net additions (reductions) to:						
Property, plant and equipment[1]	107,189	93,132	(24,917)	959	-	$ 176,363
Intangible assets	(2,793)	791	19,121	128	-	$ 17,247
Long-term investment and other assets	5,987	(7,667)	(3,963)	2,499	-	$ (3,144)

Six months ended June 30, 2012 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 416,591	$ 107,573	$ 112,751	-	$ (27,881)	$ 609,034
Unrealized loss on risk management	-	-	-	24,800	-	24,800
Cost of sales	(253,593)	(63,521)	(44,770)	-	25,916	(335,968)
Operating and administrative	(84,193)	(9,643)	(36,364)	(15,105)	1,965	(143,340)
Accretion of asset retirement obligations	(1,516)	(56)	(11)	-	-	(1,583)
Depreciation, depletion and amortization	(27,874)	(5,210)	(7,002)	(1,726)	-	(41,812)
Income from equity investments	224	11,768	73	-	-	12,065
Other income (expense)	-	-	-	515	-	515
Foreign exchange gain (loss)	-	-	-	(2,149)	-	(2,149)
Interest expense	-	-	-	(25,827)	-	(25,827)
Income (loss) before income taxes	$ 49,639	$ 40,911	$ 24,677	$ (19,492)	-	$ 95,735
Net additions to:						
Property, plant and equipment[1]	$ 191,412	$ 151,325	$ (19,946)	$ 1,037	-	$ 323,828
Intangible assets	$ (1,893)	$ 788	$ 19,256	$ 144	-	$ 18,295
Long-term investment and other assets	$ 5,886	$ 28,301	$ (3,867)	$ 5,825	-	$ 36,145
As at June 30, 2012:						
Goodwill	$ 161,402	-	$ 119,721	-	-	$ 281,123
Segmented assets	$ 2,028,305	$ 880,416	$ 802,933	$ 140,440	-	$ 3,852,094

[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.*

Supplementary Quarterly Financial Information
(unaudited)

($ millions unless otherwise indicated)	**Q2-13**	Q1-13	Q4-12	Q3-12	Q2-12
FINANCIAL HIGHLIGHTS[1]					
Net Revenue[2]					
Gas	**87.8**	91.5	84.3	74.5	75.8
Power	**44.6**	30.6	24.5	28.7	21.3
Utilities	**82.5**	124.9	108.0	36.6	25.7
Corporate	**(1.4)**	(8.2)	(9.3)	6.7	22.3
Intersegment Elimination	**(1.7)**	(1.7)	0.1	(0.2)	(1.1)
	211.8	237.1	207.6	146.3	144.0
EBITDA[2]					
Gas	**38.7**	46.1	42.0	33.0	34.3
Power	**37.4**	25.0	20.0	24.8	16.7
Utilities	**35.0**	79.7	64.0	12.4	8.2
Corporate	**(5.6)**	(6.5)	(8.2)	(10.9)	(8.6)
	105.5	144.3	117.8	59.3	50.6
Operating Income (Loss)[2]					
Gas	**20.3**	27.8	26.3	17.7	19.5
Power	**31.6**	21.9	14.1	21.9	14.0
Utilities	**21.4**	65.4	50.4	5.5	5.2
Corporate	**(6.5)**	(7.5)	(9.1)	(11.7)	(9.4)
	66.8	107.6	81.7	33.4	29.3

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

(2) *Non-GAAP financial measure.*

Supplementary Quarterly Operating Information

(unaudited)

	Q2-13	Q1-13	Q4-12	Q3-12	Q2-12
OPERATING HIGHLIGHTS					
GAS					
E&T					
Extraction inlet gas processed (Mmcf/d)(1)	**953**	977	914	850	829
Extraction volumes (Bbls/d)(1)	**50,965**	46,520	40,122	40,061	34,547
Frac spread - realized ($/Bbl)(1)(2)	**20.80**	29.57	32.44	28.59	27.64
Frac spread - average spot price ($/Bbl)(1)(3)	**17.85**	27.23	24.73	22.75	26.85
FG&P					
Processing Throughput (gross Mmcf/d)(1)	**413**	403	377	362	351
Energy Services					
Average volumes transacted (GJ/d)(1)(4)	**328,777**	438,387	396,174	334,973	318,738
POWER					
Volume of power sold (GWh)(1)	**1,035**	866	856	843	802
Average price realized on sale of power ($/MWh)(1)(8)	**87.01**	73.25	72.71	73.34	58.54
Alberta Power Pool average spot price ($/MWh)(1)	**123.41**	65.28	78.71	78.09	40.03
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(5)	**5.3**	11.7	10.4	2.6	4.6
Natural gas deliveries - transportation (PJ)(5)	**1.4**	1.7	1.7	1.4	1.7
U.S. utilities					
Natural gas deliveries end use (Bcf)	**11.6**	28.8	23.3	2.6	-
Natural gas deliveries transportation (Bcf)	**9.8**	12.7	11.0	2.9	-
Service sites(6)	**546,906**	549,905	547,977	543,261	115,437
Degree day variance from normal - AUI (%)(7)	**3.0**	(4.8)	19.2	(53.6)	(2.9)
Degree day variance from normal - Heritage Gas (%)(7)	**(2.1)**	(2.1)	(6.3)	(38.8)	(9.7)
Degree day variance from normal - SEMCO Michigan (%)(7)	**16.4**	4.5	(2.6)	41.7	-
Degree day variance from normal - SEMCO Alaska (%)(7)	**12.8**	(5.3)	10.4	3.5	-

(1) Average for the period.

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

(3) 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 shrinkage gas and extraction premiums, divided by the respective frac exposed volumes for the period.

(4) Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

(5) Petajoule (PJ) is one million gigajoules (GJ).

(6) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and SEMCO Michigan and Alaska, including transportation and non-regulated business lines.

(7) Degree days relate to AUI, Heritage Gas and SEMCO service areas. A degree day 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 for its residential and small commercial customers due to a British Columbia Utilities Commission approved rate stabilization mechanism. For SEMCO degree days are 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 fifteen years for Michigan and during the prior ten years for Alaska.

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

Other Information

DEFINITIONS

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

ABOUT ALTAGAS

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

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