AltaGas

NEWS RELEASE
ALTAGAS LTD. REPORTS FIRST QUARTER RESULTS AND INCREASES DIVIDEND 8.5 PERCENT

Calgary, Alberta (April 30, 2015)

Highlights

- Increased dividend by $0.0125 per share per month ($1.92 per share annualized) beginning with the June 15, 2015 payment;
- $178 million in normalized EBITDA;
- $140 million in normalized funds from operations;
- $57 million in normalized net income;
- Strong operating results from Forrest Kerr and Volcano Creeek; and
- McLymont Creek nears completion.

AltaGas Ltd. ("AltaGas") (TSX:ALA) today reported first quarter normalized EBITDA of $178 million, compared to $179 million in the same period 2014. Normalized funds from operations were $140 million ($1.05 per share) for the first quarter 2015, compared to $132 million ($1.07 per share) in the same period 2014. Normalized net income was $57 million ($0.43 per share), compared to $74 million ($0.60 per share) in first quarter 2014.

"Throughout the quarter we faced one of the weakest energy environments we have ever seen, including the lowest power prices in Alberta since deregulation. Despite this, we still delivered on cash flow growth driven by our diverse infrastructure assets," said David Cornhill, Chairman and CEO of AltaGas. "Our Forrest Kerr and Volcano Creek hydroelectric facilities performed better than expected in the quarter and with the addition of McLymont Creek mid-year we expect significant growth in cash flow in 2015 and 2016. Our dividend increase underscores our commitment to creating shareholder value."

For first quarter 2015, cash flow was driven by higher contributions in the Power segment from Blythe and the addition of Forrest Kerr and Volcano Creek. Cash flow was also driven by seasonally strong results and growth at the utilities, and higher throughput at some of our key gas processing facilities including Gordondale and Blair Creek. Cash flow also benefitted from favourable foreign exchange. Cash flow was partially offset by the low spot power prices in Alberta and significantly lower frac spread and frac exposed volumes compared to first quarter 2014.

Earnings were impacted by higher depreciation and interest expense primarily as a result of bringing Forrest Kerr and Volcano Creek into service in the second half of 2014, as well as a higher effective tax rate in the quarter as a result of a higher proportion of US earnings subject to a higher tax rate.

AltaGas maintains financial strength and flexibility, an investment grade credit rating, and ready access to capital markets. At the end of the first quarter, AltaGas had $341 million in cash and short-term investments and $1.8 billion available on its credit facilities.

On a GAAP basis, net income applicable to common shares was $66 million ($0.49 per share) in first quarter 2015, compared to $40 million ($0.33 per share) for same period 2014. In first quarter 2015, net income applicable to common shares was normalized for after-tax amounts related to unrealized gains on risk management contracts and development costs incurred for the energy export projects. In first quarter 2014, net income applicable to common shares was normalized for aftertax amounts related to unrealized losses on risk management contracts and development costs incurred for the energy export projects as well as costs incurred for early redemption of MTN's, provision on assets and gains on asset dispositions.

Project Updates

McLymont Creek

At the 66-MW McLymont Creek project, construction of the seven kilometre intake access road is complete and intake construction is underway. Excavation of the McLymont power tunnel has been completed. Construction of the powerhouse and installation of the turbine generators are complete. Early commissioning has commenced with backfeed scheduled for second quarter 2015. The project is expected to be in service mid-2015.

Townsend Gas Processing Facility

All permit applications have been submitted and detailed engineering is nearing completion for the 198 Mmcf/d shallow-cut gas processing Townsend facility. Long-lead equipment orders including compressors, refrigeration packages and major pipe for project pipelines have been released. Site clearing has been completed and preliminary civil construction activities have commenced. Full scale construction is expected to commence in third quarter 2015 subject to receipt of regulatory approvals, and is expected to be in service by mid-2016, in advance of Painted Pony's production requirements.

LPG Export Business

AltaGas has also significantly advanced its liquefied petroleum gas (LPG) export initiatives. The Ferndale LPG export facility located in the State of Washington and owned by Petrogas has been modified to export both propane and butane. The number of shipments from the Ferndale facility is expected to ramp up over the next several years to approximately 30,000 Bbls/d.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- The Board of Directors approved a dividend of $0.16 per common share. The dividend will be paid on June 15, 2015, to common shareholders of record on May 25, 2015. The exdividend date is May 21, 2015. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing April 1, 2015 and ending June 30, 2015, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on June 30, 2015 to shareholders of record on June 16, 2015. The exdividend date is June 12, 2015;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing April 1, 2015 and ending June 30, 2015, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on June 30, 2015 to shareholders of record on June 16, 2015. The exdividend date is June 12, 2015;
- The Board of Directors also approved a dividend of $0.3125 per share for the period commencing April 1, 2015, and ending June 30, 2015, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on June 30, 2015 to shareholders of record on June 16, 2015. The exdividend date is June 12, 2015; and
- The Board of Directors also approved a dividend of $0.296875 per share for the period commencing April 1, 2015, and ending June 30, 2015, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on June 30, 2015 to shareholders of record on June 16, 2015. The ex-dividend date is June 12, 2015.

CONSOLIDATED FINANCIAL REVIEW

(unaudited) *($ millions)*	Three months ended March 31 **2015**	 2014
Revenue	**744**	824
Net revenue[1]	**307**	297
Normalized operating income[1]	**125**	137
Normalized EBITDA[1]	**178**	179
Net income applicable to common shares	**66**	40
Normalized net income[1]	**57**	74
Total assets	**8,619**	7,377
Total long-term liabilities	**3,954**	4,044
Net additions to property, plant and equipment	**110**	154
Dividends declared[2]	**59**	47
Cash flows		
Normalized funds from operations[1]	**140**	132

($ per share, except shares outstanding)	Three months ended March 31 **2015**	 2014
Normalized EBITDA[1]	**1.33**	1.46
Net income - basic	**0.49**	0.33
Net income - diluted	**0.49**	0.32
Normalized net income[1]	**0.43**	0.60
Dividends declared[2]	**0.44**	0.38
Cash flows		
Normalized funds from operations[1]	**1.05**	1.07
Shares outstanding - basic (millions)		
During the period[3]	**134**	123
End of period	**135**	123

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

(2) Dividends declared per common share per month $0.1275 beginning July 31, 2013, and $0.1475 beginning May 26, 2014

(3) Weighted average.

CONFERENCE CALL AND WEBCAST DETAILS:

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

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

Shortly after the conclusion of the call, a replay will be available by dialing (905) 694-9451 or 1-800-408-3053. The passcode is 1360547. The replay expires at midnight (Eastern) on May 7, 2015.

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and unaudited condensed interim Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the three months ended March 31, 2015, compared to the three months ended March 31, 2014. This MD&A dated April 30, 2015, 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 months ended March 31, 2015, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2014.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or any affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "2015 Outlook" and "Growth Capital".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in AltaGas' public disclosure documents.

Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward looking statements except as required by law. The forward looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other than for which it is disclosed herein.

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

ALTAGAS ORGANIZATION

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by AltaGas, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc.

FIRST QUARTER HIGHLIGHTS (1)

- Normalized funds from operations was $140 million, compared to $132 million in first quarter 2014;
- Normalized EBITDA was $178 million, compared to $179 million in first quarter 2014;
- Normalized operating income was $125 million, compared to $137 million in first quarter 2014;
- Normalized net income per share was $0.43, compared to $0.60 in first quarter 2014;
- Net debt was $3.0 billion as at March 31, 2015, compared to $3.2 billion as at March 31, 2014, and $2.9 billion as at December 31, 2014;
- Cash on hand and short-term investments as at March 31, 2015 was $341 million and $1.8 billion was available on credit facilities;
- Debt-to-total capitalization ratio was 45 percent as at March 31, 2015, compared to 53 percent as at March 31, 2014, and 45 percent as at December 31, 2014;
- Closed acquisition on January 8, 2015 of three gas-fired power assets in the U.S. with a total capacity of 164 MW for US$27 million before adjustments for working capital; and
- On April 14, 2015, issued US$125 million senior unsecured medium-term notes (MTNs). The notes carry a floating coupon rate of three month LIBOR plus 0.85 percent and mature on April 17, 2017.

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

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(3) *Weighted average.*

Three Months Ended March 31

Normalized net income was $57 million ($0.43 per share) for first quarter 2015, compared to $74 million ($0.60 per share) for same quarter 2014. First quarter 2015 earnings benefitted from favourable exchange rates and improved results for Blythe and Energy Services and stronger throughput at key gas processing facilities. The overall decrease in normalized net income reflects weak natural gas liquids (NGL) prices and lower frac exposed volumes, lower earnings from Petrogas Energy Corp. (Petrogas), and lower Alberta power prices and volumes as well as higher interest expense and depreciation.

The decrease in NGL and Alberta power prices was partially mitigated by AltaGas' hedging strategy. Due to seasonality, the Forrest Kerr and Volcano Creek run-of-river hydro facilities, placed into service in 2014, reduced first quarter 2015 normalized net income due to higher interest and depreciation expense, which is recorded on a straight-line basis whereas the power generation at the facilities occurs substantially from mid-second quarter through the fourth quarter.

Normalized EBITDA for first quarter 2015 of $178 million was roughly flat to first quarter 2014. The contribution from Forrest Kerr and Volcano Creek, favourable exchange rates, improved results for Blythe and Energy Services and stronger throughput at key gas processing facilities were offset by the commodity price and volume impacts and lower Petrogas earnings as noted above.

Normalized funds from operations for first quarter 2015 was $140 million ($1.05 per share), compared to $132 million ($1.07 per share) for same quarter 2014. The increase in normalized funds from operations reflects strong performance from our infrastructure assets, partially offset by higher interest and current income taxes.

Normalized operating income increased as a result of a weaker Canadian dollar, stronger performance from Power and key gas processing assets. However, weaker commodity prices, lower frac exposed volumes, lower contribution from Petrogas and higher depreciation primarily due to Forrest Kerr and Volcano Creek resulted in an overall decline from $137 million in first quarter 2014 to $125 million in first quarter 2015.

Net income applicable to common shares for first quarter 2015 was $66 million ($0.49 per share), compared to $40 million ($0.33 per share) for same quarter 2014. Net income applicable to common shares for first quarter 2015 was normalized for after-tax amounts related to unrealized gains on risk management contracts and development costs incurred for the energy export projects. In first quarter 2014, net income applicable to common shares was normalized for after-tax amounts related to unrealized losses on risk management contracts and development costs incurred for the energy export projects as well as costs incurred for early redemption of MTN's, provision on assets, and gains on asset dispositions.

Operating and administrative expense for first quarter 2015 was $117 million, compared to $114 million for same quarter 2014. The increase was primarily due to the new assets brought into service and higher compensation costs. Depreciation, depletion and amortization expense for first quarter 2015 was $50 million, compared to $41 million for same quarter 2014, mainly due to the new assets placed into service in second half 2014.

Interest expense for first quarter 2015 was $30 million, compared to $25 million for same quarter 2014. Interest expense increased due lower capitalized interest, primarily due to Forrest Kerr and Volcano Creek entering service in second half 2014.

AltaGas recorded income tax expense of $30 million for first quarter 2015, compared to $17 million in same quarter 2014. Income tax expense increased primarily due to higher net income, due primarily to provisions on long-lived assets recorded in first quarter 2014, and proportionately higher U.S. earnings, which bear higher corporate income tax rates.

2015 OUTLOOK

AltaGas' diversified portfolio of energy infrastructure assets is well positioned to weather commodity and economic cycles. Two-thirds of AltaGas' business consists of regulated utilities and highly contracted power generation. The other third is AltaGas' Gas business which is also highly contracted with take-or-pay and cost-of-service contracts.

In 2015, the Power and Utilities segments are expected to report higher earnings and the Gas segment is expected to remain nearly flat to 2014 after adjusting for the $12 million pre-tax impact, including lost revenue, for the turnarounds at the Harmattan Complex (Harmattan) and at the Younger Extraction Plant (Younger) and assuming frac spreads recover in the latter half of 2015.

AltaGas expects to deliver earnings and cash flow growth in 2015 compared to 2014 as a result of the contribution from the Northwest Projects, growth in rate base and customers at the utilities, other growth projects coming into service, and the stronger US dollar. These increases are expected to be impacted by lower contributions from Alberta power assets and frac exposed volumes if the weak commodity price environment persists for all of 2015. Petrogas' EBITDA is expected to increase as they continue to grow their fee-for-service and margin-based businesses. Net earnings reported from Petrogas are expected to be lower as a result of increased amortization and interest expense related to the recent expansions of Petrogas' assets. AltaGas expects to report higher financing costs and increased depreciation related to new assets in service, and higher income taxes.

Based on the current price environment, AltaGas expects that over 90 percent of overall EBITDA in 2015 will be driven by its portfolio of long-life assets underpinned by long-term, take-or-pay and cost-of-service contracts and regulated earnings.

Management estimates an average of 5,400 Bbls/d will be exposed to frac spread in 2015. For 2015, AltaGas has hedged approximately 55 percent of the estimated volumes exposed to frac spread at an average price of approximately $27/Bbl before deducting extraction premiums.

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

While the current pace of development in the Montney has been strong, if the significantly decreased oil and regional NGL prices experienced in late 2014 and early 2015 are sustained, projects under development could be delayed. To the extent there are delays, AltaGas has the potential to redeploy its growth capital into additional attractive investment opportunities across its diversified Power and Utility businesses.

In the Power segment, earnings are expected to be driven by the full year contribution from Forrest Kerr and Volcano Creek, the partial year contribution from McLymont Creek, optimization of power assets including increased utilization at Sundance, and higher contribution from the U.S. power business due to continued growth and development opportunities, as well as favourable foreign exchange. The earnings and cash flows from Forrest Kerr and Volcano Creek are expected to be seasonally stronger beginning in the second quarter through the fourth quarter and seasonally weaker in the first quarter based on normal water flow patterns.

AltaGas expects to continue its Alberta power hedging strategy in order to balance its market and operational risks. AltaGas has hedged approximately one-third of volumes exposed to Alberta power prices for second quarter 2015 at an average price of approximately $45/MWh. Overall for 2015, AltaGas has hedged approximately one-third of volumes exposed to Alberta power prices at an average price of approximately $54/MWh. AltaGas expects to continue to hedge its exposure to Alberta Power prices throughout 2015 at prices lower than 2014 hedged prices if current forward curves persist throughout 2015.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong first and fourth quarters due to the winter heating season. The utilities are expected to report increased earnings in 2015 driven by increased customer and rate base growth. Earnings at all of the utilities except Pacific Northern Gas Ltd. (PNG) are affected by the weather in their franchise areas, with colder weather generally benefitting earnings. If the weather varies from the previous year, earnings at the utilities would be affected.

If the US dollar continues to appreciate, the earnings from the U.S. utilities and power assets will benefit accordingly in 2015. Some of this benefit is offset by interest on US dollar-denominated debt.

In second quarter 2015 we expect our normal seasonality, where earnings are typically lower as a result of the weaker quarter in the utilities, and the turnarounds at Harmattan and Younger, along with lower frac and power prices, to result in lower normalized operating income compared with first quarter 2015. These decreases are expected to be partially offset by the contribution from the Northwest Projects as water flow ramps up.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $550 million to $650 million for 2015. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through internally-generated cash flow, the Dividend Reinvestment and Optional Share Purchase Plan (DRIP), and available credit facilities. As at March 31, 2015, the Corporation had approximately $1.8 billion available on its credit facilities as well as cash on hand and short-term investments of $341 million.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwestern British Columbia: 195 MW Forrest Kerr, 16-MW Volcano Creek and 66-MW McLymont Creek. The 277-MW Northwest Projects are contracted with 60-year EPAs with BC Hydro fully indexed to the CPI, as well as Impact Benefit Agreements with the Tahltan First Nation. The Forrest Kerr and Volcano Creek projects both entered service in second half 2014.

McLymont Creek

At the 66-MW McLymont Creek project, construction of the seven kilometre intake access road is complete and intake construction is underway. Excavation of the McLymont power tunnel has been completed. Construction of the powerhouse and installation of the turbines are complete. Early commissioning has commenced with backfeed scheduled for second quarter 2015. The project is expected to be in service in mid-2015.

Townsend Gas Processing Facility

On August 19, 2014 AltaGas and Painted Pony entered into a 15-year strategic alliance for the development of processing infrastructure and marketing services for natural gas and NGL. In the first phase of the strategic alliance, a 198 Mmcf/d shallow-cut gas processing facility, known as the Townsend Facility, will be constructed and operated by AltaGas. Painted Pony has reserved all of the firm capacity. The Townsend Facility will be located approximately 100 kilometers north of Fort St. John and 20 kilometers southeast of AltaGas' Blair Creek facility and is estimated to cost $325 to $350 million. All permit applications have been submitted and detailed engineering is nearing completion. Long-lead equipment orders including compressors, refrigeration packages and major pipe for project pipelines have been released. Site clearing has been completed and preliminary civil construction activites have commenced. Full scale construction is expected to commence in third quarter 2015 with the receipt of regulatory approvals, and the facility is expected to be in service by mid-2016, in advance of Painted Pony's production requirements.

AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP)

LPG Export Business

The LPG export Ferndale facility located in the State of Washington and owned by a U.S. subsidiary of Petrogas has been modified to export both propane and butane. The facility is expected to increase the number of LPG shipments resulting in a ramp up over the next several years to approximately 30,000 Bbls/d.

Harmattan Cogeneration III

AltaGas is expanding its cogeneration fleet at Harmattan to 45 MW. In first quarter 2014, AltaGas began engineering and procured the combustion turbine for the new 15 MW Cogeneration III to meet the increased power demand at Harmattan and increase sales to the Alberta power market. Construction and installation of the power generation equipment are complete and the unit successfully supplied full load test power to the grid in March 2015. Cogeneration III is on budget with a total project cost of approximately $40 million. Final tie in of the steam system will be completed during the Harmattan turnaround in May and the unit will then be complete in COGEN mode. The project is expected to be in commercial service in third quarter 2015.

U.S. Power Assets Acquisition

On January 8, 2015 AltaGas completed the acquisition of three gas-fired power assets in the western U.S. with a total generation capacity of 164 MW for US$27 million before adjustments for working capital. All three assets are currently contracted under PPAs with local creditworthy utilities and generate stable cash flows. The acquisition is consistent with AltaGas' strategy of capitalizing on the demand for clean energy sources such as natural gas; growing and diversifying the power portfolio by increasing AltaGas' presence in the California and Colorado power markets; providing low-risk, fully contracted cash flows; and providing the potential for future organic growth opportunities via repowering and expansion of the sites.

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

($ millions)		Three months ended March 31 2015		2014
Net revenue	**$**	**307**	$	297
Add (deduct):				
Other (income) expenses		**(2)**		(10)
(Income) loss from equity investments		**6**		(17)
Cost of sales		**433**		554
Revenue (GAAP financial measure)	**$**	**744**	$	824

Management believes that net revenue, which is revenue plus other income (expenses) plus income (loss) 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

($ millions)		Three months ended March 31 2015		2014
Normalized operating income	**$**	**125**	$	137
Add (deduct):				
Provision on long-lived assets		**-**		(49)
Costs associated with early redemption of MTNs		**-**		(2)
Gain on asset dispositions		**-**		11
Joint venture development costs		**(1)**		-
Operating income		**124**		97
Add (deduct):				
Unrealized gain (loss) on risk management contracts		**13**		(6)
Interest expense		**(30)**		(25)
Foreign exchange gain		**1**		1
Income tax expense		**(30)**		(17)
Net income applicable to non-controlling interests		**(2)**		(2)
Preferred share dividends		**(10)**		(7)
Net income applicable to common shares (GAAP financial measure)	**$**	**66**	$	40

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

Normalized operating income represents operating income adjusted for non-operating related expenses such as provision taken on long-lived assets, costs associated with early redemption of MTNs and gain on asset dispositions. Normalized operating income also includes an adjustment for the project development costs incurred by AIJVLP.

Normalized EBITDA	Three months ended March 31	
($ millions)	**2015**	2014
Normalized EBITDA	**$ 178**	$ 179
Add (deduct):		
Gain on asset dispositions	**-**	11
Joint venture development costs	**(1)**	-
Costs associated with early redemption of MTNs	**-**	(2)
EBITDA	**177**	188
Add (deduct):		
Unrealized gain (loss) on risk management contracts	**13**	(6)
Depreciation, depletion and amortization	**(50)**	(41)
Provision on long-lived assets	**-**	(49)
Accretion of asset retirement obligations	**(3)**	(1)
Interest expense	**(30)**	(25)
Foreign exchange gain	**1**	1
Income tax expense	**(30)**	(17)
Net income applicable to non-controlling interests	**(2)**	(2)
Preferred share dividends	**(10)**	(7)
Net income applicable to common shares (GAAP financial measure)	**$ 66**	$ 40

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

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as costs associated with early redemption of MTNs and gain on asset dispositions. Normalized EBITDA also includes an adjustment for the project development costs incurred by AIJVLP.

Normalized Net Income		Three months ended March 31
($ millions)	**2015**	2014
Normalized net income	**$ 57**	$ 74
Add (deduct) after-tax:		
Unrealized gain (loss) on risk management contracts	**10**	(4)
Gain on asset dispositions	**-**	9
Provision on long-lived assets	**-**	(37)
Joint venture development costs	**(1)**	-
Costs associated with early redemption of MTNs	**-**	(2)
Net income applicable to common shares (GAAP financial measure)	**$ 66**	$ 40

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as gain on asset dispositions, provision taken on long-lived assets and costs associated with early redemption of MTNs. Normalized net income also includes an adjustment for the project development costs incurred by AIJVLP.

Normalized Funds from Operations		Three months ended March 31
($ millions)	**2015**	2014
Normalized funds from operations	**$ 140**	$ 132
Funds from operations	**140**	132
Add (deduct):		
Net change in operating assets and liabilities	**63**	42
Cash from operations (GAAP financial measure)	**$ 203**	$ 174

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in operating assets and liabilities in the period and non-operating related one-time expenses such as transaction costs related to acquisitions. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities, expenditures incurred to settle asset retirement obligations and non-operating related expenses.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized Operating Income (1) *($ millions)*	Three months ended March 31 **2015**	 2014
Gas	**$ 31**	$ 48
Power	**15**	16
Utilities	**86**	81
Sub-total: Operating Segments	**132**	145
Corporate	**(7)**	(8)
	$ 125	$ 137

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

GAS

OPERATING STATISTICS	Three months ended March 31 **2015**	 2014
Total inlet gas processed (Mmcf/d)(1)	**1,498**	1,573
Extraction ethane volumes (Bbls/d)(1)	**37,736**	34,257
Extraction NGL volumes (Bbls/d)(1)	**35,557**	37,758
Total extraction volumes (Bbls/d)(1) (2)	**73,293**	72,015
Frac spread - realized ($/Bbl)(1) (3)	**11.43**	25.84
Frac spread - average spot price ($/Bbl)(1) (4)	**3.72**	35.76

(1) *Average for the period.*

(2) *Includes Harmattan NGLs processed on behalf of customers.*

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

(4) *Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.*

In first quarter 2015, total inlet gas processed decreased by 75 Mmcf/d. The decrease was primarily driven by lower Harmattan volumes, the sale of Ante Creek in first quarter 2014, natural declines and shut-ins, partially offset by higher volumes at the Gordondale and Blair Creek facilities.

In first quarter 2015, average ethane volumes produced increased by 3,479 Bbls/d and NGL volumes decreased by 2,201 Bbls/d, compared to same quarter 2014. The increase in average ethane volumes is primarily due to higher Harmattan co-stream ethane recoveries, higher Younger and JEEP ethane volumes, partially offset by lower PEEP ethane volumes. NGL volumes decreased due to the reinjections of certain NGLs due to weak prices.

Three Months Ended March 31

The Gas segment reported normalized operating income of $31 million in first quarter 2015, compared to $48 million in same quarter 2014. The decrease reflects the substantially weaker frac spreads in first quarter 2015, which were partially mitigated by AltaGas' hedging strategy. Extraction revenues were also adversely impacted by reduced frac exposed volumes resulting from lower frac spreads. Earnings from Petrogas were lower in first quarter 2015 compared to same quarter 2014. Partially offsetting these decreases were higher throughput at key gas processing facilities and improved results from Energy Services as a result of higher costs to fulfill delivery commitments from operational curtailments resulting from extremely cold weather in eastern North America in first quarter 2014.

The Gas segment reported operating income of $30 million in first quarter 2015, compared to $20 million in same quarter 2014. First quarter 2014 included the impact of a $38 million pre-tax provision taken on the Ethylene Delivery System (EDS) and the Joffre Feedstock Pipeline (JFP) transmission pipeline assets and an $11 million pre-tax gain on sale of assets.

During first quarter 2015, AltaGas hedged approximately 45 percent of frac exposed production at an average price of $27/Bbl. During first quarter 2014 AltaGas hedged approximately 70 percent of frac exposed production at an average price of $27/Bbl. The average indicative spot NGL frac spread for first quarter 2015 was approximately $4/Bbl compared to approximately $36/Bbl in same quarter 2014. All prices are before deducting extraction premiums.

POWER

OPERATING STATISTICS	Three months ended March 31	
	2015	2014
Volume of power sold (GWh [1])	**1,449**	1,181
Average price realized on the sale of power ($/MWh) [2]	**54.62**	69.36
Alberta Power Pool average spot price ($/MWh)	**29.02**	60.60

(1) *Volume of power sold under purchase agreement based on target availability.*

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

During first quarter 2015, volume of power sold increased by 268 GWh compared to same quarter 2014. Volumes sold during first quarter 2015 comprised of 1,075 GWh conventional power generation and 374 GWh renewable power generation, compared to 1,059 GWh conventional power generation and 122 GWh renewable power generation in same quarter 2014. Power generation at Forrest Kerr was higher than expected due to favourable waterflow and strong operational performance of the asset.

Three Months Ended March 31

The Power segment reported normalized operating income of $15 million for first quarter 2015, compared to $16 million for same quarter 2014. Despite the record low Alberta Power Pool average spot price since deregulation, normalized operating income was nearly flat to first quarter 2014 due to a higher contribution from Blythe, favourable exchange rates, and lower gas costs at the gas-fired plants. Power generation at Forrest Kerr was higher than expected; however, due to normal seasonality, Forrest Kerr and Volcano Creek contributed negatively to normalized operating income in first quarter 2015 as depreciation expense is recognized on a straight-line basis whereas the power generation occurs substantially from mid-second quarter through the fourth quarter.

Operating income in the Power segment was $15 million in first quarter 2015, compared to $5 million in same quarter 2014. First quarter 2014 operating income included an $11 million pre-tax provision related to certain hydro power assets under development.

In first quarter 2015, AltaGas was 54 percent hedged in Alberta at an average price of $58/MWh. In first quarter 2014, AltaGas was 59 percent hedged at an average price of $65/MWh.

UTILITIES

OPERATING STATISTICS

	Three months ended March 31 2015	2014
Canadian utilities		
Natural gas deliveries - end-use (PJ)[1]	**13.0**	12.8
Natural gas deliveries - transportation (PJ)[1]	**1.9**	1.9
U.S. utilities		
Natural gas deliveries - end-use (Bcf)[1]	**32.1**	32.5
Natural gas deliveries - transportation (Bcf)[1]	**13.7**	12.4
Service sites [2]	**564,173**	557,062
Degree day variance from normal - AUI (%) [3]	**(11.3)**	5.5
Degree day variance from normal - Heritage Gas (%) [3]	**15.7**	3.9
Degree day variance from normal - SEMCO Gas (%) [4]	**16.4**	24.1
Degree day variance from normal - ENSTAR (%) [4]	**(8.0)**	(8.3)

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

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

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

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

Three Months Ended March 31

The Utilities segment reported operating income of $86 million in first quarter 2015, compared to $81 million in same quarter 2014. The increase was due to favourable foreign exchange rates, colder weather in Nova Scotia, and continued rate base and customer growth at the utilities, partially offset by warmer weather in Michigan and Alberta and higher operating costs in first quarter 2015 compared to first quarter 2014.

CORPORATE

Three Months Ended March 31

In the Corporate segment, normalized operating loss for first quarter 2015 was $7 million, compared to $8 million in same quarter 2014. Lower administrative expenses were partially offset by higher depreciation expense on Corporate IT and facility projects placed into service in 2014. Operating loss in the Corporate segment was $6 million for first quarter 2015, compared to $10 million for same quarter 2014. First quarter 2014 included $2 million of pre-tax costs associated with an early redemption of MTN's.

INVESTED CAPITAL

During first quarter 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $131 million, compared to $121 million in same quarter 2014. The net invested capital was $131 million for the three months ended March 31, 2015, compared to $94 million in same quarter 2014.

Invested Capital - Investment Type — **Three months ended March 31, 2015**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 22**	**$ 65**	**$ 23**	**-**	**$ 110**
Intangible assets	**-**	**9**	**-**	**6**	**15**
Long-term investments	**6**	**-**	**-**	**-**	**6**
Invested capital	**28**	**74**	**23**	**6**	**131**
Disposals:					
Property, plant and equipment	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**$ 28**	**$ 74**	**$ 23**	**$ 6**	**$ 131**

Invested Capital - Investment Type — Three months ended March 31, 2014

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 13	$ 80	$ 20	$ 2	$ 115
Intangible assets	-	-	-	3	3
Long-term investments	3	-	-	-	3
	16	80	20	5	121
Disposals:					
Property, plant and equipment	(27)	-	-	-	(27)
Net Invested capital	$ (11)	$ 80	$ 20	$ 5	$ 94

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 first quarter 2015 the Corporation had positions in the following types of derivatives, which are also disclosed in the unaudited Consolidated Financial Statements:

Commodity Forward Contracts

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

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

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

Commodity Swap Contracts

Power hedges:

AltaGas executes fixed for floating power price swaps to manage its power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power segment results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.00/MWh to $845.20/MWh in first quarter 2015 and $9.89/MWh to $886.31/MWh in first quarter 2014. The average Alberta spot price was $29.02/MWh in first quarter 2015 (first quarter 2014 - $60.60/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 was $54.62/MWh in first quarter 2015 (first quarter 2014 - $69.36/MWh). Overall for 2015, AltaGas has hedged approximately one-third of volumes exposed to Alberta power prices at an average price of $54/MWh.

NGL frac spread hedges

The Corporation executes fixed for floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During first quarter 2015, the Corporation hedged an average of 3,000 Bbls/d at an average price of approximately $27/Bbl. The average indicative spot NGL frac spread for first quarter 2015 was an estimated $3.72/Bbl (first quarter 2014 – $35.76/Bbl). The average NGL frac spread realized by AltaGas in first quarter 2015 was $11.43/Bbl (first quarter 2014 - $25.84/Bbl). Management estimates an average of approximately 5,400 Bbls/d will be exposed to frac spread in 2015. For 2015, approximately 55 percent of the estimated volumes exposed to frac spread have been hedged at an average price of approximately $27/Bbl prior to deducting extraction premiums.

Interest Rate Forward Contracts

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. As at March 31, 2015, the Corporation had no interest rate swaps outstanding. At March 31, 2015, the Corporation had fixed the interest rate on 86 percent of its debt including MTNs (March 31, 2014 - 74 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. Foreign exchange gains and losses on long-term debt denominated in US dollars are unrealized and can only be realized when the long-term debt matures or is settled.

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

LIQUIDITY

Cash Flows

($ millions)	Three months ended March 31 2015	2014
Cash from operations	**$ 203**	$ 174
Investing activities	**(161)**	(90)
Financing activities	**(126)**	(52)
Effect of exchange rate	**4**	2
Change in cash	**$ (80)**	$ 34

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $203 million in first quarter 2015, compared to $174 million in first quarter 2014. The increase in cash from operations reflects stronger cash flows from our infrastructure assets and favourable foreign exchange, partially offset by lower cash flows from our interest in the Sundance PPA as well as higher interest and current income taxes. Operating cash flows related to inventory were higher in first quarter 2015 compared with same quarter 2014 as the normal natural gas inventory draw-down for the utilities during the winter heating season was partially replenished at lower prices in the declining commodity price environment. Operating cash flows related to regulatory assets (current) were higher due to net collection of gas cost regulatory deferrals in first quarter 2015 compared with a net accumulation of gas cost regulatory deferrals in same quarter 2014 due to extreme cold weather in Michigan. Operating cash flows related to accounts payable were lower in first quarter 2015 compared with same quarter 2014 due to timing of payment runs, which resulted in higher payments processed in first quarter 2015.

Working Capital

As at March 31 ($ millions except current ratio)	2015	2014
Current assets	**$ 917**	$ 620
Current liabilities	**940**	438
Working capital	**(23)**	182
Current ratio	**1.0**	1.4

Working capital was in a deficit position of $23 million as at March 31, 2015, compared to working capital of $182 million as at March 31, 2014. The working capital ratio was 1.0 at the end of first quarter 2015, compared to 1.4 at the end of same quarter 2014. The working capital ratio decreased due to a higher current portion of long-term debt as at March 31, 2015, compared to the balance as at March 31, 2014, due to the scheduled timing of MTN maturities that will be refinanced in normal course, including the US$125 million MTN issuance on April 14, 2015, partially offset by higher cash and cash equivalents and short-term investments derived from the August 2014 common equity issuance.

Investing Activities

Cash used for investing activities in first quarter 2015 was $161 million compared to $90 million in same quarter 2014. Investing activities in first quarter 2015 comprised expenditures of $115 million for property, plant and equipment, and $9 million for intangible assets. Investing activities in first quarter 2014 comprised $117 million for acquisition of property, plant and equipment and $4 million for intangible assets, partially offset by proceeds of $27 million received on disposition of assets. Investing activities in first quarter 2015 included $32 million for the U.S. power assets acquisition.

Financing Activities

Cash used for financing activities in first quarter was $126 million, compared to cash used of $52 million in same quarter 2014. Financing activities in first quarter 2015 were primarily comprised of repayments of $4 million of long-term debt and $76 million of short-term debt. Financing activities in first quarter 2014 included repayment of $578 million of long-term debt and $78 million of short-term debt, and issuance of $641 million of long-term debt. In first quarter 2015, net proceeds from the DRIP program and the exercise of stock options contributed $25 million, compared to $21 million in same quarter 2014. Total dividends paid in first quarter 2015 were $70 million, compared to $55 million in same quarter 2014. The increase was due to higher common and preferred shares outstanding and the dividend increase declared in 2014.

CAPITAL RESOURCES

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

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 March 31, 2015, AltaGas had $2.8 billion of MTNs outstanding, PNG debenture notes of $57 million, SEMCO Energy, Inc. (SEMCO) long-term debt of $482 million and $127 million drawn from bank credit facilities. As at March 31, 2015, AltaGas' current portion of long-term debt was $487 million.

AltaGas' earnings interest coverage for the rolling twelve months ended March 31, 2015 was 2.2 times.

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

($ millions)		**March 31, 2015**		December 31, 2014
Debt				
Short-term debt	**$**	**2**	$	72
Current portion of long-term debt		**487**		214
Long-term debt		**2,855**		3,050
Less: cash and cash equivalent		**(291)**		(371)
Less: short-term investments		**(50)**		(50)
Net debt		**3,003**		2,915
Shareholders' equity		**3,690**		3,541
Non-controlling interests		**34**		33
Total capitalization	**$**	**6,727**	$	6,489
Debt-to-total capitalization ratio (%)		**45**		45

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The following table summarizes the Corporation's debt covenants for all credit facilities as at March 31, 2015:

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

On August 23, 2013, a $4 billion base shelf prospectus valid for 25 months was filed. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance. As at March 31, 2015, $2.0 billion remains available on the base shelf prospectus.

Credit Facilities *($ millions)*	Borrowing capacity	**Drawn at March 31 2015**	Drawn at December 31 2014
Demand operating facilities	$ 70	**$ 4**	$ 4
Extendible revolving letter of credit facility	150	**101**	113
PNG operating facility	25	**6**	14
Bilateral letter of credit facilities	140	**15**	13
AltaGas Ltd. revolving credit facility (1)	1,400	**-**	-
SEMCO Energy US$ unsecured credit facility (1) (2)	150	**1**	38
	$ 1,935	**$ 127**	$ 182

(1) *Amount drawn at March 31, 2015 converted at March 2015 month-end rate of 1 US dollar = 1.2683 Canadian dollar (Amount drawn at December 31, 2014 converted at December 2014 month-end rate of 1 US dollar = 1.1601 Canadian dollar).*

(2) *Borrowing capacity assumed at par.*

SHARE INFORMATION

As at March 31, 2015, AltaGas had 135 million common shares, 8 million series A Preferred Shares, 8 million series C US$ Preferred Shares, 8 million series E Preferred Shares and 8 million series G Preferred Shares outstanding with a combined market capitalization of approximately $6.5 billion based on a closing trading price on March 31, 2015 of $42.26 per common share, $20.43 per series A Preferred Share, $24.48 per series C US$ Preferred Share, $25.82 per series E Preferred Share and $25.21 per series G Preferred Share.

As at March 31, 2015, there were 5 million share options outstanding and 3 million share options exercisable under the terms of the share option plan.

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, capital expenditures, and debt repayment requirements of AltaGas.

On 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 2013 dividend.

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

The following table summarizes AltaGas' dividend declaration history:

Dividends
Years ended December 31

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

Series A Preferred Share Dividends
Years ended December 31

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

Series C Preferred Share Dividends
Years ended December 31

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

Series E Preferred Share Dividends
Years ended December 31

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

Series G Preferred Share Dividends
Years ended December 31

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

SUBSEQUENT EVENTS

On April 14, 2015, AltaGas issued US$125 million of senior unsecured MTNs. The notes carry a floating coupon rate of three months LIBOR plus 0.85 percent and mature on April 17, 2017.

SIGNIFICANT ACCOUNTING POLICIES

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

CRITICAL ACCOUNTING ESTIMATES

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

AltaGas' critical accounting estimates continue to be financial instruments, depreciation, depletion and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessment, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities. For a full discussion of these accounting estimates, refer to the MD&A in AltaGas' 2014 Financial Report and the notes to the unaudited interim Consolidated Financial Statements for the three months ended March 31, 2015.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments are effective for annual periods, and interim periods within those annual periods commencing January 1, 2017. In June 2014, AltaGas commenced a process for the adoption of the Update. In April 2015, the FASB recommended a one-year deferral of the new revenue standard, to January 1, 2018. Early adoption is not permitted.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity or a material variable interest in an unconsolidated entity 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 is not party to any 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.

In May 2009, the National Energy Board (NEB) issued a decision that set out guiding principles for a mechanism that would set aside funds for pipeline abandonment. It also established a five-year action plan for all NEB-regulated companies. In May 2014, the NEB issued a decision establishing that, by January 1, 2015, all NEB-regulated companies must have a mechanism in place to provide adequate funds to pay for pipeline abandonment. AltaGas Holdings Inc., a wholly-owned subsidiary of AltaGas, opted to comply with the NEB decision with a surety bond supplied by a surety company regulated by the Office of the Superintendent of Financial Institutions in the amount of $30 million.

In October 2014, AltaGas issued a US$92 million guarantee related to all payment obligations under a transportation agreement entered into by Heritage Gas Limited, a wholly-owned subsidiary of AltaGas. The transportation agreement is contracted with a third party owner of the transportation facility.

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

AltaGas' management is responsible for establishing and maintaining DCP and ICFR, as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The Chief Executive Officer and the Chief Financial Officer have designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that material information relating to AltaGas' business is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with United States Generally Accepted Accounting Principles (US GAAP).

On January 1, 2015, AltaGas launched a new ERP system, JD Edwards. The changes to the internal controls over financial reporting are included in the assessment to ensure that DCP and ICFR are designed to provide reasonable assurance that material information relating to AltaGas’ business is made known, reliably reported on a timely basis, and financial statements are in accordance United States Generally Accepted Accounting Principles (US GAAP).

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

($ millions)	**Q1-15**	Q4-14	Q3-14	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13
Total revenue	**744**	667	444	471	824	581	390	459
Net revenue[2]	**307**	285	217	220	297	265	247	212
Normalized operating income[2]	**125**	105	59	65	137	112	64	68
Net income before taxes	**109**	17	30	44	66	75	57	40
Net income applicable to common shares	**66**	10	17	29	40	53	43	36
($ per share)	**Q1-15**	Q4-14	Q3-14	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13
Net income applicable to common shares								
Basic	**0.49**	0.08	0.13	0.23	0.33	0.44	0.36	0.31
Diluted	**0.49**	0.08	0.13	0.23	0.32	0.43	0.35	0.30
Dividends declared	**0.44**	0.44	0.44	0.42	0.38	0.38	0.38	0.37

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

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

Significant items that impacted individual quarterly earnings were as follows:

- In second quarter 2013, AltaGas completed the acquisition of Blythe for total consideration of US$515 million; AltaGas recorded $2 million in pre-tax transaction costs;
- In second quarter 2013, AltaGas recorded an adjustment to its deferred tax liability and an income tax recovery resulting from the enactment of a Canadian tax amendment that increased the deduction arising from the tax on dividends paid on preferred shares;
- In third quarter 2013, AltaGas reported a $38 million pre-tax gain on the sale of Pacific Trail Pipelines Limited Partnership (PTP) by PNG;
- In third quarter 2013, AltaGas recorded provisions of $19 million related to the planned sale of certain non-core gas and utility assets;
- In fourth quarter 2013, AltaGas sold ECNG Energy L.P. (ECNG). AltaGas recorded a pre-tax gain of $4 million and transaction costs of $0.5 million related to this transaction;
- In fourth quarter 2013, AltaGas acquired a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. AltaGas paid for the initial 25 percent interest with 3 million shares priced at $35.69 per share and $231 million of cash;
- In fourth quarter 2013, AltaGas reclassified an other-than-temporary pre-tax loss of $4.3 million on its investment in Alterra from OCI to income for the period;
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3 million related to six wind projects under development;
- In first quarter 2014, AltaGas completed sale of Ante Creek, a gas processing facility located near Sturgeon Lake, northwestern Alberta. The transaction closed on February 12, 2014, with a realized pre-tax gain from the sale of the asset of $12 million;
- In first quarter 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2 million;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $38 million for EDS and JFP transmission pipeline assets that will be sold to NOVA Chemicals in March 2017;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $11 million for certain hydro power development projects in British Columbia;
- In third quarter 2014, Forrest Kerr was brought into service but did not contribute significantly to quarterly results due to limited power generation during the initial ramp up period;
- In fourth quarter 2014, AltaGas early redeemed $300 million of senior unsecured MTNs resulting in total pre-tax cost of $15 million; and
- In fourth quarter 2014, AltaGas recorded a pre-tax provision of $70 million for certain gas processing assets.

Consolidated Balance Sheets

(condensed and unaudited)

As at *($ millions)*	**March 31 2015**	December 31 2014
ASSETS		
Current assets		
Cash and cash equivalents	**$ 290.7**	$ 371.0
Short-term investment	**50.0**	50.0
Accounts receivable, net of allowances	**367.6**	352.4
Inventory *(note 7)*	**81.5**	155.3
Restricted cash holdings from customers	**3.5**	4.2
Regulatory assets	**9.9**	12.8
Risk management assets *(note 10)*	**78.1**	70.8
Prepaid expenses and other current assets	**33.8**	41.9
Deferred income taxes	**2.2**	-
	917.3	1,058.4
Property, plant and equipment	**5,561.4**	5,337.0
Intangible assets	**372.0**	356.9
Goodwill *(note 8)*	**832.1**	785.1
Regulatory assets	**313.9**	302.0
Risk management assets *(note 10)*	**39.6**	21.1
Deferred income taxes	**14.3**	2.2
Restricted cash holdings from customers	**11.4**	12.2
Long-term investments and other assets	**86.2**	84.6
Investments accounted for by equity method	**470.3**	453.9
	$ 8,618.5	$ 8,413.4
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 309.8**	$ 343.6
Dividends payable	**19.9**	19.8
Short-term debt	**1.8**	72.4
Current portion of long-term debt *(note 9)*	**487.4**	214.4
Customer deposits	**22.8**	34.9
Regulatory liabilities	**18.6**	10.0
Risk management liabilities *(note 10)*	**51.6**	43.5
Deferred income taxes	**-**	2.1
Other current liabilities	**28.4**	24.4
	940.3	765.1
Long-term debt *(note 9)*	**2,855.1**	3,049.6
Asset retirement obligations	**72.9**	70.9
Deferred income taxes	**505.8**	467.2
Regulatory liabilities	**148.9**	136.0
Risk management liabilities *(note 10)*	**23.6**	14.7
Other long-term liabilities	**206.7**	204.5
Future employee obligations	**141.3**	131.2
	4,894.6	4,839.2

As at ($ millions)	**March 31 2015**	December 31 2014
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 134.6 million issued and outstanding *(note 12)*	**2,785.6**	2,759.9
Preferred shares *(note 12)*	**788.4**	788.4
Contributed surplus	**15.3**	14.9
Accumulated deficit	**(178.4)**	(185.2)
Accumulated other comprehensive income	**279.2**	163.1
Total shareholders' equity	**3,690.1**	3,541.1
Non-controlling interests	**33.8**	33.1
Total equity	**3,723.9**	3,574.2
	$ 8,618.5	$ 8,413.4

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ millions except per share amounts)	Three months ended March 31 **2015**	2014
REVENUE		
Sales	**$ 132.9**	$ 268.2
Services	**170.7**	119.7
Regulated operations	**427.4**	440.7
Other revenue (loss)	**-**	0.8
Unrealized gain (loss) on risk management contracts *(note 10)*	**13.3**	(5.6)
	744.3	823.8
EXPENSES		
Cost of sales, exclusive of items shown separately	**433.1**	554.3
Operating and administrative	**117.2**	114.0
Accretion obligations	**2.7**	1.0
Depreciation, depletion and amortization	**49.9**	41.2
Provision on long-lived assets *(note 4)*	**-**	49.2
	602.9	759.7
Income (loss) from equity investments	**(5.7)**	17.3
Other income (expenses) *(note 5)*	**1.8**	9.7
Foreign exchange gain	**1.2**	0.5
Interest expense		
Short-term debt	**0.4**	0.4
Long-term debt	**29.4**	25.0
Income before income taxes	**108.9**	66.2
Income tax expense		
Current	**11.9**	9.1
Deferred	**18.5**	7.8
Net income after taxes	**78.5**	49.3
Net income applicable to non-controlling interests	**2.1**	2.1
Net income applicable to controlling interests	**76.4**	47.3
Preferred share dividends	**10.2**	7.4
Net income applicable to common shares	**$ 66.2**	$ 39.9
Net income per common share *(note 13)*		
Basic	**$ 0.49**	$ 0.33
Diluted	**$ 0.49**	$ 0.32
Weighted average number of common shares outstanding *(note 12)* *($ millions)*		
Basic	**134.3**	122.6
Diluted	**135.8**	124.4

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(condensed and unaudited)

($ millions)	Three months ended March 31 **2015**	2014
Net income after taxes	**$ 78.5**	$ 49.3
Total other comprehensive income (net of taxes)	**116.1**	51.4
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**$ 194.6**	$ 100.7
Comprehensive income attributable to:		
Non-controlling interests	**$ 2.1**	$ 2.1
Common shareholders	**192.5**	98.6
	$ 194.6	$ 100.7

Consolidated Accumulated Other Comprehensive Income (Loss) [1]

($ millions)	**Available-for-sale**	**Cash flow hedges**	**Defined benefit pension plans**	**Hedge net investments**	**Translation foreign operations**	**AOCI investee**	**Total**
Opening balance January 1, 2015	(12.0)	13.3	(9.6)	(70.9)	242.3	-	163.1
Other comprehensive income before reclassification	(12.6)	(7.8)	-	(35.4)	167.2	4.1	115.5
Amounts reclassified from other comprehensive income *(note 3)*	-	-	0.6	-	-	-	0.6
Net current period other comprehensive income (loss)	(12.6)	(7.8)	0.6	(35.4)	167.2	4.1	116.1
Ending balance, March 31, 2015[2][3][4][5]	(24.6)	5.5	(9.0)	(106.3)	409.5	4.1	279.2
Opening balance January 1, 2014	(2.9)	(10.4)	(5.7)	(35.9)	94.5	-	39.5
Other comprehensive income before reclassification	-	8.6	-	(20.7)	63.2	-	51.1
Amounts reclassified from other comprehensive income *(note 3)*	-	0.3	-	-	-	-	0.3
Net current period other comprehensive income (loss)	-	8.9	-	(20.7)	63.2	-	51.4
Ending balance, March 31, 2014 [2][3][4][5]	(2.9)	(1.5)	(5.7)	(56.6)	157.7	-	90.9

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

(2) *Available-for-sale - net of tax recovery $3.6 million (March 31, 2014 - tax recovery $0.4 million)*

(3) *Cash flow hedges - net of tax expense $1.9 million (March 31, 2014 - tax recovery $0.5 million).*

(4) *Defined benefit pension plans - net of tax recovery $3.0 million (March 31, 2014 - tax recovery $2.0 million).*

(5) *Hedge net investment - net of tax recovery $15.3 million (March 31, 2014 - tax recovery $8.2 million).*

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

($ millions)	Three months ended March 31 2015	2014
Common shares *(note 12)*		
Balance, beginning of year	**$ 2,759.9**	$ 2,211.4
Shares issued for cash on exercise of options	**4.7**	5.5
Shares issued under DRIP [1]	**21.0**	15.4
Balance, end of period	**2,785.6**	2,232.3
Preferred shares *(note 12)*		
Balance, beginning of year	**788.4**	589.6
Series E issued	**-**	(0.5)
Balance, end of period	**788.4**	589.1
Contributed surplus		
Balance, beginning of year	**14.9**	13.4
Share options expense	**0.7**	1.0
Exercise of share options	**(0.2)**	(0.4)
Forfeiture of share options	**(0.1)**	-
Balance, end of period	**15.3**	14.0
Accumulated deficit		
Balance, beginning of year	**(185.2)**	(62.1)
Net income applicable to controlling interests	**76.4**	47.3
Common share dividends	**(59.4)**	(47.0)
Preferred share dividends	**(10.2)**	(7.4)
Balance, end of period	**(178.4)**	(69.2)
Accumulated other comprehensive income (loss)		
Balance, beginning of year	**163.1**	39.5
Other comprehensive income (loss)	**116.1**	51.4
Balance, end of period	**279.2**	90.9
Total shareholders' equity	**3,690.1**	2,857.1
Non-controlling interests		
Balance, beginning of year	**33.1**	37.8
Net income applicable to non-controlling interests	**2.1**	2.1
Distribution by subsidiaries to non-controlling interests	**(1.4)**	(2.1)
Balance, end of period	**33.8**	37.8
Total equity	**$ 3,723.9**	$ 2,894.9

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

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

($ millions)	Three months ended March 31 **2015**	2014
Cash from operations		
Net income after taxes	**$ 78.5**	$ 49.3
Items not involving cash:		
Depreciation, depletion and amortization	**49.9**	41.2
Provision on long-lived assets	**-**	49.2
Accretion obligations	**2.7**	1.0
Share-based compensation	**0.7**	1.0
Deferred income tax expense	**18.5**	7.8
Gain on sale of assets	**-**	(11.4)
(Income) loss from equity investments	**5.7**	(17.3)
Unrealized (gain) loss on risk management contracts	**(13.3)**	5.6
Unrealized (gain) loss on long-term investments	**(0.3)**	-
Losses from extinguishment of debts	-	2.1
Other	**2.1**	(2.0)
Asset retirement obligations settled	**(0.5)**	(0.4)
Distributions from (contributions to) equity accounted investments	**(4.3)**	5.4
Changes in operating assets and liabilities:		
Accounts receivable	**2.5**	(4.0)
Inventory	**87.3**	63.1
Other current assets	**9.9**	12.1
Regulatory assets (current)	**4.3**	(33.4)
Accounts payable and accrued liabilities	**(22.5)**	27.9
Customer deposits	**(14.4)**	(16.1)
Regulatory liabilities (current)	**7.6**	(0.9)
Other current liabilities	**(10.5)**	(6.2)
Other operating assets and liabilities	**(1.0)**	(0.1)
	202.9	173.9
Investing activities		
Change in restricted cash holdings from customers	**1.0**	(0.1)
Acquisition of property, plant and equipment	**(114.8)**	(117.2)
Acquisition of intangible assets	**(9.3)**	(4.0)
Proceeds from dispositions of assets	**-**	26.8
Contributions to equity investments	**(5.8)**	(1.1)
Business acquisition, net of cash acquired	**(32.0)**	5.2
	(160.9)	(90.4)

($ millions)	Three months ended March 31 2015	2014
Financing activities		
Net repayment of short-term debt	**(76.3)**	(78.0)
Issuance of long-term debt, net of debt issuance costs	**-**	640.9
Repayment of long-term debt	**(3.5)**	(577.9)
Dividends - common shares	**(59.4)**	(46.8)
Dividends - preferred shares	**(10.2)**	(7.9)
Distributions to non-controlling interest	**(1.4)**	(2.1)
Net proceeds from shares issued on exercise of options	**4.3**	5.1
Net proceeds from issuance of common shares	**21.0**	15.4
Other	**(0.3)**	(0.5)
	(125.8)	(51.8)
Effect of exchange rate changes on cash and cash equivalents	**3.5**	1.7
Change in cash and cash equivalents	**(83.8)**	31.7
Cash and cash equivalents, beginning of year	**371.0**	44.8
Cash and cash equivalents, end of period	**$ 290.7**	$ 78.2

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

($ millions)	Three months ended March 31 2015	2014
Interest paid (net of capitalized interest)	**$ 37.3**	$ 23.7
Income taxes paid	**$ 8.8**	$ 9.0

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 millions of Canadian dollars unless otherwise indicated.)

1. ORGANIZATION AND OVERVIEW OF BUSINESS

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by the Corporation, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc.

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas has three business segments, Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas). AIJVLP also manages the liquefied natural gas (LNG) and the liquefied petroleum gas (LPG) export development projects.

The Power segment includes 1,449 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and the United States, along with an additional 81 MW of assets under construction and 2,360 MW of power generation in various stages of development.

The Utilities segment is predominantly comprised of natural gas distribution rate regulated utilities in Canada and the United States. The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of, capital from the regulator-approved capital investment base.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited condensed interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP) 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 2014 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 obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date to which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

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

Transactions between and amongst, AltaGas and its wholly-owned subsidiaries, and the proportionate interests in joint ventures or partnerships are eliminated on consolidation as required by US GAAP. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “Non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries is shown as an allocation of the consolidated net income and is presented separately in "Net income applicable to non-controlling interests".

SIGNIFICANT ACCOUNTING POLICIES

These interim condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2014 US GAAP annual audited Consolidated Financial Statements, except, as described below, for the exchange rates used.

Foreign Currency Translation

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

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. The exchange rate used to convert a US dollar to a Canadian dollar as at March 31, 2015 was 1.2683 (as at December 31, 2014 - 1.1601). Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI. The average exchange rate used to convert a US dollar to a Canadian dollar for the three-month period ended March 31, 2015 was 1.2411 (three months ended March 31, 2014 - 1.1035).

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain include but are not limited to depreciation, depletion and amortization expense, asset retirement obligations, long-lived and intangible assets impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate which often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. In June 2014, AltaGas commenced a process for the adoption of the Update. In April 2015, the FASB recommended a one-year deferral of the new revenue standard, to January 1, 2018. Early adoption is not permitted.

In January 2015, FASB issued ASU No. 2015-01 “Income Statement – Extraordinary and Unusual Items” to eliminate the concept of extraordinary items and alleviate uncertainty for preparers, auditors and regulators because auditors and regulators no longer will need to evaluate whether a preparer treated an unusual and/or infrequent item appropriately. The amendments in this Update are effective for fiscal years, and interim periods within those fiscal years, beginning after December 31, 2015. Early adoption is permitted.

In February 2015, FASB issued ASU No. 2015-02 “Consolidation: Amendments to Consolidation Analysis”. The amendments in this Update affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The amendments in this Update are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 31, 2015. Early adoption is permitted. AltaGas commenced a process for the adoption of the Update and the impacts of its adoption are still under assessment.

3. RECLASSIFICATION FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

		Three months ended March 31	
AOCI components reclassified	Income Statement line item	**2015**	2014
Cash flow hedges - commodity contracts			
Bond forward	Interest expense – Long-term debt	**-**	0.1
	Other income (expenses)	**-**	0.2
Defined benefit pension plans	Operating and administrative expense	**0.8**	-
	Total before income taxes	**0.8**	0.3
Deferred income taxes	Income tax expenses – Deferred	**(0.2)**	-
		$ 0.6	$ 0.3

4. PROVISION ON LONG-LIVED ASSETS

	Three months ended March 31	
	2015	2014
Gas (a)	**-**	$ 38.3
Power (b)	**-**	10.9
	-	$ 49.2

(a) First quarter 2014 included a provision of $19.6 million for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and an $18.7 million provision for related Transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements.

(b) The total provision of $10.9 million in first quarter 2014 related to certain hydro power assets under development in British Columbia.

5. OTHER INCOME (EXPENSES)

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

On February 14, 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2.3 million.

6. BUSINESS ACQUISITION

On January 8, 2015 AltaGas completed the acquisition of three western U.S. gas-fired power assets with a total generation capacity of 164 MW for US$27.4 million before adjustments for working capital (the "Acquisition"). Transaction costs, such as legal, accounting, valuation and other professional fees related specifically to the Acquisition were US$ 0.7 million, before taxes, and were expensed in the Consolidated Statement of Income, within "Operating and administrative expenses". Below is a provisional purchase price allocation based on the Statement of Financial Position as at January 8, 2015, using an exchange rate of 1.1812 to convert US dollars to Canadian dollars.

Cash Consideration	$	32.0
Total Consideration	$	32.0
Purchase Price Allocation		
<u>Assets Acquired:</u>		
Current Assets		3.3
Property, Plant and Equipment		23.2
Intangible Assets		9.2
	$	35.7
<u>Liabilities Assumed:</u>		
Current Liabilities		3.7
	$	32.0

7. INVENTORY

As at		**March 31 2015**		December 31 2014
Natural gas held in storage	**$**	**63.1**	$	136.7
Other inventory		**18.4**		18.6
	$	**81.5**	$	155.3

8. GOODWILL

As at		March 31 2015		December 31 2014
Balance, beginning of year	$	**785.1**	$	743.1
Foreign exchange translation		**47.0**		42.0
	$	**832.1**	$	785.1

9. LONG-TERM DEBT

	Maturity date	March 31 2015	December 31 2014
Credit facilities			
$1,400 million unsecured extendible revolving[(a)]	15-Dec-2018	**$ -**	$ -
Medium-term notes			
$200 million Senior unsecured - 5.49 percent	27-Mar-2017	**200.0**	200.0
$175 million Senior unsecured - 4.60 percent	15-Jan-2018	**175.0**	175.0
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**200.0**	200.0
$200 million Senior unsecured - 4.07 percent	01-Jun-2020	**200.0**	200.0
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350.0**	350.0
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300.0**	300.0
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200.0**	200.0
$300 million Senior unsecured - 3.84 percent	15-Jan-2025	**300.0**	300.0
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100.0**	100.0
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**299.7**	299.7
US$175 million Senior unsecured - floating[(b)]	13-Apr-2015	**222.0**	203.0
US$200 million Senior unsecured - floating[(c)]	24-Mar-2016	**253.7**	232.1
SEMCO long-term debt			
US$300 million SEMCO Senior secured - 5.15 percent[(d)]	21-Apr-2020	**380.5**	348.0
US$82 million SEMCO Senior secured - 4.48 percent	2-Mar-2032	**101.0**	95.1
Debenture notes			
PNG RoyNat Debenture - 3.50 percent[(e)]	15-Sep-2017	**9.5**	9.8
PNG 2018 Series Debenture - 8.75 percent[(e)]	15-Nov-2018	**10.0**	10.0
PNG 2024 CFI Debenture - 7.39 percent[(f)]	01-Nov-2024	**7.3**	7.4
PNG 2025 Series Debenture - 9.30 percent[(e)]	18-Jul-2025	**14.5**	14.5
PNG 2027 Series Debenture - 6.90 percent[(e)]	02-Dec-2027	**15.5**	15.5
Loan from Province of Nova Scotia [(g)]	31-Jul-2017	**2.1**	2.1
CINGSA capital lease - 3.50 percent	1-May-2040	**0.5**	0.5
CINGSA capital lease - 4.48 percent	4-Jun-2068	**0.2**	0.2
Promissory notes	25-Oct-2015	**1.0**	1.0
Other long-term debt		**-**	0.1
		3,342.5	3,264.0
Less current portion		**487.4**	214.4
		$ 2,855.1	$ 3,049.6

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

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

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

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

(e) 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.

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

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

10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation purchases and sells natural gas, NGL and power and issues short and long-term debt. The Corporation uses derivative instruments to reduce exposure to fluctuations in commodity prices, 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:

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

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

Summary of Fair Values	**March 31 2015**	December 31 2014
Current portion of long-term debt		
Carrying amount	**$ 487.4**	$ 214.4
Fair value of current portion of long-term debt	**$ 488.0**	$ 214.4

Summary of Fair Values	**March 31 2015**	December 31 2014
Long-term debt		
Carrying amount	**$ 2,855.1**	$ 3,049.6
Fair value of long-term debt	**$ 3,085.6**	$ 3,170.3

Summary of Fair Values	**March 31 2015**	December 31 2014
Long-term Liabilities excluding non-financial liabilities		
Carrying amount	**$ 157.1**	$ 155.6
Fair value of long-term debt	**$ 154.8**	$ 149.1

Fair Value Hierarchy

AltaGas categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly traded shares valued at the closing price as at the balance sheet date.

Level 2 - fair values are determined based on inputs other than quoted prices that are observable for the asset or liability. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices, interest rates and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange and interest rate yield curves. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

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

March 31, 2015	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	**$ 290.7**	**-**	**-**	**$ 290.7**
Short-term investments	**$ 50.0**	**-**	**-**	**$ 50.0**
Risk management assets - current	**-**	**$ 78.1**	**-**	**$ 78.1**
Risk management assets - non-current	**-**	**$ 39.6**	**-**	**$ 39.6**
Long-term investments and other assets (1)	**$ 32.2**	**-**	**-**	**$ 32.2**
Financial liabilities				
Risk management liabilities - current	**-**	**$ 51.6**	**-**	**$ 51.6**
Risk management liabilities - non-current	**-**	**$ 23.6**	**-**	**$ 23.6**
Current portion of long-term debt	**-**	**$ 488.0**	**-**	**$ 488.0**
Long-term debt	**-**	**$ 3,085.6**	**-**	**$ 3,085.6**
Other long-term liabilities (2)	**-**	**$ 154.8**	**-**	**$ 154.8**

December 31, 2014	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	$ 371.0	-	-	$ 371.0
Short-term investment	$ 50.0	-	-	$ 50.0
Risk management assets - current	-	$ 70.8	-	$ 70.8
Risk management assets - non-current	-	$ 21.1	-	$ 21.1
Long-term investments and other assets (1)	$ 46.3	-	-	$ 46.3
Financial Liabilities				
Risk management liabilities - current	-	$ 43.5	-	$ 43.5
Risk management liabilities - non-current	-	$ 14.7	-	$ 14.7
Current portion of long-term debt	-	$ 214.4	-	$ 214.4
Long-term debt	-	$ 3,170.3	-	$ 3,170.3
Other long-term liabilities (2)	-	$ 149.1	-	$ 149.1

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

(2) *Excludes non-financial liabilities*

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

	Three months ended March 31 2015	2014
Natural gas	**$ 1.5**	$ (5.0)
Storage optimization	**(0.9)**	1.9
NGL frac spread	**3.4**	(0.8)
Power	**9.3**	(1.6)
Heat rate	**(0.3)**	(0.2)
Foreign exchange	**0.2**	0.1
Embedded derivative	**0.1**	-
	$ 13.3	$ (5.6)

Offsetting of Derivative Assets and Derivative Liabilities

As at March 31, 2015

Risk management assets (1)	**Gross amounts of recognized assets/liabilities**	**Gross amounts offset in Balance Sheet**	**Net amounts presented in Balance Sheet**
Natural gas	**$ 89.2**	**$ 38.7**	**$ 50.5**
	$ 89.2	**$ 38.7**	**$ 50.5**
Risk management liabilities (2)			
Natural gas	**$ 90.7**	**$ 38.7**	**$ 52.0**
Total	**$ 90.7**	**$ 38.7**	**$ 52.0**

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $33.7 million and risk management assets (non-current) balance of $16.8 million.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $36.0 million and risk management liabilities (non-current) balance of $16.0 million.*

As at March 31, 2014

Risk management assets (1)	Gross amounts of recognized assets/liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	$ 67.8	$ 50.1	$ 17.7
Storage optimization	2.9	1.3	1.6
	$ 70.7	$ 51.4	$ 19.3
Risk management liabilities (2)			
Natural gas	$ 68.7	$ 50.1	$ 18.6
Storage optimization	2.3	1.3	1.0
	$ 71.0	$ 51.4	$ 19.6

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $16.2 million and risk management assets (non-current) balance of $3.1 million.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $17.7 million and risk management liabilities (non-current) balance of $1.8 million.*

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.

11. LONG-TERM LIABILITIES

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

The fair value of the firm commitment on initial recognition was measured using an estimated 2 percent inflation rate and 4.27 percent discount rate. This fair value of the NTL liability has been recorded within other current liabilities for $10.8 million and other long-term liabilities for $157.1 million. Accretion expenses for the three months ended March 31, 2015 were $1.7 million (March 31, 2014 - nil). The initial consideration and the fair value of the future considerations, for a total amount of $258.5 million, has been recognized within the intangible assets and depreciated over 60 years, the term of the EPA with BC Hydro.

12. SHAREHOLDERS' EQUITY

Authorization

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

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2014	122,305,293		2,211.4
Shares issued for cash on exercise of options	989,162		24.9
Shares issued on public offering	9,027,500		449.2
Deferred taxes on share issuance cost	-		4.2
Shares issued under DRIP	1,619,794		70.2
December 31, 2014	133,941,749		2,759.9
Shares issued for cash on exercise of options	178,987		4.7
Shares issued under DRIP	512,820		21.0
Issued and outstanding at March 31, 2015	**134,633,556**	**$**	**2,785.6**

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2014	8,000,000		194.1
Deferred taxes on share issuance costs	-		1.8
December 31, 2014	8,000,000		195.9
Issued and outstanding at March 31, 2015	**8,000,000**	**$**	**195.9**

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

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

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

	Three months ended	
		March 31
Weighted Average Shares Outstanding	**2015**	2014
Number of shares - basic	**134.3**	122.6
Dilutive equity instruments [1]	**1.5**	1.8
Number of shares - diluted	**135.8**	124.4

[1] *Includes all options that have a strike price lower than the market share price of AltaGas' common shares at March 31, 2015 and 2014, respectively.*

For three months ended March 31, 2015, 757,000 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (December 31, 2014 - 642,000 options).

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at March 31, 2015, 8,467,062 shares were reserved for issuance under the plan. As at March 31, 2015, options granted under the plan generally have a term between 6 and 10 years until expiry and vest no longer than over a four-year period.

As at March 31, 2015, the unexpensed fair value of share option compensation cost associated with future periods was $4.5 million (December 31, 2014 - $5.2 million).

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

	Options outstanding	
	Number of options	Exercise price[1]
Share options outstanding, December 31, 2014	5,123,655	$ 30.28
Granted	115,000	41.19
Exercised	(178,987)	24.10
Forfeited	(63,375)	35.35
Share options outstanding, March 31, 2015	**4,996,293**	**$ 30.69**
Share options exercisable, March 31, 2015	**2,855,668**	**$ 25.73**

(1) *Weighted average.*

The following table summarizes the employee share option plan as at March 31, 2015:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Exercise price
$13.65 to $18.00	292,170	$ 15.40	4.1402	292,170	$ 15.40
$18.01 to $25.08	1,048,550	20.74	5.0932	1,034,300	20.69
$25.09 to $50.89	3,655,573	34.77	6.1541	1,529,198	31.12
	4,996,293	**$ 30.69**	**5.8137**	**2,855,668**	**$ 25.73**

Equity-based Compensation Plan

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 the three months ended March 31, 2015, the compensation expense recorded was $1.4 million (three months ended March 31, 2014 - $1.2 million).

As at March 31, 2015, the unexpensed fair value of equity-based compensation cost associated with future periods was $13.7 million (December 31, 2014 - $11.7 million).

13. NET INCOME APPLICABLE TO COMMON SHARES

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

	Three months ended March 31 2015	March 31 2014
Numerator:		
Net income applicable to controlling interests	**$ 76.4**	$ 47.3
Less: Preferred share dividends	**10.2**	7.4
Net income applicable to common shares	**$ 66.2**	$ 39.9
Denominator:		
Weighted average number of common shares outstanding	**134.3**	122.6
Dilutive equity instruments[1]	**1.5**	1.8
Weighted average number of common shares outstanding - diluted	**135.8**	124.4
Basic net income applicable per common share	**$ 0.49**	$ 0.33
Diluted net income applicable per common share	**$ 0.49**	$ 0.32

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at March 31, 2015 and 2014.*

14. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Commitments

AltaGas has long-term natural gas purchase arrangements, service agreements, power purchase agreements, and operating leases for office space, office equipment and automobile equipment, all of which are transacted at market prices and in the normal course of business.

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2015 to 2019, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $10.7 million over the next 7 years, of which $7.6 million is payable in the next five years.

In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. AltaGas is obligated to pay approximately $3.4 million per annum over the term of the contract for storage services.

In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines at the Blythe facility over 116,000 EOH/CT, or 20 years, whichever comes first, in exchange for $212.2 million payable over the next 19 years, of which $51.5 million is expected to be paid over the next five years.

Guarantees

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

Contingencies

AltaGas is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators. On January 20, 2015, the AUC released the AUC Loss Hearings for the complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology used for the power distribution in Alberta. The AUC will proceed to determine the relief and remedies to be granted in accordance with its findings and conclusions regarding its authority and jurisdiction made in its decision. AltaGas is one of the respondents to the complaint and it has assessed that it may incur additional payments for transmission charges, but the timing and amount, or range of amounts, required to settle the claim cannot be estimated and, accordingly, no accrual of the loss contingency was recognized as at March 31, 2015.

15. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality and other factors affecting the payment of future benefits.

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

	Canada		**United States**		**Total**	
Three months ended March 31, 2015	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**	**Post-retirement Benefits**	**Post-retirement Benefits**
Current service cost	**$ 1.7**	**$ 0.2**	**$ 1.9**	**$ 0.5**	**$ 3.6**	**$ 0.7**
Interest cost	**1.3**	**0.1**	**2.6**	**0.8**	**3.9**	**0.9**
Expected return on plan assets	**(1.3)**	**-**	**(3.6)**	**(1.1)**	**(4.9)**	**(1.1)**
Amortization of net actuarial loss	**0.5**	**-**	**-**	**-**	**0.5**	**-**
Amortization of regulatory asset	**0.4**	**-**	**1.0**	**0.2**	**1.4**	**0.2**
Net benefit cost recognized	**$ 2.6**	**$ 0.3**	**$ 1.9**	**$ 0.4**	**$ 4.5**	**$ 0.7**

	Canada		United States		Total	
Three months ended March 31, 2014	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Post-retirement Benefits	Post-retirement Benefits
Current service cost	$ 1.4	$ 0.1	$ 1.4	$ 0.3	$ 2.8	$ 0.4
Interest cost	1.3	0.1	2.3	0.8	3.6	0.9
Expected return on plan assets	(1.2)	-	(3.0)	(1.0)	(4.2)	(1.0)
Amortization of past service cost	-	-	-	(0.1)	-	(0.1)
Amortization of net actuarial loss	0.1	-	0.2	0.1	0.3	0.1
Amortization of regulatory asset	0.2	-	0.5	0.1	0.7	0.1
Net benefit cost recognized	$ 1.8	$ 0.2	$ 1.4	$ 0.2	$ 3.2	$ 0.4

16. SEASONALITY

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

The power generation in the run-of-river hydro-projects Forrest Kerr and Volcano Creek occurs substantially from mid-second quarter through the fourth quarter, resulting in weaker results in the first quarter as depreciation expense is recorded on a straight-line basis.

17. SUBSEQUENT EVENTS

Subsequent events have been reviewed through April 30, 2015, the issuance date of these interim unaudited financial statements.

On April 14, 2015, AltaGas issued US$125 million senior unsecured medium-term notes (MTNs). The notes carry a floating coupon rate of three months LIBOR plus 0.85 percent and mature on April 17, 2017.

18. SEGMENTED INFORMATION

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

Gas	– NGL processing and extraction plants; – transmission pipelines to transport natural gas and NGL; – natural gas gathering lines and field processing facilities; – purchase and sale of natural gas and electricity; – natural gas storage facilities; – LNG and LPG development projects; and – equity investments in a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents.
Power	– coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase agreements, both operational and under construction; and – 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 March 31, 2015	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 284.7**	**$ 110.2**	**$ 430.8**	**-**	**$ (94.7)**	**$ 731.0**
Unrealized gain on risk management	**-**	**-**	**-**	**13.3**	**-**	**13.3**
Cost of sales	**(194.4)**	**(60.4)**	**(271.2)**	**-**	**92.9**	**(433.1)**
Operating and administrative	**(42.6)**	**(13.8)**	**(56.5)**	**(6.1)**	**1.8**	**(117.2)**
Accretion of obligations	**(0.9)**	**(1.8)**	**-**	**-**	**-**	**(2.7)**
Depreciation, depletion and amortization	**(15.2)**	**(14.6)**	**(18.5)**	**(1.6)**	**-**	**(49.9)**
Income (loss) from equity investments	**(2.0)**	**(4.5)**	**0.8**	**-**	**-**	**(5.7)**
Other income (expenses)	**-**	**-**	**0.5**	**1.3**	**-**	**1.8**
Foreign exchange gain	**-**	**-**	**-**	**1.2**	**-**	**1.2**
Interest expense	**-**	**-**	**-**	**(29.8)**	**-**	**(29.8)**
Income (loss) before income taxes	**$ 29.6**	**$ 15.1**	**$ 85.9**	**$ (21.7)**	**-**	**$ 108.9**
Net additions (reductions) to:						
Property, plant and equipment[1]	**$ 21.6**	**$ 65.0**	**$ 22.9**	**$ 0.4**	**-**	**$ 109.9**
Intangible assets	**$ 0.1**	**$ 9.3**	**$ 0.4**	**$ 5.8**	**-**	**$ 15.6**
As at March 31, 2015:						
Goodwill	**$ 161.4**	**-**	**$ 670.7**	**-**	**-**	**$ 832.1**
Segmented assets	**$ 2,303.6**	**$ 2,496.9**	**$ 3,231.2**	**$ 586.8**	**-**	**$ 8,618.5**

Three months ended March 31, 2014	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 391.7	$ 103.6	$ 443.8	-	$ (109.7)	$ 829.4
Unrealized loss on risk management	-	-	-	(5.6)	-	(5.6)
Cost of sales	(290.3)	(74.9)	(296.1)	-	107.0	(554.3)
Operating and administrative	(45.5)	(12.6)	(51.8)	(6.8)	2.7	(114.0)
Accretion of obligations	(0.9)	(0.1)	-	-	-	(1.0)
Depreciation, depletion and amortization	(17.0)	(7.6)	(15.9)	(0.7)	-	(41.2)
Provision on property, plant and equipment	(38.3)	(10.9)	-	-	-	(49.2)
Income from equity investments	9.2	7.4	0.7	-	-	17.3
Other income (expenses)	11.4	0.1	0.5	(2.3)	-	9.7
Foreign exchange gain	-	-	-	0.5	-	0.5
Interest expense	-	-	-	(25.4)	-	(25.4)
Income (loss) before income taxes	$ 20.3	$ 5.0	$ 81.2	$ (40.3)	-	$ 66.2
Net additions (reductions) to:						
Property, plant and equipment[1]	$ (7.9)	$ 104.2	$ 55.5	$ 1.9	-	$ 153.7
Intangible assets	$ 0.1	$ 0.1	$ 0.6	$ 3.3	-	$ 4.1
As at March 31, 2014:						
Goodwill	$ 161.4	-	$ 599.8	-	-	$ 761.2
Segmented assets	$ 2,072.0	$ 1,982.3	$ 2,827.1	$ 496.0	-	$ 7,377.4

(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)

FINANCIAL HIGHLIGHTS[1] *($ millions unless otherwise indicated)*	**Q1-15**	Q4-14	Q3-14	Q2-14	Q1-14
Net Revenue[2]					
Gas	**$ 88.3**	$ 97.5	$ 102.6	$ 102.6	$ 122.0
Power	**45.3**	72.7	43.0	32.6	36.2
Utilities	**160.9**	125.2	72.5	83.2	148.9
Corporate	**14.7**	(8.7)	1.3	3.1	(7.8)
Intersegment Elimination	**(1.8)**	(1.6)	(2.0)	(1.5)	(2.7)
	$ 307.4	$ 285.0	$ 217.4	$ 219.9	$ 296.5
EBITDA[2]					
Gas	**$ 45.7**	$ 58.1	$ 55.8	$ 57.1	$ 76.5
Power	**31.6**	56.5	30.7	21.6	23.6
Utilities	**104.4**	73.9	23.6	35.8	97.1
Corporate	**(4.8)**	(24.2)	(6.3)	(7.3)	(9.0)
	$ 176.9	$ 164.3	$ 103.8	$ 107.2	$ 188.2
Operating Income (Loss)[2]					
Gas	**$ 29.6**	$ (29.5)	$ 38.3	$ 39.5	$ 20.3
Power	**15.1**	42.2	19.3	13.0	5.0
Utilities	**85.9**	57.2	7.8	19.9	81.2
Corporate	**(6.4)**	(25.4)	(7.1)	(8.0)	(9.7)
	$ 124.2	$ 44.7	$ 58.3	$ 64.4	$ 96.8
Normalized Operating Income (Loss)[2]					
Gas	**$ 30.8**	$ 40.8	$ 39.0	$ 40.0	$ 47.5
Power	**15.2**	16.0	19.4	13.2	15.9
Utilities	**85.9**	57.2	7.8	19.9	81.2
Corporate	**(6.9)**	(8.9)	(6.9)	(8.6)	(7.6)
	$ 125.0	$ 105.1	$ 59.3	$ 64.5	$ 137.0

(1) Columns may not add due to rounding.

(2) Non-GAAP financial measure.

Supplementary Quarterly Operating Information

(unaudited)

	Q1-15	Q4-14	Q3-14	Q2-14	Q1-14
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	**1,498**	1,551	1,447	1,476	1,573
Extraction volumes (Bbls/d)(1) (2)	**73,293**	76,203	72,969	69,867	72,015
Frac spread - realized ($/Bbl)(1) (3)	**11.43**	16.29	14.19	17.31	25.84
Frac spread - average spot price ($/Bbl)(1)(4)	**3.72**	11.18	16.58	18.14	35.76
POWER					
Volume of power sold (GWh)(1)	**1,449**	1,457	1,464	1,067	1,181
Average price realized on sale of power ($/MWh)(1) (5)	**54.62**	63.77	74.51	55.92	69.36
Alberta Power Pool average spot price ($/MWh)(1)	**29.02**	30.47	64.34	42.43	60.60
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	**13.0**	10.6	3.1	6.2	12.8
Natural gas deliveries - transportation (PJ)(6)	**1.9**	1.4	1.0	1.2	1.9
U.S. utilities					
Natural gas deliveries end use (Bcf) (6)	**32.1**	23.1	6.1	10.6	32.5
Natural gas deliveries transportation (Bcf) (6)	**13.7**	11.7	8.5	8.4	12.4
Service sites(7)	**564,173**	562,746	554,837	553,320	557,062
Degree day variance from normal - AUI (%)(8)	**(11.3)**	(3.1)	(6.2)	10.8	5.5
Degree day variance from normal - Heritage Gas (%)(8)	**15.7**	(8.4)	(1.5)	3.7	3.9
Degree day variance from normal - SEMCO Gas (%)(9)	**16.4**	5.1	44.7	9.9	24.1
Degree day variance from normal - ENSTAR (%)(9)	**(8.0)**	(10.5)	(8.3)	(7.7)	(8.3)

(1) Average for the period.

(2) Includes Harmattan NGL processed on behalf of customers.

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

(4) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.

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

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

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

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

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

Other Information

DEFINITIONS

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

ABOUT ALTAGAS

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

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