



NEWS RELEASE

ALTAGAS REPORTS SECOND QUARTER RESULTS

Calgary, Alberta (July 28, 2011) – AltaGas Ltd. (AltaGas) (TSX: ALA) today reported higher funds from operations for the three months ended June 30, 2011, of \$46.7 million (\$0.56 per share) compared to \$44.3 million (\$0.54 per share) for the same period 2010. EBITDA for the three months ended June 30, 2011, was \$56.7 million (\$0.68 per share), compared to \$58.9 million (\$0.72 per share) for the same period 2010.

Normalizing for the impact of all mark-to-market accounting in second quarter, income before income taxes was \$24.3 million compared to \$23.3 million for the same period 2010. Net income applicable to common shares for the three months ended June 30, 2011, was \$16.6 million (\$0.20 per share), compared to \$28.4 million (\$0.35 per share) for the same period 2010, mainly due to the impact of mark-to-market accounting.

“The business segments reported higher operating income of \$45.7 million in second quarter this year compared to \$44.4 million for the same period last year,” said David Cornhill, Chairman and CEO of AltaGas. “We continue to benefit from our diversified portfolio of energy infrastructure assets. During the quarter, strong volumes and frac spreads in our Gas business mitigated the impact of weaker power prices in Alberta. Although processing volumes at some of our facilities were lower than anticipated we maintain a positive outlook for the remainder of 2011. The Utility business benefited from rate base growth in both Alberta and Nova Scotia and hedges in the Power business helped offset the impact of weaker spot prices.”

AltaGas has several significant capital projects underway, creating shareholder value for the long-term. The Company is focused on delivering these projects on time and on budget. On June 20, 2011, AltaGas received the final regulatory approval required to begin construction of the Gordondale gas plant, a 120 Mmcf/d deep cut facility, expected to be fully operational in late 2012. The first phase of Gordondale is on track to deliver 15 Mmcf/d to the Pouce Coupe facility via the Henderson Pipeline in third quarter 2011. The Harmattan Co-stream project is on schedule to be in service late in first quarter 2012. Pipeline construction is expected to begin in August. Construction at the Forrest Kerr site is progressing as planned with excavation of the access tunnels approximately 35 percent complete. Tunneling has begun on the power tunnel and the in-take design is complete.

FINANCIAL HIGHLIGHTS⁽¹⁾:

- Earnings before interest, taxes, depreciation and amortization (EBITDA) were \$56.7 million (\$0.68 per share) for second quarter 2011, compared to \$58.9 million (\$0.72 per share) for same quarter 2010.
- Funds from operations were \$46.7 million (\$0.56 per share) for second quarter 2011, up from \$44.3 million (\$0.54 per share) for same period 2010.
- Net debt on June 30, 2011 was \$981.2 million, compared to \$932.7 million at March 31, 2011 and \$902.4 million at December 31, 2010. AltaGas' debt to total capitalization ratio as at June 30, 2011 was 44.8 percent, versus 43.3 percent at March 31, 2011 and 42.7 percent as at December 31, 2010.
- AltaGas executed a new \$125 million unsecured bilateral letter of credit facility on April 26, 2011.
- AltaGas extended the term of the \$600 million and \$75 million credit facilities to four years to May 30, 2015.

(1) Includes non-GAAP financial measures. See discussion in “Non-GAAP Financial Measures” section of this quarter’s MD&A.

IN THE SECOND QUARTER ALTAGAS:

- Received regulatory and environmental approvals required to proceed with construction of the Gordondale gas plant.
- Began construction of the Henderson pipeline, the first phase of Gordondale, which will bring 15 Mmcf/d of early gas supply to the Pouce Coupe facility by the end of third quarter.
- Completed negotiations on two draft Impact Benefit Agreements (IBAs) with the Tahltan Central Council for the proposed McLymont Creek and Volcano Creek run-of-river projects. The ratification vote will take place September 9 to September 15, 2011.

- Filed Heritage Gas' General Tariff Application on June 15, 2011, with the Nova Scotia Utility Review Board.
- Commenced the Younger extraction facility turnaround on June 13, which returned to partial operations on July 3 and full operation on July 13.
- Acquired a 40 percent interest in a 40 Mmcf/d (gross) gas processing facility in the Pine Creek area.
- Completed an expansion at the Alder Flats gas plant, increasing capacity by 10 Mmcf/d.

CONFERENCE CALL AND WEBCAST DETAILS:

AltaGas will hold a conference call today at 10:00 a.m. MT (12:00 p.m. ET) to discuss second quarter 2011 financial and operating results and other general issues and developments concerning AltaGas.

Members of the media, investment communities and other interested parties may dial (416) 340 2218 or call toll free at 1 866 226 1793. No pass code is required. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_webcasts

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 1707067. The replay expires at midnight (ET) on August 4, 2011. The webcast will be archived for one year.

The complete second quarter report for 2011, including Management's Discussion and Analysis and unaudited financial statements, is available on www.altagas.ca in the Investors/Financial Reports section of its website.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and unaudited 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, the Corporation) as at and for the three and six months ended June 30, 2011, compared to the three and six months ended June 30, 2010. This MD&A dated July 28, 2011, should be read in conjunction with the accompanying unaudited interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three and six months ended June 30, 2011, with the 2011 prior period interim MD&A and with the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2010.

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 an 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 and opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Consolidated Outlook"; "Growth Capital"; "Gas Outlook"; "Power Outlook"; "Utilities Outlook" and "Corporate Outlook".

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 segment's 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 Ltd. and AltaGas Income Trust (the "Trust"), including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, and Proxy Statement, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com.

CONSOLIDATED FINANCIAL REVIEW

The second quarter report follows the continuity of interest basis of accounting whereby the Corporation is considered a continuation of AltaGas Income Trust. As a result, the report includes the Trust's results of operations for the period up to and including June 30, 2010 and the Corporation's results of operations thereafter.

As at January 1, 2011, the Corporation reorganized the way in which it records and allocates certain costs related to operating its businesses. Comparative 2010 results have been restated to reflect these changes.

AltaGas is a qualified entity for the deferral period permitted by AcSB, based on the Rate-Regulated Activities (RRA) of AUI and Heritage Gas. AltaGas has elected to use the deferral offered by the AcSB given the uncertainty with respect to the application of IFRS to the RRA. AltaGas has reassessed the accounting policy choices available and determined that the most appropriate decision for AltaGas' business activities is the use of US GAAP effective January 1, 2012.

US GAAP reporting is generally permitted by Canadian securities laws and Toronto Stock Exchange for companies subject to reporting obligations under US securities laws (ref. NI 52-107 Acceptable Accounting Principles and Auditing Standards). On July 4, 2011, AltaGas was granted exemptive relief by the Alberta Securities Commission from the NI 52-107 rules, to prepare its financial statements in accordance with US GAAP without being registered with the US Securities and Exchange Commission (SEC). The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

AltaGas commenced a process to transition from Canadian GAAP to US GAAP establishing a project team to plan for and achieve a smooth transition to US GAAP. Management provides regular progress reports to the Audit Committee of the Board of Directors on the status of the US GAAP implementation project.

Results of Operations by Reporting Segment

Operating income ⁽¹⁾ (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
		June 30		June 30
	2011	2010	2011	2010
Gas	25.2	19.6	55.4	42.2
Power	15.5	20.8	42.1	37.3
Utilities	5.0	4.0	16.7	10.8
Sub-total: Operating segments	45.7	44.4	114.2	90.3
Corporate	(11.4)	(8.8)	(21.5)	(17.3)
	34.3	35.6	92.7	73.0

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

Three Months Ended June 30

Net income applicable to common shares for second quarter 2011 was \$16.6 million (\$0.20 per share) compared to \$28.4 million (\$0.35 per share) for same period 2010. In second quarter 2011, the Corporation reported an income tax recovery of \$3.3 million compared to an income tax recovery of \$2.1 million for same period 2010.

In second quarter 2011, AltaGas reported a pre-tax unrealized loss on risk management contracts of \$4.6 million compared to a pre-tax gain of \$3.8 million in same quarter 2010. In the quarter the Corporation also reported a pre-tax unrealized loss related to an equity investment of \$3.8 million compared to a pre-tax unrealized loss of \$0.8 million in second quarter 2010. Normalizing for the impact of all mark-to-market accounting, net income before tax in second quarter 2011 was \$24.3 million compared to \$23.3 million in same quarter 2010.

The Gas segment reported higher operating income in second quarter 2011 compared to same quarter 2010 due to higher frac spreads and increased volume of natural gas liquids processed. The Power segment reported lower operating income in second quarter 2011 compared to same quarter 2010 due to lower power prices realized partially offset by the addition of the cogeneration facility at the Harmattan complex and stronger results from Bear Mountain Wind Park (Bear Mountain). The Utility segment reported higher operating income in second quarter 2011 compared to same quarter 2010 due to higher applied-for recoverable costs and rate base growth at Heritage Gas Ltd. (Heritage Gas) and AltaGas Utilities Inc. (AUI). Excluding the impact of risk management contracts, the Corporate segment reported a larger loss in second quarter 2011 compared to same quarter last year. The greater loss was mainly due to a mark-to-market loss related to an equity investment in a publicly traded company.

On a cash flow basis, funds from operations for second quarter 2011 were \$46.7 million (\$0.56 per share) compared to \$44.3 million (\$0.54 per share) in second quarter 2010. EBITDA in second quarter 2011 was \$56.7 million (\$0.68 per share) compared to \$58.9 million (\$0.72 per share) in same period last year. In second quarter 2011, AltaGas declared dividends to common shareholders of approximately 59 percent of funds from operations.

On a consolidated basis, net revenue for second quarter 2011 was \$113.7 million compared to \$124.8 million in same period 2010. The Gas segment reported higher net revenue compared to the prior year due to higher realized frac exposed volumes, higher frac margins and lower bad debt provision, partially offset by lower gas processing volumes and fee-for-service revenues and lower transmission revenues. Net revenue in the Power segment decreased due to lower power prices and higher transmission and environmental costs, partially offset by the addition of the Harmattan gas-fired cogeneration facility and higher results from Bear Mountain. The Utility segment reported higher net revenue due to higher applied-for recoverable costs and rate base growth at Heritage Gas and AUI. The Corporate segment recorded lower net revenue due to higher unrealized losses on risk management contracts and a mark-to-market loss on an equity investment.

Operating and administrative expense for second quarter 2011 was \$61.7 million, down from \$62.1 million in second quarter 2010. The decrease was primarily due to lower general and administrative costs partially offset by an increase in operating costs at extraction facilities due to higher volumes.

Amortization expense for second quarter 2011 was \$21.7 million compared to \$22.6 million in same period 2010. Accretion expense for second quarter 2011 was \$0.6 million compared to \$0.7 million for same period 2010. The decreases were due to a change in estimates in third quarter 2010 for the expected remaining useful lives of some assets within the Gas segment.

Interest expense in second quarter 2011 was \$13.7 million compared to \$13.1 million for same period 2010. The increase was due to a higher average borrowing rate of 6.4 percent (2010 - 5.2 percent) partially offset by a lower average debt balance of \$995.4 million (2010 - \$1,039.5 million).

In second quarter 2011, an income tax recovery of \$3.3 million was reported compared to a recovery of \$2.1 million in second quarter 2010. Future income tax expense increased as a result of conversion to a corporate structure; however the increased future income tax expense was offset by an adjustment to future tax liabilities. The Corporation has followed the practice of determining the future tax liability utilizing an estimated future tax rate of 26 percent applied to the difference between the book carrying values and the tax bases of assets and liabilities. In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflects the substantively enacted tax rates anticipated to be in effect in the periods in which the differences are expected to reverse. The revised future tax rate resulted in a decrease of \$6.8 million to future income tax liabilities.

Six Months Ended June 30

Net income applicable to common shares for first half 2011 was \$43.1 million (\$0.52 per share) compared to \$64.8 million (\$0.80 per share) for same period 2010. AltaGas reported income tax expenses of \$5.5 million in first half 2011 compared to income tax recoveries of \$7.5 million for same period 2010.

For the six months ended June 30, 2011, AltaGas reported a pre-tax unrealized loss on risk management contracts of \$12.0 million compared to a pre-tax gain of \$9.1 million for same period 2010. In the first half 2011 the Corporation also reported a pre-tax unrealized loss related to an equity investment of \$6.5 million compared to a pre-tax unrealized loss of \$2.2 million in the same period 2010. Normalizing for the impact of all mark-to-market accounting, net income before tax for the six months ended June 30, 2011, was \$72.6 million compared to \$50.3 million for the same period 2010.

The Gas segment reported higher operating income in first half 2011 compared to same period in 2010 due to higher frac exposed volumes, higher frac margins, sale of the Groundbirch facility, settlement of a take-or-pay contract, contributions from new and expanded gas processing facilities, lower amortization and administration costs, higher fees earned from increased extraction volumes and lower provision for doubtful customer receivables. These increases were partially offset by lower volumes processed at some gas processing facilities, lower daily contract quantity at the Suffield system and lower margins realized in the natural gas storage business. The Power segment reported higher operating income in first half 2011 compared to same period 2010 as a result of higher earnings from Bear Mountain and natural gas-fired peaking plants and the addition of the gas-fired cogeneration facility at the Harmattan complex. The Utility segment reported higher operating income in first half 2011 compared to same period 2010 mainly due to colder weather in Alberta and Nova Scotia in first quarter 2011, growth in rate base at Heritage Gas and AUI and higher applied-for recoverable costs. Excluding the impact of risk management contracts, the Corporate segment reported a higher loss in first half 2011 compared to same period last year. The increase was due to a mark-to-market loss related to an equity investment in a publicly traded company.

On a cash flow basis, funds from operations for first half 2011 were \$110.6 million (\$1.33 per share) compared to \$95.6 million (\$1.18 per share) for same period 2010. EBITDA for first half 2011 was \$137.2 million (\$1.65 per share) compared to \$120.0 million (\$1.48 per share) for same period last year. For the six months ended June 30, 2011, AltaGas declared dividends to common shareholders of approximately 50 percent of funds from operations.

On a consolidated basis, net revenue for the six months ended June 30, 2011, was \$251.4 million compared to \$252.0 million in same period 2010. The Gas segment reported higher net revenue compared to the prior year due to higher frac exposed volumes, higher frac margins, the sale of the Groundbirch facility, settlement of a take-or-pay contract, contributions from new and expanded gas processing facilities and higher fees earned from increased extraction volumes. The higher net revenue was partially offset by lower throughput at some processing facilities, lower transmission revenues and lower margins realized in the natural gas storage business. Net revenue in the Power segment was higher due to higher Alberta spot power prices, increased generation from Bear Mountain and the addition of the Harmattan cogeneration facility. The increase was partially offset by lower revenue from lower hedged volumes and lower hedged prices. The Utilities reported higher net revenue mainly due to colder weather in Alberta and Nova Scotia in first quarter 2011 compared to same period 2010 and year-over-year growth in rate base. The Corporate segment recorded lower net revenue due to higher unrealized losses on risk management contracts and a mark-to-market loss on an equity investment.

Operating and administrative expense for first half 2011 was \$126.1 million, up from \$122.9 million for same period 2010. The increase was primarily due to incremental costs at extraction facilities due to higher volumes, partially offset by lower general and administrative expenses.

Amortization expense for first half 2011 was \$43.3 million compared to \$45.6 million for same period 2010. Accretion expense for first half 2011 was \$1.2 million compared to \$1.4 million for same period 2010. The decreases were primarily due to a change in estimates for the expected remaining useful lives of some assets within the Gas segment.

Interest expense for first half 2011 was \$26.6 million compared to \$24.6 million for same period 2010. The increase was due to a higher average borrowing rate of 6.3 percent (2010 - 4.9 percent) partially offset by lower average debt balances of \$957.8 million (2010 - \$1,034.9 million) primarily as a result of the preferred share issuance in August 2010, the proceeds of which were used to reduce debt.

In first half 2011, an income tax expense of \$5.5 million was reported compared to a recovery of \$7.5 million in same period 2010. The increase was due to higher income subject to tax as a result of the conversion to a corporate structure. The increased income tax expense was partially offset by a decrease of \$6.8 million to future income tax liabilities. The Corporation has followed the practice of determining the future tax provision utilizing an estimated future tax rate of 26 percent applied to the difference between the book carrying values and the tax bases of assets and liabilities. In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflects the substantively enacted tax rates anticipated to be in effect in the periods in which the differences are expected to reverse.

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger operating results in 2011 compared to 2010. Income before taxes is expected to be higher in 2011 compared to 2010 due to stronger results from its diversified portfolio of energy assets. On a net income basis, the Corporation expects to report higher future income tax expense based on being a corporation for a full year. Partially offsetting the impact of higher taxes resulting from converting to a corporate structure is the adjustment to future tax rates which is expected to result in an average annual effective tax rate of 18 percent. The Corporation has approximately \$1.3 billion in tax pools and based on current estimates for capital expenditures and taxable income does not generally expect to be cash taxable until 2016.

Higher earnings are expected from higher volumes processed at certain gas processing and extraction facilities as producers look to increase net backs from liquids-rich gas and higher realized frac spreads. Gas processing throughput during early July has averaged 406 Mmcf/d compared to the first and second quarter of 375 Mmcf/d and 391 Mmcf/d, respectively. Stronger results are expected in the Gas segment despite turnarounds at the Younger extraction plant (Younger) and Harmattan and lower daily take-or-pay volumes on Suffield. Furthermore, certain regions continue to have limited producer activity as a result of lower natural gas prices and where gas composition is not considered to be rich. As a result, throughput at certain gas processing facilities is expected to be lower than the previous year.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve for 2011, management expects NGL frac spreads to average approximately \$38/Bbl after deducting extraction premiums compared to \$29/Bbl in 2010. In 2011, the Corporation estimates that 13 percent of total extraction volumes will be exposed to frac spread. For the remainder of 2011, approximately 65 percent of the exposure has been hedged at an average price of \$26.85/Bbl. For 2012, AltaGas has hedged approximately 50 percent of its volumes that are exposed to frac spread at an average price of approximately \$35/Bbl.

AltaGas expects earnings in the Power segment to be higher in 2011 than 2010 as a result of higher prices and higher volumes generated. The addition of the new Harmattan cogeneration facility is expected to contribute to higher earnings in the power business throughout 2011. AltaGas has hedged approximately two-thirds of power exposed to Alberta power prices at an average price of \$70/MWh and approximately 50 percent at an average price of \$65/MWh for the third and fourth quarter 2011, respectively. For 2012, AltaGas is approximately one-third hedged at an average price of \$62.50/MWh. Recent supply uncertainty in the Alberta power market, together with changes to the Rate Regulated Option used for setting power prices by the utilities, has increased power prices and power price volatility. Management expects to execute short-term hedges throughout the year at premium prices to long-term prices as it has successfully done to date in 2011.

AltaGas also expects to report stronger earnings based on rate base growth in its Alberta and Nova Scotia natural gas distribution utilities, as rate base is expected to increase by 13 percent and 25 percent respectively in 2011.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2011 to be approximately \$525 million allocated approximately 50 percent for Gas, 40 percent for Power and 10 percent for Utilities. As at June 30, 2011, approximately \$515 million of capital has been committed for 2011.

AltaGas is well positioned to fund its committed capital program through its growing internally-generated cash flow, its dividend reinvestment plan and its continued strong access to capital markets. At June 30, 2011, the Corporation had \$890 million of available credit facilities.

AltaGas has made progress on several projects in support of its planned \$2 billion of organic growth in the next five years. AltaGas mitigates project cost escalation and schedule risk through its procurement and contracting strategies.

Northwest Hydroelectric Projects

Progress continued on the construction of the 195-MW Forrest Kerr run-of-river power generation project. The project includes tunnel excavation of a total of 4,870 linear meters. During second quarter 2011 excavation of the access tunnels has advanced as expected due to a stable and consistent rock formation. Currently, the total length of completed tunneling is in excess of 525 linear meters. The Forrest Kerr project is expected to be completed and operational by July 2014 for a total cost of approximately \$700 million. The Northwest Transmission Line (NTL) received Federal and Provincial Environmental Assessment Approvals as well as ratification by the Tahltan First Nation. AltaGas contributed an initial payment of \$2.7 million towards the construction and operation of the NTL.

AltaGas completed negotiations on two draft Impact Benefit Agreements (IBAs) with the Tahltan Central Council for the proposed 55-70MW McLymont Creek and 15-18MW Volcano Creek run-of-river projects located in Tahltan Nation traditional territory. The ratification vote by the Tahltan Nation on the proposed IBAs will take place September 9 to September 15, 2011. The two projects are estimated to cost approximately \$300 million and be in service in 2015 and 2016 respectively.

Harmattan Co-stream

The Harmattan Co-stream project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western System to be processed using spare capacity at the Harmattan complex to recover ethane and other NGLs. The project is expected to cost approximately \$130 million and is expected to commence operations in late first quarter 2012. Based on current capital cost estimates, AltaGas expects the annual EBITDA contribution to be in the range of \$20 million to \$25 million once completed.

During the first half of 2011, AltaGas ordered \$38 million of equipment and materials and completed pipeline surveys. Major equipment tie-in is planned to occur during the scheduled plant turnaround in September 2011. To date, approximately \$54 million of costs are fixed. AltaGas expects a further \$30 million to be fixed in third quarter 2011. In total, AltaGas expects approximately 65 percent of the total project cost to be contractually fixed. The remainder will be subject to cost and labour productivity risk. By the end of 2011, 85 percent of the costs will have been incurred.

In early January 2011, two of the parties that initially intervened in AltaGas' ERCB application filed notices of motion for leave to appeal the ERCB Decision at the Court of Appeal of Alberta. In late January, one of those parties filed an application with the ERCB for a Review and Variance of the ERCB Decision. The application with the ERCB for a Review and Variance of the ERCB Decision was dismissed by the ERCB on May 27, 2011. The leave to appeal applications were heard on June 8, 2011 and the decision is pending. AltaGas believes that the grounds set forth by the applicants for leave to appeal are without merit. AltaGas remains committed to the schedule as outlined above.

Gordondale Gas Plant

During the quarter, AltaGas received regulatory approval to construct a 120 Mmcf/d gas processing facility in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The plant will also be equipped with liquids extraction facilities. The facility and associated gas gathering system is expected to cost approximately \$235 million and be in service in late 2012. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility.

The first phase of the Gordondale gas plant will be using existing infrastructure in the area and building the Henderson pipeline to connect to the Pouce Coupe facility, AltaGas expects to provide processing services to Encana for early production of 15 Mmcf/d by late third quarter 2011.

During the first half of 2011, \$54 million of orders were placed for long-lead materials. Construction of the Henderson pipeline commenced May 24, 2011. AltaGas expects \$100 million of costs to be fixed by the end of September 2011. In total, approximately two thirds of costs are expected to be contractually fixed over the course of construction. The remainder will be subject to cost and labour productivity risk.

Harmattan Cogeneration #2

AltaGas plans to construct a second 15-MW cogeneration unit at the Harmattan complex as a means of supplying steam and power for the Co-stream project. The Cogeneration #2 project is estimated to cost \$24 million and be in service during second quarter 2012.

During the first half of 2011, purchase orders of approximately \$9 million for major equipment were placed resulting in \$12 million of costs being fixed to date. The application to Alberta Utilities Commission (AUC) was submitted in June 2011. Pending the project's approval, construction is scheduled to commence in third quarter 2011.

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. EBITDA and operating income exclude unrealized gains and losses for risk management contracts. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and its 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, operating income, EBITDA, adjusted net income and funds from operations throughout this document have the meanings as set out in this section.

Net revenue (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
		June 30		June 30
	2011	2010	2011	2010
Net revenue	113.7	124.8	251.4	252.0
Add: Cost of sales	254.4	209.2	520.1	442.5
Revenue (GAAP financial measure)	368.1	334.0	771.5	694.5

Net revenue, which is revenue 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 natural gas and power affect both revenue and cost of sales.

Operating income (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Operating income	34.3	35.6	92.7	73.0
Add (deduct):				
Unrealized gains (losses) on risk management contracts	(4.6)	3.8	(12.0)	9.1
Interest expense	(13.7)	(13.1)	(26.6)	(24.6)
Foreign exchange loss	-	-	-	(0.2)
Income tax (expense) recovery	3.3	2.1	(5.5)	7.5
Preferred share dividend (net of tax)	(2.8)	-	(5.5)	-
Net income applicable to common shares (GAAP financial measure)	16.6	28.4	43.1	64.8

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 by management to assess the operating performance of the business segments since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, interest expense, foreign exchange loss, income tax (expense) recovery and preferred share dividend (net of tax).

EBITDA (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
EBITDA	56.7	58.9	137.2	120.0
Add (deduct):				
Unrealized gains (losses) on risk management contracts	(4.6)	3.8	(12.0)	9.1
Amortization	(21.7)	(22.6)	(43.3)	(45.6)
Accretion of asset retirement obligations	(0.6)	(0.7)	(1.2)	(1.4)
Interest expense	(13.7)	(13.1)	(26.6)	(24.6)
Foreign exchange (loss) gain	-	-	-	(0.2)
Income tax (expense) recovery	3.3	2.1	(5.5)	7.5
Preferred share dividends (net of tax)	(2.8)	-	(5.5)	-
Net income applicable to common shares (GAAP financial measure)	16.6	28.4	43.1	64.8

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 how earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, 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, amortization, accretion of asset retirement obligations, interest expense, income tax (expense) recovery, and preferred share dividends (net of tax).

Adjusted net income (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Adjusted net income	20.0	25.6	52.0	58.0
Add (deduct): After-tax unrealized gain (loss) on risk management contracts	(3.4)	2.8	(8.9)	6.8
Net income applicable to common shares (GAAP financial measure)	16.6	28.4	43.1	64.8

Adjusted net income is a better reflection of actual business performance than net income since changes in value of risk management contracts are subject to end-of-period prices for equities, commodities, interest rates and foreign exchange. Management evaluates the overall performance of AltaGas' business prior to accounting for unrealized gains or losses from risk management activities. Adjusted net income is calculated from the Consolidated Statements of Income and is defined as net income applicable to common shares adjusted for after-tax unrealized gains or losses on risk management contracts.

Funds from operations (unaudited) (\$ millions)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Funds from operations	46.7	44.3	110.6	95.6
Add (deduct): Net change in non-cash working capital	4.1	(9.5)	(23.9)	(23.7)
Asset retirement obligations settled	(0.1)	-	(0.2)	(0.1)
Cash from operations (GAAP financial measure)	50.7	34.8	86.5	71.8

Funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in non-cash working capital in the period. 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 non-cash working capital and expenditures incurred to settle asset retirement obligations.

GAS

GAS OPERATING STATISTICS	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
E&T				
Extraction inlet gas processed (Mmcf/d) ⁽¹⁾	828	758	868	772
Extraction ethane volumes (Bbls/d) ⁽¹⁾	25,284	24,859	26,581	25,721
Extraction NGL volumes (Bbls/d) ⁽¹⁾	13,559	12,164	13,908	12,002
Total extraction volumes (Bbls/d) ⁽¹⁾	38,843	37,023	40,489	37,723
Frac spread - realized (\$/Bbl) ⁽¹⁾	36.65	27.51	34.50	28.92
Frac spread - average spot price (\$/Bbl) ^{(1) (2)}	41.27	31.06	41.09	33.16
FG&P				
Processing throughput (gross Mmcf/d) ⁽¹⁾	391	431	383	432
Capacity utilization (%) ⁽³⁾	33	37	33	37
Energy Services				
Average volumes transacted (GJ/d) ⁽⁴⁾	377,917	367,280	390,775	386,164

⁽¹⁾ Average for the period.

⁽²⁾ Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

⁽³⁾ As at the end of the reporting period.

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

During second quarter 2011, average ethane and NGL volumes in the extraction business increased by 425 Bbls/d and 1,395 Bbls/d respectively, compared to second quarter 2010. During first half of 2011, average ethane and NGL volumes increased by 860 Bbls/d and 1,906 Bbls/d, respectively, compared to the same period of 2010. Volumes were higher at most extraction facilities, led by increases at Younger due to higher inlet volumes, prior to its planned turnaround that commenced in June 2011 and Empress extraction facilities due to successful contracting efforts.

In FG&P, throughput in second quarter 2011 averaged 391 Mmcf/d compared to 431 Mmcf/d in same quarter 2010. Volumes were lower, despite the addition of the Marlboro gas processing plant and expansion of the Alder Flats facility which was completed at the end of April. Fires in the Slave Lake region reduced throughput by approximately 17 Mmcf/d over a 15-day period. There was no damage to AltaGas' facilities in the area. The lack of producer activity in response to low natural gas prices has resulted in overall lower average processing volumes of approximately 75 Mmcf/d from natural declines or well shut-ins during the first half of 2011 compared to the same period in 2010. During this same period, certain FG&P facilities, including the newly added Marlboro facility, saw an average increase of 25 Mmcf/d over the prior year period.

Overall, FG&P facilities processed an average of 16 Mmcf/d of natural gas more than first quarter 2011 and exited second quarter 2011 processing an average of 404 Mmcf/d.

Three Months Ended June 30

The Gas segment recorded operating income of \$25.2 million for second quarter 2011, a 29 percent increase compared to \$19.6 million for same quarter 2010.

In second quarter 2011, AltaGas acquired a 40 percent interest in the 40 Mmcf/d (gross) Marlboro gas processing facility (formerly referenced as Pine Creek). The Marlboro facility's capture area includes the newly discovered Wilrich and Notikewin zones. As well, the newly discovered Duvernay shale play also trends into an area six miles east of the plant. Contributions to operating income from this facility began in mid-May 2011.

During the quarter, Younger commenced its scheduled turnaround that occurs every three years and in conjunction with other operators in the area. The coordinated turnaround resulted in partial and full shutdowns during parts of June and July. Pursuant to the commercial terms covering the sale of natural gas liquids from Younger, the impact of the turnaround on operating income will not be recognized until third quarter 2011 and is expected to be approximately \$4 million.

Operating income increased due to higher frac margins and volumes, incremental contributions from new and expanded gas processing facilities, lower amortization and administrative costs and lower provision for doubtful customer accounts. These increases were partially offset by lower volumes processed at certain gas processing facilities, lower daily contract quantity on the Suffield system and lower margins realized in the natural gas storage business.

Net revenue in the Gas segment for second quarter 2011 was \$81.3 million compared to \$77.7 million for same period 2010. Net revenue increased largely due to higher realized frac exposed volumes and margins of \$5.1 million and lower bad debt provision of \$1.0 million. These increases were partially offset by lower gas processing volumes and fee-for-service revenues of \$1.5 million and lower transmission revenues of \$1.2 million which was driven largely by lower daily contract quantity on the Suffield system.

Operating and administrative expense in second quarter 2011 was \$41.8 million compared to \$41.9 million in second quarter 2010. Operating costs during the quarter decreased as a result of lower administration costs as a result of increased efficiencies and cost saving measures implemented. These decreases were partially offset by scheduled turnarounds at Younger and two other processing facilities and the addition or expansion of gas processing assets and variable costs associated with more extraction volumes.

Amortization expense in second quarter 2011 was \$13.7 million compared to \$15.5 million in second quarter 2010.

Accretion expense in second quarter 2011 was \$0.6 million compared to \$0.7 million in second quarter 2010. The decreases were due to revisions in estimates in the lives of certain facilities, partially offset by additional expenses associated with new or expanded facilities.

Six Months Ended June 30

The Gas segment reported operating income of \$55.4 million for first half 2011, a 31 percent increase compared to \$42.2 million for same period 2010.

Operating income increased due to higher frac exposed margins and volumes, the sale of the Groundbirch facility, settlement of a take-or-pay contract, contributions from new and expanded gas processing facilities, lower amortization and administration costs, higher fees earned from increased extraction volumes and lower provision for doubtful customer accounts. These increases were partially offset by lower volumes processed at some gas processing facilities, lower daily contract quantity on the Suffield system and lower margins realized in the natural gas storage business.

Net revenue in the Gas reporting segment for first half 2011 was \$169.1 million compared to \$157.6 million for same period 2010. Net revenue increased due the sale of the Groundbirch facility for a gain of approximately \$6 million and the settlement of a take-or-pay contract for \$2.0 million. In addition, net revenue increased by \$8.4 million due to higher frac exposed margins and volumes, \$1.3 million from higher operating expense recoveries, \$1.0 million from higher fees earned from increased extraction volumes and lower provision for doubtful accounts of \$1.0 million. These increases were partially offset by lower FG&P volumes and fee-for-service revenues of \$3.7 million, lower transmission revenues of \$2.7 million driven largely by lower daily contract quantity on the Suffield system and lower natural gas storage margins of \$2.0 million.

Operating and administrative expense for first half 2011 was \$85.2 million compared to \$82.8 million for same period 2010. Operating costs during the period increased as a result of gas processing assets that were added or expanded, scheduled turnarounds at Younger and two other processing facilities and variable costs associated with more extraction volumes. These increases were offset by lower administration costs as a result of increased efficiencies and cost saving measures implemented.

Amortization expense for the six months ended June 30, 2011, was \$27.4 million compared to \$31.1 million for the same period 2010. Accretion expense in first half 2011 was \$1.2 million compared to \$1.4 million in same period 2010. The decreases were due to revisions in estimates in the lives of certain facilities, partially offset by additional expenses associated with new or expanded facilities.

Gas Outlook

The Gas segment is expected to deliver stronger results in 2011 than in 2010. Stronger results are expected from the extraction and field gas processing assets as producers look to increase net backs from liquids-rich gas and higher realized frac spreads. These increases are expected to be partially offset by lower volumes in areas where there are fewer opportunities for producers to benefit from liquids-rich gas, lower daily contract quantity on the Suffield natural gas transmission system and lower margins in the storage business.

Throughput at extraction plants is expected to increase in 2011 over 2010 despite the scheduled turnarounds at the Harmattan and Younger facilities. Drilling activity in northeast British Columbia has increased as producers continue to develop tight and shale gas plays within the area. Developments in this area have resulted in higher volumes being processed at Younger. The new 25-kilometer, 16-inch diameter natural gas pipeline ("Septimus pipeline"), expected to be operational in fourth quarter 2011, will also contribute to higher volumes being processed at Younger. AltaGas has a 30 percent interest in the pipeline. Younger has undergone plant modifications during its turnaround in anticipation that throughput volumes will approach operating capacity of approximately 650 Mmcf/d by year end. Extraction volumes through AltaGas' other extraction facilities are also higher in response to producer drilling programs to access liquids-rich natural gas and the successful contracting of gas supply at the Empress plants.

AltaGas expects average annual volumes in 2011 to be higher than in 2010 within the field gathering and processing business as a result of prior year's projects to expand and modify certain existing facilities, recently acquired interest in the Marlboro plant and planned connection of the new Henderson pipeline to the Pouce Coupe plant. In addition, AltaGas' facilities within certain regions are experiencing higher activity levels as a result of producers' focus on high natural gas liquids content gas plays or light oil plays which create significant solution gas. 2011 operating income for the Gas business is also expected to be greater than 2010 due to \$2 million lower amortization than the prior year as a result of changes in expected lives at certain facilities.

Offsetting these gains will be the costs of turnarounds at the Younger and Harmattan facilities. The impact of the Younger turnaround on operating income of approximately \$4 million will not be recognized until the third quarter of 2011. Harmattan's turnaround is scheduled to commence in late September and continue into October which is expected to reduce operating income by \$7 million in 2011 compared to 2010. The financial impact of the turnarounds at the Younger and Harmattan facilities have increased by approximately \$2.5 million primarily as a result of higher volumes and frac spreads resulting in higher lost revenue than previously estimated. Lower daily contract quantity on the Suffield system is expected to lower operating income by \$6 million in 2011 compared to 2010.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve for 2011, management expects NGL frac spread prices to average approximately \$38/Bbl after deducting extraction premiums. In 2011, the Corporation estimates that 13 percent of total extraction volumes will be exposed to frac spread. For the remainder of 2011, approximately 65 percent of the exposure has been hedged at an average price of \$26.85/Bbl. For 2012, AltaGas has hedged approximately 50 percent of its volumes that are exposed to frac spread at an average price of \$35/Bbl.

POWER

POWER OPERATING STATISTICS

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Volume of power sold (GWh) ⁽¹⁾⁽²⁾	727	706	1,468	1,392
Average price realized on the sale of power (\$/MWh) ⁽¹⁾⁽²⁾	64.26	79.98	71.10	71.21
Alberta Power Pool average spot price (\$/MWh) ⁽¹⁾	52.12	80.56	67.73	60.72

⁽¹⁾ Average for the period.

⁽²⁾ Includes both Alberta and British Columbia sale of power.

Three Months Ended June 30

Operating income for second quarter 2011 was \$15.5 million compared to \$20.8 million for same period 2010. Operating income decreased as a result of lower realized spot power prices partially offset by the addition of the cogeneration facility at the Harmattan complex and stronger results from Bear Mountain. In second quarter 2011, AltaGas was two-thirds hedged in Alberta at an average price of \$67.47/MWh. In second quarter 2010, AltaGas was two-thirds hedged at an average price of \$73.99/MWh.

Net revenue for second quarter 2011 was \$23.0 million compared to \$27.7 million for same period 2010. The decrease was primarily due to lower realized power prices and higher transmission and environmental costs, partially offset by the addition of the Harmattan gas-fired cogeneration facility in fourth quarter 2010 and higher power generated at Bear Mountain.

Operating and administrative expense was \$3.4 million for second quarter 2011 compared to \$3.1 for same period 2010. The increase was primarily due to the addition of the Harmattan gas-fired cogeneration facility.

Amortization expense was \$4.1 million for second quarter 2011 compared to \$3.8 million for second quarter 2010. The increase was due to the addition of the Harmattan cogeneration facility.

Six Months Ended June 30

Operating income for first half 2011 was \$42.1 million compared to \$37.3 million for same period 2010. Operating income increased as a result of higher Alberta spot power prices, the addition of the cogeneration facility at the Harmattan complex and stronger results from Bear Mountain, partially offset by lower hedged volumes and hedged prices. For the first six months of 2011, AltaGas hedged 62 percent of power sold in Alberta at an average price of \$67/MWh compared to 65 percent hedges at \$71.57/MWh for same period 2010.

Net revenue for first half 2011 was \$56.7 million compared to \$51.2 million for same period 2010. Net revenue increased \$6.0 million due to higher Alberta spot power prices, \$3.4 million due to the addition of the Harmattan gas-fired cogeneration facility, \$1.9 million from Bear Mountain and \$1.6 million the gas-fired peaking plants, partially offset by \$7.6 million from lower hedged volumes and hedged prices.

Operating and administrative expense was \$6.5 million for first half 2011 compared to \$6.2 million in same period 2010. Amortization expense was \$8.1 million in first half 2011 compared to \$7.6 million in same period 2010. The increases were primarily due to the addition of the Harmattan cogeneration facility.

Power Outlook

The Power segment is expected to deliver stronger results in 2011 compared to 2010 as a result of higher prices and higher volumes generated. AltaGas has hedged approximately two-thirds of power exposed to Alberta power prices at an average price of \$70/MWh and approximately 50 percent at an average price of \$65/MWh for the third and fourth quarter 2011, respectively. For 2012, AltaGas is approximately one-third hedged at an average price of \$62.50/MWh. Recent supply uncertainty in the Alberta power market, together with changes to the rate-regulated option used for setting power prices by the Alberta utilities, have increased power prices and power price volatility. Management expects to execute short-term hedges throughout the year at premium prices to long-term prices as it has successfully done to date in 2011.

Current forward prices, as published in daily broker reports, are in the \$80s per MWh for third quarter 2011, \$70s per MWh for fourth quarter 2011 and \$60s per MWh for 2012. Higher power prices are expected to result in higher run times and availability of the gas-fired peakers resulting in higher energy and ancillary services sales in 2011 compared to 2010. The addition of the Harmattan cogeneration facility in late 2010 is also expected to contribute to stronger results.

UTILITIES

UTILITIES OPERATING STATISTICS

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Natural gas deliveries - end-use (PJ) ⁽¹⁾	3.7	3.3	13.0	10.5
Natural gas deliveries - transportation (PJ) ⁽¹⁾	1.2	1.4	2.5	2.7
Service sites ⁽²⁾	74,823	72,827	74,823	72,827
Degree day variance from prior period - AUI (%) ⁽³⁾	0.5	(10.7)	18.3	(17.0)
Degree day variance from prior period- Heritage Gas (%) ⁽³⁾	19.7	(15.4)	11.3	(13.3)

⁽¹⁾ Petajoule (PJ) is one million gigajoules (GJ).

⁽²⁾ Service sites reflect all of the service sites of AUI, Heritage Gas and Inuvik Gas.

⁽³⁾ Degree days relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations.

Three Months Ended June 30

The Utility segment is predominantly comprised of natural gas rate-regulated utilities, where net income is based on a regulated allowed return on capital invested. Rate-regulated cost-of-service entities such as AUI in Alberta and Heritage Gas in Nova Scotia generally collect operating and administrative costs, depreciation, interest expenses and income taxes paid in the rates charged to customers, and therefore changes in these costs do not normally impact the net income of the business. Consequently, this discussion of financial results focuses on net income.

Net income in the Utility segment is highly seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. Earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. Increases in the number of customers or changes in customer usage are examples of other factors that might typically affect volumes and hence earned returns.

Net income for second quarter 2011 was \$2.4 million compared to \$0.5 million for same period in 2010. Net income increased due to seasonal timing differences related to the recovery of cash income taxes in the year and other applied-for recoverable costs at AUI. Rate base growth of 28 percent at Heritage Gas and 13 percent at AUI also increased net income for second quarter 2011 as compared to 2010.

Six Months Ended June 30

Net income for first half 2011 was \$9.8 million compared to \$8.1 million for same period 2010. Net income increased \$1.6 million due to rate base growth of 13 percent and 28 percent at AUI and Heritage Gas, respectively, and \$1.2 million due to colder weather in Alberta and Nova Scotia in first half 2011 compared to same period 2010. These increases were partially offset by higher non-recoverable operating and administrative expenses.

Utilities Outlook

The Utility segment is expected to generate stronger earnings in 2011 based on rate base growth in its Alberta and Nova Scotia natural gas distribution utilities. In 2011, AUI is forecast to spend approximately \$26 million, growing mid-year rate base by 13 percent to \$153 million. Heritage Gas is forecasted to spend approximately \$19 million to expand its system in 2011 which, along with increases in the Revenue Deficiency Account (RDA), is expected to grow rate base by 25 percent.

AUI will continue to pursue growth in its existing franchise areas and is well positioned to capture opportunities arising in its service areas in Alberta. AUI expects that new business growth in 2011 will be approximately 2 percent.

AUC is currently considering AUI's rate application for 2010, 2011 and 2012. The hearing is scheduled for mid-October 2011 and a decision is expected in early 2012. In addition to increases in costs and capital spending, AUI is requesting approval of interest rates on all of its outstanding debt for the 3-year period. There is also a generic cost-of-capital proceeding currently underway to set return on equity for 2011 and 2012 for all utilities in Alberta. The unanticipated impact of decisions on these regulatory matters is recorded in the period in which the decision is received.

Heritage Gas expects growth in its franchise areas from the continued expansion of its system in the Halifax Regional Municipality and ongoing conversion of customers with existing access to natural gas. Heritage Gas expects to activate approximately 460 new customers in 2011.

The 13 percent return on equity and the 8.75 percent debt rate allowed at Heritage Gas are approved by the Nova Scotia Utility and Review Board (NSUAR) through 2011. Heritage Gas filed a General Tariff Application (GTA) on June 15, 2011 to apply for rates and terms beginning January 2012. The GTA requested 12.75 percent return on equity and 7.875 percent debt rate. The hearing is set for early fourth quarter 2011 and a decision from the NSUAR is expected before the end of 2011.

In December 2010, Inuvik Gas Ltd., a distribution company serving the Town of Inuvik in the Northwest Territories, and the Ikhil Joint Venture, holding natural gas reserves and related assets at Ikhil near the Town of Inuvik, in each of which AltaGas has a one third interest, announced their intention to perform repairs on a natural gas well as a result of natural gas deliverability issues. Repair work, which was concluded in March 2011, was not successful and the well was shut in. There is some uncertainty with respect to remaining reserves. AltaGas, as operator on behalf of the joint venture partners, is working with consultants to evaluate the reservoir and production options. Natural gas production from the second well at Ikhil continues to meet the demands of the Northwest Territories Power Corporation, a power supplier for areas of the Northwest Territories, and Inuvik Gas Ltd.

CORPORATE

Three Months Ended June 30

The operating loss for second quarter 2011 was \$11.4 million compared to \$8.8 million for second quarter 2010. Reported in the quarter is an unrealized loss of \$3.8 million on an equity investment compared to an unrealized loss of \$0.8 million in the same quarter last year.

Net revenue was in a negative position of \$3.5 million in second quarter 2011 compared to a negative position of \$0.4 million in same period 2010. The decrease was primarily due to an unrealized loss of \$3.8 million on an equity investment compared to an unrealized loss of \$0.8 million in the same quarter last year.

Operating and administrative expense was \$7.0 million in second quarter 2011 compared to \$7.7 million in second quarter 2010. Lower expenses were a result of cost saving initiatives implemented. Amortization expense was \$0.9 million in second quarter 2011 compared to \$0.7 million in the same quarter 2010.

Six Months Ended June 30

The operating loss for first half 2011 was \$21.5 million compared to \$17.3 million for same period 2010. Reported in first half 2011 is an unrealized loss of \$6.6 million on an equity investment compared to an unrealized loss of \$2.2 million in same period last year.

Net revenue was in a negative position of \$6.5 million in first half 2011 compared to a negative position of \$0.1 million in same period 2010. The decrease was mainly due to an unrealized loss of \$6.6 million on an equity investment compared to an unrealized loss of \$2.2 million in same period 2010.

Operating and administrative expense was \$13.2 million in first half 2011 compared to \$15.8 million in same period 2010. Lower expenses were a result of cost saving measures implemented and lower general and administrative costs primarily due to costs incurred in 2010 related to the IFRS conversion project, conversion to a corporation and Harmonized Sales Tax (HST) compliance costs. Amortization expense was \$1.8 million in first half 2011 compared to \$1.4 million in same period 2010.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2011 is expected to be lower than the loss reported in 2010. During 2010, AltaGas incurred costs to convert from a trust structure to a corporation and to support activities related to compliance with the HST in Ontario and British Columbia. AltaGas expects to incur costs to transition to US GAAP during 2011. The Corporate reporting segment also expects to report lower income from other investments during 2011.

AltaGas expects to report higher future income tax expense based on being a corporation for a full year and expects to incur an effective corporate tax rate of approximately 18 percent. The tax rate at the consolidated level is lower than the expected statutory rate as a result of the \$6.8 million decrease of future tax liabilities recorded in second quarter 2011 as well as the lower effective tax rate at the Utility segment. Future income taxes recoverable or payable by the Utilities are recorded as regulatory assets or liabilities until such time as the taxes are collectible or payable from or to the utility customers.

The effects of risk management contracts are based on estimates relating to commodity prices, interest rates and foreign exchange rates over time. The actual amounts will vary based on these drivers, and management is therefore unable to predict the impact of financial instruments on 2011 results. AltaGas does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During second quarter 2011, AltaGas increased capital assets, long-term investments and other assets by \$154.5 million compared to \$40.6 million in second quarter 2010.

Invested Capital - Investment Type	Three Months Ended June 30, 2011				
(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Capital assets	45.0	21.4	4.1	3.5	74.0
Energy services arrangements, contracts and relationships	-	87.3	-	-	87.3
Long-term investments and other assets	-	(0.1)	-	(6.7)	(6.8)
	45.0	108.6	4.1	(3.2)	154.5
Disposals:					
Capital assets	-	-	-	-	-
Long-term investments and other assets	-	-	-	(0.1)	(0.1)
Net Invested capital	45.0	108.6	4.1	(3.3)	154.4

Invested Capital - Investment Type	Three Months Ended June 30, 2010				
(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Capital assets	22.0	9.8	8.6	1.0	41.4
Long-term investments and other assets	0.3	-	-	(1.1)	(0.8)
	22.3	9.8	8.6	(0.1)	40.6
Disposals:					
Capital assets	-	-	-	-	-
Long-term investments and other assets	(2.1)	-	-	-	(2.1)
Net Invested capital	20.2	9.8	8.6	(0.1)	38.5

Invested Capital - Investment Type	Six Months Ended June 30, 2011				
(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Capital assets	70.8	50.6	8.8	5.3	135.5
Energy services arrangements, contracts and relationships	-	87.3	-	-	87.3
Long-term investments and other assets	-	(0.3)	-	(12.9)	(13.2)
	70.8	137.6	8.8	(7.6)	209.6
Disposals:					
Capital assets	(28.0)	-	-	-	(28.0)
Long-term investments and other assets	-	-	-	(0.5)	(0.5)
Net Invested capital	42.8	137.6	8.8	(8.1)	181.1

Invested Capital - Investment Type

Six Months Ended
June 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Capital assets	58.9	13.5	13.9	3.4	89.7
Long-term investments and other assets	0.3	(0.1)	-	(5.9)	(5.7)
	59.2	13.4	13.9	(2.5)	84.0
Disposals:					
Capital assets	(2.4)	-	-	-	(2.4)
Long-term investments and other assets	-	-	-	-	-
Net Invested capital	56.8	13.4	13.9	(2.5)	81.6

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

Growth capital of \$149.8 million was expended in second quarter 2011 (second quarter 2010 - \$37.8 million). In the Gas segment, growth capital comprised \$10.4 million for the Harmattan Co-stream project, \$10.5 million for the Gordondale gas plant and \$23.0 million for various Gas projects. Within the Power segment, growth capital included \$17.4 million related to the Forrest Kerr and \$1.1 million for other renewable power projects under development. The energy service arrangement for the Power segment increased by \$90.0 related to AltaGas' obligation to BC Hydro in support of the construction and operation of the Northwest Transmission Line. The Corporate segment reported a decrease of \$6.7 million related to the unrealized loss on mark-to-market for Alterra Power Corp. ("Alterra", previously Magma Energy Corporation).

Administrative and maintenance capital expenditures in second quarter 2011 were \$3.8 million and \$0.9 million, respectively (second quarter 2010 - \$1.0 million and \$1.8 million, respectively).

Growth capital of \$201.9 million was expended in the first half of 2011 (first half 2010 - \$77.9 million). In the Gas segment, growth capital was comprised of \$27.7 million for the Harmattan co-stream project, \$13.4 million for the Gordondale gas plant and \$27.4 million for various Gas-related projects. Within the Power segment, growth capital included \$33.5 million for Forrest Kerr and \$12.8 for other renewable power projects under development. The energy service arrangement for the Power segment increased by \$91.2, of which \$90.0 million related to AltaGas' obligation to BC Hydro in support of the construction and operation of the Northwest Transmission Line. The Corporate segment capital decreased by \$12.9 million due to unrealized loss for Alterra.

Administrative and maintenance capital expenditures in first half 2011 were \$5.9 million and \$1.8 million, respectively (first half 2010 - 3.0 million and \$3.1 million, respectively).

Invested Capital - Use

Three Months Ended
June 30, 2011

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	0.8	0.1	-	-	0.9
Growth	43.9	108.5	4.1	(6.7)	149.8
Administrative	0.3	-	-	3.5	3.8
Invested capital	45.0	108.6	4.1	(3.2)	154.5

Invested Capital - Use

Three Months Ended
June 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	0.4	1.4	-	-	1.8
Growth	21.9	8.4	8.6	(1.1)	37.8
Administrative	-	-	-	1.0	1.0
Invested capital	22.3	9.8	8.6	(0.1)	40.6

Invested Capital - Use

Six Months Ended
June 30, 2011

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	1.7	0.1	-	-	1.8
Growth	68.5	137.5	8.8	(12.9)	201.9
Administrative	0.6	-	-	5.3	5.9
Invested capital	70.8	137.6	8.8	(7.6)	209.6

Invested Capital - Use

Six Months Ended
June 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	1.1	2.0	-	-	3.1
Growth	58.1	11.4	13.9	(5.5)	77.9
Administrative	-	-	-	3.0	3.0
Invested capital	59.2	13.4	13.9	(2.5)	84.0

FINANCIAL INSTRUMENTS

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During second quarter 2011, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 7 of the interim Consolidated Financial Statements:

- **Commodity forward contracts:** The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock-in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services business transacts primarily on this basis.
- **Commodity swap contracts:** 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 business results are significantly 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 \$999.99/MWh in second quarter 2011 and \$2.40/MWh to \$999.99/MWh in same quarter last year. The average Alberta spot price was \$52.12/MWh in second quarter 2011 (second quarter 2010 - \$80.56/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average price realized for power by AltaGas was \$64.26/MWh in second quarter (second quarter 2010 - \$79.98/MWh). AltaGas has hedged approximately two-thirds of power exposed to Alberta power prices at an average price of \$70/MWh and approximately 50 percent at an average price of \$65/MWh for the third and fourth quarter 2011, respectively. For 2012, AltaGas is approximately one-third hedged at an average price of \$62.50/MWh.

- NGL frac spread hedges: The Corporation executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The E&T business results are affected by fluctuations in NGL frac spreads. During the second quarter 2011, the Corporation had NGL frac spread agreements for an average of 3,625 Bbls/d at an average price of \$26.85/Bbl. The average spot NGL frac spread for second quarter 2011 was \$41.27/Bbl (second quarter 2010 - \$31.06/Bbl). The average NGL frac spread realized by AltaGas in second quarter 2011 was \$36.65/Bbl (second quarter 2010 - \$27.51/Bbl). The Corporation has hedged an average of 3,625 Bbls/d, or approximately 65 percent of volumes that are exposed to spot prices for the remainder of 2011, at an average price of \$26.85/Bbl. For 2012, AltaGas has hedged approximately 50 percent of its volumes that are exposed to frac spread at an average price of \$35/Bbl.
- Interest rate forward contracts: The Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At June 30, 2011, the Corporation had interest rate swaps for \$80 million with varying terms to maturity until March 31, 2012. At June 30, 2011, the Corporation had fixed the interest rate on 100 percent of its debt including MTNs and capital leases (December 2010 - 96 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.

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

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

LIQUIDITY

AltaGas does not expect any currently known trend or uncertainty to affect its ability to access its historical sources of funding. On March 24, 2011, AltaGas issued \$200 million in Medium-Term Notes (MTNs) with a coupon rate of 4.10 percent maturing on March 24, 2016.

On April 26, 2011, AltaGas entered into an agreement for a new \$125 million letter of credit demand facility. AltaGas may borrow by way of letter of credit only under the new credit facility.

On May 30, 2011, AltaGas amended and extended its \$600 million unsecured revolving credit facility with a syndicate of Canadian chartered banks. The credit facility contains a \$200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of \$800 million. The credit facility's term was extended to four years with a new maturity date of May 30, 2015.

On May 30, 2011, AltaGas amended and extended its \$75 million extendible revolving term credit facility with two Canadian chartered banks. The credit facility's term was extended to four years with a new maturity date of May 30, 2015.

Cash Flows	Three Months Ended		Six Months Ended	
		June 30		June 30
(\$ millions)	2011	2010	2011	2010
Cash from operations	50.7	34.8	86.5	71.8
Investing activities	(76.2)	(28.8)	(123.1)	(57.2)
Financing activities	(75.2)	(11.4)	45.0	(17.5)
Change in cash	(100.7)	(5.4)	8.4	(2.9)

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was \$50.7 million in second quarter 2011 compared to \$34.8 million in second quarter 2010. The increase in cash from operations was primarily a result of higher earnings and higher non-cash working capital. Higher net change in non-cash working capital was driven by lower inventory.

Working Capital	June 30	June 30
(\$ millions except current ratio)	2011	2010
Current assets	294.8	302.2
Current liabilities	394.8	456.6
Working capital	(100.0)	(154.4)
Current ratio	0.75	0.66

Working capital was in a deficit position of \$100.0 million at June 30, 2011, compared to a deficit position of \$154.4 million at June 30, 2010. The working capital ratio was 0.75 at second quarter 2011 compared to 0.66 at second quarter 2010. The working capital ratio increased due to a decrease in current portion of long-term debt and an increase in accounts receivable and higher cash balance as of June 30, 2011. The increase was partially offset by higher accounts payables and decreases in short-term investment and risk management assets.

Investing Activities

Cash used for investing activities in second quarter 2011 was \$76.2 million compared to \$28.8 million in second quarter 2010. Investing activities in the quarter were mainly comprised of capital asset expenditures of \$85.5 million and a change in restricted cash holdings of \$3.5 million, partially offset by proceeds of \$13.4 million on the sale of an asset.

Financing Activities

Cash used for financing activities was \$75.2 million in second quarter 2011 compared to cash used for financing activities of \$11.4 million in second quarter 2010. The net change in cash was due to the repayment of long-term debt in second quarter 2011 compared to the net issuance of long-term debt in same period 2010 as well as lower payout to shareholders in second quarter 2011.

CAPITAL RESOURCES

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. At June 30, 2011, AltaGas had total debt outstanding of \$991.8 million, up from \$904.5 million at December 31, 2010. At June 30, 2011, AltaGas had \$975.0 million in MTNs outstanding and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances and letters of credit through bank lines amounting to \$1,071 million. At June 30, 2011, AltaGas had drawn bank debt of \$1.5 million and letters of credit outstanding of \$179.5 million against the extendible revolving letter of credit facility, the syndicated credit facilities and the demand operating facilities. As at June 30, 2011, the Corporation had \$890 million in available credit facilities and \$10.6 million in cash and cash equivalents.

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.

At June 30, 2011, AltaGas' current portion of long-term debt was \$105.9 million. The Corporation has a \$100 million MTN maturing in January of 2012.

AltaGas' earnings interest coverage for the rolling 12 months ended June 30, 2011 was 2.10 times.

Credit facilities (\$ millions)	Borrowing capacity	Drawn at June 30 2011	Drawn at December 31 2010
Demand operating facilities	196.0	121.7	7.9
Extendible revolving letter of credit facility	75.0	59.3	50.5
Syndicated revolving credit facility ⁽¹⁾	600.0	-	-
Utility Group revolving credit facility ⁽²⁾	200.0	-	114.5
	1,071.0	181.0	172.9

⁽¹⁾ Revolving credit facility maturing May 30, 2015.

⁽²⁾ Revolving credit facility maturing November 17, 2013.

At June 30, 2011, AltaGas held a \$75 million (December 31, 2010 - \$75.0 million) unsecured 4-year extendible revolving letter of credit facility with two Canadian chartered banks maturing on May 30, 2015. AltaGas may also borrow by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At June 30, 2011, AltaGas had letters of credit of \$59.3 million (December 31, 2010 - \$50.5 million) outstanding against the extendible revolving letter of credit facility. As at June 30, 2011, AltaGas held \$196 million (December 31, 2010 - \$71 million) in demand operating and demand letter of credit facilities. As at June 30, 2011, AltaGas had draws and letters of credit of \$121.7 million (December 31, 2010 - \$7.9 million) outstanding against the demand facilities.

The Utility Group has a \$200 million, three-year revolving credit facility maturing on November 17, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At June 30, 2011, AltaGas did not have any debt outstanding (December 31, 2010 - \$114.5 million) under the Utility Group facility.

RELATED PARTIES

AltaGas pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is partially owned by an employee of AltaGas. Payments of \$23 thousand were made in second quarter 2011 (second quarter 2010 - \$22 thousand) which is the exchange value of the property agreed to by both parties. The lease expires December 2011.

SHARE INFORMATION

At June 30, 2011, AltaGas had 83.4 million common shares outstanding and a market capitalization of \$2.1 billion based on a closing trading price on June 30, 2011, of \$25.75 per share. At June 30, 2011, there were 4.6 million options outstanding and 1.6 million options exercisable under the terms of the share option plan.

DIVIDENDS AND DISTRIBUTIONS

Since the corporate conversion effective July 1, 2010, AltaGas Ltd. declares and pays a monthly dividend to its shareholders. AltaGas dividends are determined by giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements. In second quarter 2011, AltaGas declared dividends of \$27.5 million (second quarter 2010 distributions - \$41.7 million).

For first half 2011, AltaGas declared dividends of \$54.8 million. Prior to corporate conversion, for the six months ended June 30, 2010, AltaGas declared distributions of \$84.7 million.

The following table summarizes AltaGas' quarterly distribution and dividend declaration for 2010 and 2011:

Distributions/Dividends

Years ended December 31

(\$ per share or unit)	2011	2010
First quarter	0.33	0.54
Second quarter	0.33	0.54
Third quarter ⁽¹⁾	-	0.33
Fourth quarter	-	0.33
Total	0.66	1.74

⁽¹⁾ As of July 1, 2010, after AltaGas' conversion to a corporation, monthly dividends are declared to its shareholders.

NON-MONETARY TRANSACTION

AltaGas has entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs were created through the generation of power at Bear Mountain between 2009 and 2010. The verified emission offsets received by AltaGas were used to offset the costs to comply with Specified Gas Emitters Regulation (SGER) in 2010. The contract was completed in second quarter 2010.

SUBSEQUENT EVENT

On July 4, 2011, AltaGas was granted exemptive relief by the Alberta Securities Commission to prepare its financial statements in accordance with US GAAP without being registered with the SEC.

CHANGES IN ACCOUNTING POLICIES

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

The Accounting Standards Board (AcSB) confirmed in February 2008 that International Financial Reporting Standards (IFRS) will replace Canadian Generally Accepted Accounting Principles (CGAAP) for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

On September 10, 2010, AcSB amended the introduction to Part I of the CICA Handbook - Accounting - to permit, but not to require qualifying entities with Rate-Regulated Activities (RRA) to adopt IFRS for the first time no later than interim and annual financial statements relating to annual periods beginning on or after January 1, 2012, thereby providing a 1-year deferral.

AltaGas is a qualified entity for the deferral period permitted by AcSB, based on the activities of AUI and Heritage Gas. AltaGas has elected to use the deferral offered by the AcSB given the uncertainty with respect to the application of IFRS to the RRA. AltaGas has reassessed the accounting policy choices available and determined that the most appropriate decision for AltaGas' business activities is the use of US GAAP effective January 1, 2012.

US GAAP reporting is generally permitted by Canadian securities laws and Toronto Stock Exchange for companies subject to reporting obligations under US securities laws (ref. NI 52-107 Acceptable Accounting Principles and Auditing Standards). On July 4, 2011, AltaGas was granted exemptive relief by the Alberta Securities Commission from the NI 52-107 rules, to prepare its financial statements in accordance with US GAAP without being registered with the SEC. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

AltaGas commenced a process to transition from Canadian GAAP to US GAAP establishing a project team to plan for and achieve a smooth transition to US GAAP. Management provides regular progress reports to the Audit Committee of the Board of Directors on the status of the US GAAP implementation project.

The US GAAP project consists of six phases, which in certain cases will be in process concurrently:

- Scoping phase – This phase identified key areas impacted by the transition to US GAAP and identified the standards and interpretations applicable to AltaGas. This phase was completed in January 2011 as part of the process for determining the most appropriate accounting choice.
- Diagnostic phase – In this phase, each standard and interpretation was assessed to identify the changes required in the existing accounting policies, information systems and business processes. This phase was completed in March 2011.
- Design and planning phase – Available alternatives in the accounting policies are assessed and adopted retrospectively to the dates when the US requirements became effective. This phase is still in progress and will determine the opening balances of the statement of financial position at January 1, 2011.
- Solution development phase – Based on the adopted accounting policies, the project team defines and develops systems, processes and training required for the implementation of US GAAP. This phase is planned to be completed by September 30, 2011.
- Implementation phase – During the implementation phase, changes in accounting policies and procedures are executed and tested. Financial information in accordance with US GAAP is collected, enabling the comparative reporting in 2012. Where appropriate, processes to support the CEO/CFO certification will be modified. Training is provided to support US GAAP conversion. This phase will be completed in early 2012.
- Post-implementation phase – US GAAP financial statements will be prepared for each reporting period starting from Q1 2012.

External auditors have been engaged to provide their opinion on the compliance of the financial statements with US GAAP requirements for an opening statement of financial position at January 1, 2011 and for the review of the interim financial results throughout 2011.

SIGNIFICANT ACCOUNTING POLICIES

AltaGas' significant accounting policies remain unchanged from December 31, 2010. For further information regarding these policies refer to the notes to the audited Consolidated Financial Statements in AltaGas' 2010 Annual Report.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of 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 amortization expense, asset retirement obligations, asset impairment assessment, income taxes, pension and rate-regulated assets and liabilities. For a full discussion of these accounting estimates, refer to the MD&A in AltaGas' 2010 Annual Report and the notes to the interim Consolidated Financial Statements for the six months ended June 30, 2011.

OFF-BALANCE SHEET ARRANGEMENTS

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

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

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

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of AltaGas employees, DC&P and ICFR to provide reasonable assurance that material information relating to AltaGas' business is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with Canadian GAAP.

During the second quarter 2011, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

(\$ millions)	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09	Q3-09
Total revenue	368.1	403.4	362.2	297.4	334.0	360.5	336.4	291.4
Net revenue ⁽¹⁾	113.7	137.7	130.7	102.6	124.8	127.2	115.4	114.7
Operating income ⁽¹⁾	34.3	58.5	47.6	32.6	35.6	37.4	46.0	41.0
Net income applicable to common shares	16.6	26.6	26.5	6.0	28.4	36.4	32.1	34.7
(\$ per share)	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09	Q3-09
Net income applicable to common shares								
Basic	0.20	0.32	0.32	0.07	0.35	0.45	0.40	0.44
Diluted	0.20	0.31	0.32	0.07	0.35	0.45	0.40	0.43
Distributions / dividends declared	0.33	0.33	0.33	0.33	0.54	0.54	0.54	0.54

⁽¹⁾ 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:

- During 2009, AltaGas had adjusted liabilities related to natural gas transactions within energy services resulting in a one-time revenue impact of \$9.2 million;
- During fourth quarter 2009, Bear Mountain was fully connected to the B.C. power grid and met the conditions for commercial operations in order to receive the firm price under the 25-year EPA with BC Hydro;
- During fourth quarter 2009, AltaGas acquired all the outstanding common shares of Utility Group not previously held by AltaGas for \$204.5 million including assumed debt;
- During fourth quarter 2009, AltaGas acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas for \$110.7 million;
- During first quarter 2010, AltaGas acquired all the outstanding common shares of Landis Energy Corporation for \$25.6 million;
- On July 1, 2010, AltaGas converted from an income trust to a corporation resulting in AltaGas being taxable as a corporation;
- In third quarter 2010, AltaGas reported \$21.1 million lower revenue as a result of mark-to-market accounting;
- In fourth quarter 2010, AltaGas completed the construction of a 15-MW gas-fired cogeneration facility at the Harmattan Complex;
- In first quarter 2011, AltaGas accepted an offer from a producer to sell the Groundbirch facility. The offer allowed the Corporation to realize a pre-tax gain of approximately \$6 million on the disposition;
- Results in first quarter 2011 were impacted by a settlement of a take-or-pay arrangement resulting in early recognition of pre-tax earnings of \$2 million; and
- In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflects the substantively enacted tax rates anticipated to be in effect in the periods in which the differences are expected to reverse with a decrease of \$6.8 million to future income tax liabilities.

Consolidated Balance Sheets

(unaudited)

(\$ thousands)	June 30 2011	December 31 2010
ASSETS		
Current assets		
Cash and cash equivalents	\$ 10,550	\$ 2,109
Accounts receivable	215,039	224,370
Inventory	1,523	13,107
Restricted cash holdings from customers	19,416	17,624
Regulatory assets	298	2
Risk management	40,441	41,226
Prepaid expense and other current assets	7,548	5,587
	294,815	304,025
Capital assets	2,065,216	1,995,632
Energy arrangements, contracts and relationships	207,024	120,848
Goodwill	199,497	199,497
Regulatory assets	81,042	76,515
Risk management	19,963	22,587
Long-term investments and other assets <i>(note 7)</i>	18,238	32,588
	\$ 2,885,795	\$ 2,751,692
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 198,948	\$ 228,772
Dividends payable	9,173	9,078
Short-term debt	4,287	9,478
Current portion of long-term debt <i>(note 5)</i>	105,886	1,508
Customer deposits	23,004	21,432
Regulatory liabilities	2,220	1,494
Risk management	44,585	39,209
Other current liabilities	6,723	12,302
	394,826	323,273
Long-term debt <i>(note 5)</i>	881,602	893,498
Asset retirement obligations	40,536	39,516
Future income taxes	236,852	233,763
Regulatory liabilities	19,608	18,518
Risk management	19,654	20,598
Other long-term liabilities <i>(note 8)</i>	69,320	20
Future employee obligations	12,282	11,475
	1,674,680	1,540,661
Shareholders' equity	1,211,115	1,211,031
	\$ 2,885,795	\$ 2,751,692

See accompanying notes to the unaudited Consolidated Financial Statements.

Consolidated Statements of Income

(unaudited)

	Three Months Ended		Six Months Ended	
	June 30		June 30	
<i>(\$ thousands except per share amounts)</i>	2011	2010	2011	2010
REVENUE				
Operating	\$ 376,173	\$ 330,608	\$ 790,044	\$ 685,565
Unrealized gain (loss) on risk management contracts <i>(note 7)</i>	(4,555)	3,829	(11,983)	9,112
Other revenue	(3,532)	(400)	(6,543)	(144)
	368,086	334,037	771,518	694,533
EXPENSES				
Cost of sales	254,407	209,176	520,104	442,466
Operating and administrative	61,661	62,131	126,136	122,922
Accretion of asset retirement obligations	608	725	1,216	1,445
Amortization:				
Capital assets	19,131	20,154	38,305	40,629
Energy arrangements, contracts and relationships	2,543	2,491	5,035	4,982
	338,350	294,677	690,796	612,444
Foreign exchange loss (gain)	49	(39)	12	209
Interest expense				
Short-term debt	1,484	479	2,912	885
Long-term debt	12,230	12,608	23,706	23,703
Income before income taxes	15,973	26,312	54,092	57,292
Income tax expense (recovery)				
Current	120	1,706	1,316	489
Future	(3,466)	(3,759)	4,156	(7,958)
Net income	19,319	28,365	48,620	64,761
Preferred share dividends (net of tax)	2,750	-	5,500	-
Net income applicable to common shares	\$ 16,569	\$ 28,365	\$ 43,120	\$ 64,761
Net income per share <i>(note 10)</i>				
Basic	\$ 0.20	\$ 0.35	\$ 0.52	\$ 0.80
Diluted	\$ 0.20	\$ 0.35	\$ 0.51	\$ 0.80
Weighted average number of shares outstanding (thousands) <i>(notes 9 and 10)</i>				
Basic	83,171	81,354	82,963	81,069
Diluted	84,239	81,604	83,925	81,347

See accompanying notes to the unaudited Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive (Loss) Income

(unaudited)

<i>(\$ thousands)</i>	Three Months Ended		Six Months Ended	
	2011	June 30 2010	2011	June 30 2010
Net income	\$ 19,319	\$ 28,365	\$ 48,620	\$ 64,761
Other comprehensive income (loss), net of tax				
Unrealized net (loss) on available-for-sale financial assets	(3,063)	(1,089)	(5,229)	(3,396)
Unrealized net gain (loss) gain on derivatives designated as cash flow hedges	(2,814)	(3,822)	(2,405)	(6,012)
Reclassification to net income of net gain on derivatives designated as cash flow hedges pertaining to prior periods	155	(2,597)	565	(8,870)
	(5,722)	(7,508)	(7,069)	(18,278)
Comprehensive income	\$ 13,597	\$ 20,857	\$ 41,551	\$ 46,483
Accumulated other comprehensive (loss) income, beginning of period	\$ (4,099)	\$ 10,455	\$ (2,752)	\$ 21,225
Other comprehensive loss, net of tax	(5,722)	(7,508)	(7,069)	(18,278)
Accumulated other comprehensive (loss) income, end of period <i>(note 7)</i>	\$ (9,821)	\$ 2,947	\$ (9,821)	\$ 2,947

See accompanying notes to the unaudited Consolidated Financial Statements.

Consolidated Statements of Shareholders' Equity

(unaudited)

Six Months Ended

June 30

<i>(\$ thousands)</i>	2011	2010
Common shares		
Balance, beginning of period	\$ 1,023,033	\$ 982,662
Shares issued for cash on exercise of options	2,497	738
Shares issued under DRIP ⁽¹⁾	16,813	18,928
Shares issued on exercise of warrants	-	3,394
Balance, end of period	1,042,343	1,005,722
Preferred shares		
Balance, beginning of period	194,126	-
Balance, end of period	194,126	-
Contributed surplus		
Balance, beginning of period	5,672	5,621
Amortization of share options	869	195
Exercise of share options	(1,202)	(175)
Cancellation of share options	(147)	-
Other adjustments	-	1,106
Balance, end of period	5,192	6,747
Warrants		
Balance, beginning of period	-	4,500
Exercised	-	(4,500)
Balance, end of period	-	-
Accumulated earnings		
Balance, beginning of period	(9,048)	34,849
Net income	48,620	64,761
Distributions	-	(84,734)
Common share dividends	(54,797)	-
Preferred share dividends (net of tax)	(5,500)	-
Balance, end of period	(20,725)	14,876
Accumulated other comprehensive (loss) income		
Balance, beginning of period	(2,752)	21,225
Other comprehensive loss	(7,069)	(18,278)
Balance, end of period	(9,821)	2,947
Total shareholders' equity	\$ 1,211,115	\$ 1,030,292

⁽¹⁾ Dividend Reinvestment and Optional Share Purchase Plan.

See accompanying notes to the unaudited Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(unaudited)

(\$ thousands)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Cash from operations				
Net income	\$ 19,319	\$ 28,365	\$ 48,620	\$ 64,761
Items not involving cash:				
Amortization	21,674	22,645	43,340	45,611
Accretion of asset retirement obligations	608	725	1,216	1,445
Share-based compensation	(350)	59	(481)	19
Future income tax expense (recovery)	(3,466)	(3,759)	4,156	(7,958)
(Gain) on sale of assets	-	(459)	(6,172)	(1,855)
Unrealized (gains) losses on risk management contracts	4,555	(3,829)	11,982	(9,112)
Unrealized losses (gains) on held-for-trading investments	3,798	767	6,560	2,151
Other	516	93	1,410	1,222
Non-operating investment income	-	(338)	-	(683)
Asset retirement obligations settled	(61)	(29)	(195)	(95)
Net change in non-cash working capital <i>(note 12)</i>	4,121	(9,481)	(23,903)	(23,705)
	50,714	34,759	86,533	71,801
Investing activities				
Change in restricted cash holdings from customers	(3,541)	197	(1,792)	1,967
Capital expenditures	(85,464)	(25,891)	(131,556)	(40,129)
Disposition of capital assets	13,400	-	13,400	-
Acquisition of energy services arrangements, contracts and relationships	36	539	(3,924)	(539)
Investment in regulatory assets	(572)	(3,973)	578	(3,887)
Distributions from equity investments	(15)	119	186	119
Disposition of short-term investments	-	338	-	683
Income from short-term investment	-	-	-	4,716
Business acquisition	-	(802)	-	(22,719)
Disposition of long-term investments and other assets	-	2,021	-	2,871
	(76,156)	(28,771)	(123,108)	(57,159)
Financing activities				
Issuance (repayment) of short-term debt	3,447	(18,085)	(5,190)	(13,752)
Net issuance (repayment) of revolving long-term debt	(54,699)	54,356	(105,555)	(120,980)
Net issuance (repayment) of long-term debt	(850)	(666)	198,038	198,069
Dividends and distributions	(30,873)	(56,957)	(61,702)	(100,496)
Net proceeds from issuance of common shares	7,784	9,935	19,425	19,666
	(75,191)	(11,417)	45,016	(17,493)
Change in cash and cash equivalents	(100,633)	(5,429)	8,441	(2,851)
Cash and cash equivalents, beginning of period	111,183	6,317	2,109	3,739
Cash and cash equivalents, end of period	\$ 10,550	\$ 888	\$ 10,550	\$ 888

See accompanying notes to the unaudited Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(unaudited)

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

1. STRUCTURE OF ALTAGAS LTD.

On July 1, 2010 AltaGas Ltd. (AltaGas or the Corporation) completed the conversion from an income trust to a corporation pursuant to a plan of arrangement (the Arrangement) under the Canadian Business Corporations Act. Pursuant to the Arrangement, securityholders exchanged each trust unit and exchangeable unit for common shares of AltaGas Ltd. on a one-for-one basis.

The unaudited interim Consolidated Financial Statements follow the continuity of interest basis of accounting whereby the Corporation is considered a continuation of AltaGas Income Trust (the Trust). As a result, the comparative consolidated financial statements include the Trust's results for the period up to and including June 30, 2010 and the Corporation's results of operations thereafter. All references to shares and shareholders in the consolidated financial statements and notes pertain to common shares and common shareholders subsequent to the conversion and units and unitholders prior to the conversion.

2. BASIS OF PRESENTATION

The unaudited interim Consolidated Financial Statements of AltaGas Ltd. include the accounts of the Corporation and all of its wholly owned subsidiaries, and its proportionate interest in various partnerships and joint ventures including the Edmonton Ethane Extraction Plant, Empress ATCO Extraction Plant, Empress Provident Extraction Plant, Younger Extraction Plant, Sarnia Airport Storage Pool Limited, Alton Natural Gas Storage, ASTC Power Partnership (ASTC), Inuvik Gas Ltd. (Inuvik Gas) and Ikhil Joint Venture. Transactions between AltaGas Ltd. and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

The unaudited interim Consolidated Financial Statements have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles (CGAAP). The accounting policies applied are consistent with those outlined in the Corporation's annual Consolidated Financial Statements for the year ended December 31, 2010. These unaudited interim Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2010 audited Consolidated Financial Statements included in AltaGas' Annual Report.

3. UPDATE TO SUMMARY OF ACCOUNTING POLICIES

Inventory

Inventory consists of materials, supplies, natural gas liquids (NGL) and proprietary natural gas held in storage. Materials, supplies and NGL inventories are valued at the lower of cost or net realizable value. Cost of inventories is assigned using a weighted average cost formula.

AltaGas has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. As a result, proprietary natural gas held in storage is carried at fair value based on published market prices as at the balance sheet date less costs to sell. All changes in fair value of proprietary natural gas held in storage are recognized in inventory and unrealized gains or losses on risk management.

Capital assets and amortization

In third quarter 2010, AltaGas revised the estimated useful lives of the Corporation's capital assets due to updated reservoir engineering studies, which directly affects reserve lives and therefore the expected useful lives of facilities within those locations. The result of the assessment is an increase in the useful lives of some facilities and a reduction in the useful lives of other facilities.

The Corporation continues to amortize the cost of capital assets, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of regulated natural gas distribution assets, where amortization is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

The updated range of useful lives for AltaGas' capital assets as a result of the change in estimate is as follows:

<i>Gas</i>	
Extraction and transmission (E&T)	15 - 40 years
Field gathering and processing (FG&P)	15 - 36 years
Energy services	19 years
Natural Gas Storage	20 - 50 years
Other	1- 32 years
 <i>Power</i>	
Assets under capital lease	10 years
Power generation assets	20 - 30 years
 <i>Utilities</i>	
Utilities assets	0.85 - 23.82 percent
 <i>Corporate</i>	
Other assets	1 - 5 years

The change in estimated useful lives was accounted for on a prospective basis from July 1, 2010.

4. FUTURE ACCOUNTING CHANGES

Section 1582 "Business Combinations"

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. CICA Handbook Section 1582 replaced Section 1581 "Business Combinations" establishing standards for the accounting for a business combination. Earlier adoption of this section was permitted but AltaGas elected not to early adopt.

Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-Controlling Interests"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbook Sections 1601 and 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination.

International Financial Reporting Standards (IFRS)

The Accounting Standards Board (AcSB) confirmed in February 2008 that International Financial Reporting Standards (IFRS) will replace Canadian Generally Accepted Accounting Principles (CGAAP) for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

On September 10, 2010, AcSB amended the introduction to Part I of the CICA Handbook - Accounting - to permit, but not to require qualifying entities with Rate-Regulated Activities (RRA) to adopt IFRS for the first time no later than interim and annual financial statements relating to annual periods beginning on or after January 1, 2012, thereby providing a 1-year deferral.

AltaGas is a qualified entity for the deferral period permitted by AcSB, based on the activities of AUI and Heritage Gas. AltaGas has elected to use the deferral offered by the AcSB given the uncertainty with respect to the application of IFRS to the RRA. AltaGas has reassessed the accounting policy choices available and determined that the most appropriate decision for AltaGas' business activities is the use of US GAAP effective January 1, 2012.

US GAAP reporting is generally permitted by Canadian securities laws and Toronto Stock Exchange for companies subject to reporting obligations under US securities laws (ref. NI 52-107 Acceptable Accounting Principles and Auditing Standards). On July 4, 2011, AltaGas was granted exemptive relief by the Alberta Securities Commission from the NI 52-107 rules, to prepare its financial statements in accordance with US GAAP without being registered with the SEC. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

AltaGas commenced a process to transition from Canadian GAAP to US GAAP establishing a project team to plan for and achieve a smooth transition to US GAAP. Management provides regular progress reports to the Audit Committee of the Board of Directors on the status of the US GAAP implementation project.

5. LONG-TERM DEBT

	June 30 2011	December 31 2010
Credit facilities	\$ 4,320	\$ 113,789
Medium-term notes	975,000	775,000
Loan from Province of Nova Scotia	4,675	4,535
Capital lease obligations	5,342	6,076
Promissory note	4,325	-
Other long-term debt	677	807
Unamortized deferred financing	(6,851)	(5,201)
	987,488	895,006
Less current portion	105,886	1,508
	\$ 881,602	\$ 893,498

Credit Facilities

At June 30, 2011, AltaGas held a \$600 million unsecured extendible revolving four-year credit facility with a syndicate of Canadian chartered banks. The credit facility contains a \$200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of \$800 million. This credit facility was used to retire and replace the previously held \$150 million and \$375 million credit facilities which matured in August and September 30, 2010, respectively. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances of letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. On May 30, 2011, AltaGas amended and extended the credit facility agreement to four years with a new maturity date of May 30, 2015.

On December 13, 2010, AltaGas entered into a promissory note agreement with the Toronto Dominion Bank as lender. On January 17, 2011, the lender advanced the available funds under the promissory note agreement. The financing arrangement was used to fund the purchase of some of the equipment required in connection with the first Harmattan cogeneration project.

On November 17, 2010, AltaGas restated and amended the Utility Group's maturing \$130 million unsecured extendible revolving credit facility. Through a syndicate of five banks, this facility was increased to \$200 million and its term was extended by three years to mature on November 17, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At June 30, 2011, AltaGas did not have any debt outstanding (December 31, 2010 - \$114.5 million) under the Utility Group facility.

Medium-Term Notes

On January 19, 2007, AltaGas issued \$100 million of 5.07 percent senior unsecured MTNs. The notes mature on January 19, 2012.

On April 29, 2009, AltaGas issued \$200 million of 7.42 percent senior unsecured MTNs. The notes mature on April 29, 2014.

On June 29, 2009, AltaGas issued \$100 million of 6.94 percent senior unsecured MTNs. The notes mature on June 29, 2016.

On March 25, 2010, AltaGas issued \$200 million of 5.49 percent senior unsecured MTNs. The notes mature on March 27, 2017.

On November 26, 2010, AltaGas issued \$175 million of 4.6 percent senior unsecured MTNs. The notes mature on January 15, 2018.

On March 24, 2011, AltaGas issued \$200 million of 4.1 percent senior unsecured MTNs. The notes mature on March 24, 2016.

Letter of Credit Facilities

On June 30, 2011, AltaGas held a \$75 million unsecured four-year extendible revolving term letter of credit facility with two Canadian chartered banks. On May 30, 2011, the credit facility's term was extended to four years with a new maturity date of May 30, 2015. AltaGas may borrow by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At June 30, 2011, AltaGas had letters of credit of \$59.3 million (December 31, 2010 - \$50.5 million) outstanding against the extendible revolving-term letter of credit facility.

On April 26, 2011, AltaGas closed a \$125 million unsecured bilateral credit facility. AltaGas may borrow by way of letters of credit under the credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At June 30, 2011, AltaGas had \$117.3 million letters of credit outstanding under the credit facility.

6. CAPITAL DISCLOSURE

AltaGas' objective for managing capital is to maintain its investment grade credit ratings and to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas considers shareholders' equity (including accumulated other comprehensive income), short-term and long-term debt (including current portion) less cash and cash equivalents to be part of its capital structure.

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. AltaGas' target debt-to-total capitalization ratio is 45 to 50 percent. AltaGas' debt-to-total capitalization ratio as at June 30, 2011, was 44.8 percent (December 31, 2010 - 42.7 percent).

	June 30 2011	December 31 2010
Debt		
Short-term debt	\$ 4,287	\$ 9,478
Current portion of long-term debt	105,886	1,508
Long-term debt	881,602	893,498
Less cash and cash equivalent	(10,550)	(2,109)
	981,225	902,375
Shareholders' equity	1,211,115	1,211,031
Total capitalization	\$ 2,192,340	\$ 2,113,406
Debt-to-total capitalization ratio (%)	44.8	42.7

All of the borrowing facilities have covenants customary for the types of facilities that must be met at the end of each calendar quarter. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations the Corporation purchases and sells natural gas, natural gas liquids (NGLs) 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

At June 30, 2011, all derivatives, other than those that meet the expected purchase, sale or usage requirements exemption, were carried on the Consolidated Balance Sheets at fair value. 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.

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

	Three Months Ended		Six Months Ended	
	2011	June 30 2010	2011	June 30 2010
Natural gas	\$ (5,669)	\$ 3,341	\$ (4,256)	\$ 6,146
Storage optimization	207	-	(1,249)	-
NGL Frac Spread	3,122	3,031	(3,591)	1,454
Power	(1,561)	(1,991)	(2,573)	1,673
Heat rate	(502)	-	195	(146)
Interest rate swaps	(74)	(426)	(178)	341
Foreign exchange	(79)	(126)	(330)	(356)
	\$ (4,556)	\$ 3,829	\$ (11,982)	\$ 9,112

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

	Unrealized		Six Months Ended June 30 2011	Unrealized gains (losses)	Tax (expense) recovery	Six Months Ended June 30 2010
	(losses)	Tax recovery				
NGL Frac Spread	\$ (898)	\$ 224	\$ (674)	\$ (3,025)	\$ 861	\$ (2,164)
Power	(4,509)	1,128	(3,381)	10,070	(2,843)	7,227
Bond forward	(1,993)	-	(1,993)	(2,597)	-	(2,597)
Available-for-sale	(4,337)	564	(3,773)	562	(81)	481
OCI	\$ (11,737)	\$ 1,916	\$ (9,821)	\$ 5,010	\$ (2,063)	\$ 2,947

Long-term Investments and other assets

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (formerly Magma Energy Corp., "Magma", "Alterra") through a private-equity offering. These shares were classified as available-for-sale. The changes in value for these common shares are reported within OCI, which was an unrealized loss of \$3.5 million for second quarter 2011 (second quarter 2010 - unrealized gain of \$0.6 million).

In July 2009, AltaGas purchased common shares of Alterra Power Corp. (formerly Magma) as part of its initial public offering. These shares were classified as held-for-trading. In July 2010, AltaGas purchased another tranche of common shares in Alterra, which were classified as held for trading. In second quarter 2011, AltaGas recognized an unrealized loss of \$3.8 million in the Corporate segment (second quarter 2010 - unrealized loss \$0.8 million). All shares of Alterra Power Corp. are reported in long-term investments and other assets.

8 OTHER LONG-TERM LIABILITIES

In 2010, AltaGas entered into a 60-year CPI Indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project. At June 30, 2011, AltaGas is obligated to pay approximately \$87.3 million over the next two years to BC Hydro in support of the construction and operation of the Northwest Transmission Line. This obligation is recorded in accounts payable and accrued liabilities for \$18 million and \$69.3 million in other long-term liabilities.

9. SHAREHOLDERS' CAPITAL

Authorization

At June 30, 2011, pursuant to the Arrangement, 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 then issued and outstanding common shares.

Preferred shares

On August 19, 2010, AltaGas issued 8,000,000 cumulative redeemable 5-year rate-reset preferred shares, series A (the Series A Preferred Shares) at a price of \$25 per Series A Preferred Share for aggregate proceeds of \$200 million.

Holders of the Series A Preferred Shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2015 (the Initial Period) at an annual rate of 5.00 percent, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payments of \$0.4589 per Series A Preferred Share were made on December 31, 2010. The dividend rate will reset on September 30, 2015, and every five years thereafter at a rate equal to the sum of the then 5-year Government of Canada bond yield plus 2.66 percent. The Series A Preferred Shares are redeemable by AltaGas, at its option, on September 30, 2015, and on September 30 of every fifth year thereafter.

Holders of Series A Preferred Shares will have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series B (the Series B Preferred Shares), subject to certain conditions, on September 30, 2015, and on September 30 of every fifth year thereafter. Holders of Series B Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.66 percent, as and when declared by the board of directors of AltaGas.

Common Shares Issued and Outstanding	Number of shares	Amount
December 31, 2010	82,526,399	\$ 1,023,033
Shares issued for cash on exercise of options	151,810	2,497
Shares issued under DRIP	721,733	16,813
Issued and outstanding at June 30, 2011	83,399,942	\$ 1,042,343

On July 1, 2010, AltaGas completed the conversion from an income trust to a corporation. Pursuant to the Arrangement, securityholders received one common share of AltaGas Ltd. for each trust unit and exchangeable unit. AltaGas Ltd. assumed the obligations of the Trust in respect of outstanding unit options. Upon exercise of the outstanding unit options, holders will receive the number of common shares equal to the number of Trust units they would have been entitled to receive in accordance with the Trust Unit Option Plan. Pursuant to the Arrangement, AltaGas Ltd. also assumed the Trust's Distribution Reinvestment and Optional Unit Purchase Plan (DRIP) and all associated agreements. All existing participants in the DRIP were deemed to be participants in the amended DRIP.

All references to shares and shareholders pertain to common shares and common shareholders subsequent to the conversion and units and unitholders prior to the conversion.

	Three Months Ended		Six Months Ended	
	2011	2010	2011	2010
Weighted Average Shares Outstanding				
Number of shares - basic	83,171,369	81,353,612	82,963,480	81,068,503
Dilutive equity instruments ⁽¹⁾	1,067,734	250,123	962,188	277,993
Number of shares - diluted	84,239,103	81,603,735	83,925,668	81,346,496

⁽¹⁾ Includes options and warrants

Share option plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. At June 30, 2011, 3,765,679 shares were reserved for issuance under the plan. As at June 30, 2011, options granted under the plan generally had a term of 8 years until expiry and vested no longer than over a 4-year period.

At June 30, 2011, outstanding options were exercisable at various dates within the next ten years. As at June 30, 2011, the unexpensed fair value of share option compensation cost associated with future periods was \$2.4 million (December 31, 2010 - \$3.9 million).

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

	Options outstanding	
	Number of options	Exercise price ⁽¹⁾
Share options outstanding, December 31, 2010	4,858,500	\$ 20.25
Granted	81,500	24.92
Exercised	(151,810)	16.01
Cancelled	(213,875)	21.30
Share options outstanding, June 30, 2011	4,574,315	\$ 20.42
Share options exercisable, June 30, 2011	1,613,565	\$ 23.12

⁽¹⁾ Weighted average.

The following table summarizes the employee share option plan as at June 30, 2011:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted Average Exercise price	Weighted Average Remaining contractual life	Number exercisable	Exercise price
\$5.00 to \$15.25	847,815	\$ 14.03	7.37	254,628	\$ 14.05
\$15.26 to \$25.08	3,055,000	20.58	8.42	707,563	22.08
\$25.09 to \$29.15	671,500	27.73	5.36	651,374	27.80
	4,574,315	\$ 20.42	7.78	1,613,565	\$ 23.12

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 on dividends declared and the trading price of the Corporation's shares. The shares vest on a graded vesting schedule. The compensation expense recorded in second quarter 2011 in respect of this plan was \$3.4 million (second quarter 2010 - \$3.9 million). As at June 30, 2011, the unexpensed fair value of equity-based compensation costs associated with future periods was \$14.7 million (December 31, 2010 - \$15.6 million).

10. NET INCOME APPLICABLE PER COMMON SHARE

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

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Numerator:				
Net income applicable to common shares - basic	\$ 16,569	\$ 28,365	\$ 43,120	\$ 64,761
Net income applicable to common shares - diluted	\$ 16,569	\$ 28,365	\$ 43,120	\$ 64,761
Denominator:				
Weighted-average number of shares	83,171	81,354	82,963	81,069
Dilutive equity instruments ⁽¹⁾	1,068	250	962	278
Number of shares outstanding - diluted	84,239	81,604	83,925	81,347
Basic net income applicable to common shares	\$ 0.20	\$ 0.35	\$ 0.52	\$ 0.80
Diluted net income per share	\$ 0.20	\$ 0.35	\$ 0.51	\$ 0.80

⁽¹⁾ Includes options and warrants.

11. COMMITMENTS

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain Wind Park. AltaGas has an obligation to pay a minimum of \$13.4 million over the next 11 years.

In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. AltaGas is obligated to pay approximately \$3.3 million per annum over the term of the contract for storage services.

12. NET CHANGE IN NON-CASH WORKING CAPITAL

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Accounts receivable	\$ (5,314)	\$ (441)	\$ 9,331	\$ 18,528
Inventory	8,384	(3,617)	11,583	(3,322)
Other current assets	(2,503)	(1,086)	(1,962)	(5,613)
Regulatory assets	1,122	(406)	(296)	2,116
Accounts payable and accrued liabilities	25,787	3,480	(29,824)	(13,992)
Dividends payable	48	-	95	-
Customer deposits	3,487	(140)	1,572	(1,917)
Regulatory liabilities	698	(830)	726	(506)
Other current liabilities	(514)	1,943	(5,579)	(3,270)
	31,195	(1,097)	(14,354)	(7,976)
Add back: (decrease) in capital costs payable	(27,074)	(8,384)	(9,549)	(16,484)
Net change in non-cash working capital	\$ 4,121	\$ (9,481)	\$ (23,903)	\$ (24,460)

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

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Interest paid	\$ 13,027	\$ 15,905	\$ 21,200	\$ 26,814
Income taxes paid	\$ 106	\$ 607	\$ 2,750	\$ 1,369

13. PENSION PLANS AND RETIREE BENEFITS

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

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

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2011	2010	2011	2010
Defined contribution plan	\$ 646	\$ 665	\$ 1,281	\$ 1,320
Defined benefit plan	105	509	316	960
Supplemental executive retirement plan	1,443	380	1,927	735
Other post-retirement benefit plans	106	107	161	161
	\$ 2,300	\$ 1,661	\$ 3,685	\$ 3,176

14. NON-MONETARY TRANSACTION

AltaGas has entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs were created through the generation of power at the Bear Mountain Wind Park between 2009 and 2010. The verified emission offsets received by AltaGas were used to offset the costs to comply with Specified Gas Emitters Regulation (SGER) in 2010. The contract was completed in second quarter 2010.

15. CONTINGENT LIABILITY

The Sundance B Unit 3 facility experienced an outage in second quarter 2010. The facility operator has notified AltaGas that it believes this event is a force majeure due to a high impact low probability event. AltaGas' management does not consider this to be a force majeure event. Mechanical failure has historically been treated as a maintenance item, rather than a force majeure event. Accordingly, AltaGas has not recorded a charge in its consolidated financial statements related to the notification from the facility operator.

16. COMPARATIVE FIGURES

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

17. SEASONALITY

The Utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales during the winter typically account for approximately two-thirds of annual revenue resulting in strong first and fourth quarter results and weaker second and third quarters.

18. SUBSEQUENT EVENT

On July 4, 2011, AltaGas was granted exemptive relief by the Alberta Securities Commission to prepare its financial statements in accordance with US GAAP without being registered with the SEC.

19. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities and the remainder is at the exchange amount. In accordance with the CICA Handbook Section 1700, in the year ended December 31, 2010, AltaGas changed the composition of its reportable segments as a result of modifications and growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Corporation's four reporting segments:

Gas	<ul style="list-style-type: none">– NGL processing and extraction plants– transmission pipelines to transport natural gas and NGL– natural gas gathering lines and field processing facilities– energy consulting and sale of natural gas and electricity– natural gas storage facilities
Power	<ul style="list-style-type: none">– coal-fired and gas-fired power output under power purchase arrangements and other agreements– gas-fired power plants– wind and run-of-river power plants– sale of power to commercial and industrial users in Alberta
Utilities	<ul style="list-style-type: none">– regulated natural gas distribution assets– production of natural gas to serve the power generation and heating needs of the town of Inuvik, Northwest Territories
Corporate	<ul style="list-style-type: none">– the cost of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management contracts

The following tables show the composition by segment:

**Three Months Ended
June 30, 2011**

	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 300,952	\$ 70,044	\$ 33,482	\$ (3,532)	\$ (28,305)	\$ 372,641
Unrealized losses on risk management	-	-	-	(4,555)	-	(4,555)
Cost of sales	(219,670)	(47,028)	(14,499)	-	26,790	(254,407)
Operating and administrative	(41,789)	(3,388)	(10,976)	(7,023)	1,515	(61,661)
Accretion of asset retirement obligations	(596)	(12)	-	-	-	(608)
Amortization	(13,675)	(4,077)	(3,038)	(884)	-	(21,674)
Foreign exchange gain	-	-	-	(49)	-	(49)
Interest expense	-	-	(2,938)	(10,776)	-	(13,714)
Income (loss) before income taxes	\$ 25,222	\$ 15,539	\$ 2,031	\$ (26,819)	-	\$ 15,973
Net additions (reductions) to:						
Capital assets ⁽¹⁾	\$ 44,765	\$ 21,398	\$ 11,590	\$ (1,263)	-	\$ 76,490
Energy services arrangements, contracts and relationships	\$ (1,007)	\$ 85,714	-	-	-	\$ 84,707
Long-term investment and other assets ⁽¹⁾	\$ (6,801)	\$ (523)	\$ 1,315	\$ 62	-	\$ (5,947)
Goodwill	\$ 143,726	-	\$ 55,771	-	-	\$ 199,497
Segmented assets	\$ 1,687,796	\$ 616,585	\$ 477,980	\$ 103,434	-	\$ 2,885,795

⁽¹⁾ Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.

**Six Months Ended
June 30, 2011**

	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 609,503	\$ 157,729	\$ 95,137	\$ (6,543)	\$ (72,325)	\$ 783,501
Unrealized losses on risk management	-	-	-	(11,983)	-	(11,983)
Cost of sales	(440,412)	(101,001)	(49,846)	-	71,155	(520,104)
Operating and administrative	(85,150)	(6,492)	(22,434)	(13,230)	1,170	(126,136)
Accretion of asset retirement obligations	(1,192)	(24)	-	-	-	(1,216)
Amortization	(27,350)	(8,100)	(6,122)	(1,768)	-	(43,340)
Foreign exchange loss	-	-	-	(12)	-	(12)
Interest expense	-	-	(5,763)	(20,855)	-	(26,618)
Income (loss) before income taxes	\$ 55,399	\$ 42,112	\$ 10,972	\$ (54,391)	-	\$ 54,092
Net additions (reductions) to:						
Capital assets ⁽¹⁾	\$ 41,959	\$ 50,628	\$ 16,307	\$ 1,080	-	\$ 109,974
Energy service arrangements, contracts and relationships	\$ (2,014)	\$ 88,190	-	-	-	\$ 86,176
Long-term investment and other assets ⁽¹⁾	\$ (12,389)	\$ (724)	\$ (273)	\$ (964)	-	\$ (14,350)
Goodwill	\$ 143,726	-	\$ 55,771	-	-	\$ 199,497
Segmented assets	\$ 1,687,796	\$ 616,585	\$ 477,980	\$ 103,434	-	\$ 2,885,795

Three Months Ended

June 30, 2010	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 244,355	\$ 79,650	\$ 26,462	\$ (400)	\$ (19,859)	\$ 330,208
Unrealized losses on risk management	-	-	-	3,829	-	3,829
Cost of sales	(166,647)	(51,949)	(10,498)	-	19,918	(209,176)
Operating and administrative	(41,917)	(3,095)	(9,374)	(7,691)	(59)	(62,136)
Accretion of asset retirement obligations	(712)	(8)	-	-	-	(720)
Amortization	(15,529)	(3,822)	(2,583)	(711)	-	(22,645)
Foreign exchange (loss)	-	-	-	39	-	39
Interest expense	-	-	(1,676)	(11,411)	-	(13,087)
Income (loss) before income taxes	\$ 19,550	\$ 20,776	\$ 2,331	\$ (16,345)	-	\$ 26,312
Net additions to:						
Capital assets ⁽¹⁾	\$ 21,590	\$ 9,793	\$ 8,612	\$ 1,258	-	\$ 41,253
Energy services arrangements, contracts and relationships	-	\$ 539	-	-	-	\$ 539
Long-term investment and other assets ⁽¹⁾	\$ (1,678)	\$ (22)	-	\$ (1,095)	-	\$ (2,795)
Goodwill	\$ 143,726	-	\$ 58,038	-	-	\$ 201,764
Segmented assets	\$ 1,653,075	\$ 439,644	\$ 416,123	\$ 139,516	-	\$ 2,648,358

⁽¹⁾ Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.

Six Months Ended

June 30, 2010	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 540,515	\$ 136,256	\$ 83,448	\$ (145)	\$ (74,653)	\$ 685,421
Unrealized gains on risk management	-	-	-	9,112	-	9,112
Cost of sales	(382,950)	(85,098)	(48,357)	-	73,939	(442,466)
Operating and administrative	(82,758)	(6,197)	(18,902)	(15,785)	714	(122,928)
Accretion of asset retirement obligations	(1,424)	(16)	-	-	-	(1,440)
Amortization	(31,144)	(7,646)	(5,390)	(1,431)	-	(45,611)
Foreign exchange gain	-	-	-	(209)	-	(209)
Interest expense	-	-	(3,359)	(21,229)	-	(24,588)
Income (loss) before income taxes	\$ 42,239	\$ 37,299	\$ 7,440	\$ (29,687)	\$ -	\$ 57,291
Net additions to:						
Capital assets ⁽¹⁾	\$ 61,035	\$ 13,484	\$ 11,886	\$ 3,009	-	\$ 89,414
Energy services arrangements, contracts and relationships	-	\$ 539	-	-	-	\$ 539
Long-term investment and other assets ⁽¹⁾	(2,102)	\$ (119)	-	\$ (5,584)	-	\$ (7,805)
Goodwill	\$ 143,726	-	\$ 58,038	-	-	\$ 201,764
Segmented assets	\$ 1,653,075	\$ 439,644	\$ 416,123	\$ 139,516	-	\$ 2,648,358

⁽¹⁾ Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.

Supplementary Quarterly Financial Information

(unaudited)

(\$ millions unless otherwise indicated)	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10
FINANCIAL HIGHLIGHTS⁽¹⁾					
Net Revenue ⁽²⁾					
Gas	81.3	87.8	79.4	75.6	77.7
Power	23.0	33.7	27.4	23.3	27.7
Utilities	19.0	26.3	22.0	14.8	16.0
Corporate	(8.1)	(10.4)	2.7	(10.0)	3.3
Intersegment Elimination	(1.5)	0.3	(0.8)	(1.1)	0.1
	113.7	137.7	130.7	102.6	124.8
EBITDA ⁽²⁾					
Gas	39.5	44.5	38.6	35.4	35.8
Power	19.6	30.7	24.3	20.8	24.6
Utilities	8.0	14.8	13.0	5.8	6.6
Corporate	(10.4)	(9.2)	(5.2)	(7.4)	(8.1)
	56.7	80.8	70.7	54.6	58.9
Operating Income (Loss) ⁽²⁾					
Gas	25.2	30.2	23.7	20.9	19.6
Power	15.5	26.6	20.4	17.0	20.8
Utilities	5.0	11.8	9.6	3.0	4.0
Corporate	(11.4)	(10.1)	(6.1)	(8.3)	(8.8)
	34.3	58.5	47.6	32.6	35.6

⁽¹⁾ Columns may not add due to rounding.

⁽²⁾ Non-GAAP financial measure.

Supplementary Quarterly Operating Information

(unaudited)

	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10
OPERATING HIGHLIGHTS					
GAS					
E&T					
Extraction inlet gas processed (Mmcf/d) ⁽¹⁾	828	909	870	776	758
Extraction volumes (Bbls/d) ⁽¹⁾	38,843	42,248	39,329	37,642	37,023
Frac spread - realized (\$/Bbl) ⁽¹⁾⁽³⁾	36.65	32.45	27.59	24.02	27.51
Frac spread - average spot price (\$/Bbl) ⁽¹⁾⁽³⁾	41.27	40.91	34.74	26.86	31.06
FG&P					
Processing Throughput (gross Mmcf/d) ⁽¹⁾	391	375	401	426	431
Capacity utilization (%) ⁽¹⁾	33	32	34	36	37
Energy Services					
Average volumes transacted (GJ/d) ⁽¹⁾	377,917	507,461	428,669	356,981	367,280
POWER					
Volume of power sold (GWh) ⁽¹⁾	727	740	752	711	706
Average price realized on sale of power (\$/MWh) ⁽¹⁾⁽⁶⁾	64.26	78.76	64.43	61.53	79.98
Alberta Power Pool average spot price (\$/MWh) ⁽¹⁾	52.12	83.33	45.90	35.69	80.56
UTILITIES					
Natural gas deliveries - end-use (PJ) ⁽⁴⁾	3.7	9.3	7.0	2.3	3.3
Natural gas deliveries - transportation (PJ) ⁽⁴⁾	1.2	1.3	1.3	1.3	1.4
Service sites ⁽²⁾	74,823	75,055	74,664	73,531	72,827
Degree day variance (%) - AUI ⁽⁵⁾	0.5	23.6	4.4	23.0	4.0
Degree day variance (%) - Heritage Gas ⁽⁵⁾	19.7	8.0	(11.0)	(48.1)	(15.4)

(1) Average for the period.

(2) As at period end.

(3) Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

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

(5) Degree days relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius for AUI and 18 degrees Celsius for Heritage. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations.

(6) Includes both Alberta and British Columbia sale of power.

Other Information

DEFINITIONS

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

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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