



## NEWS RELEASE

# ALTAGAS ANNOUNCES DIVIDEND INCREASE AND REPORTS THIRD QUARTER RESULTS

**Calgary, Alberta (October 27, 2011)** – AltaGas Ltd.'s ("AltaGas" or the "Corporation") (TSX: ALA) Board of Directors approved a five percent increase in the annual common share dividend rate to \$1.38 from \$1.32 per common share. The first monthly dividend payment of \$0.115 per common share is payable on or after December 15, 2011 to common shareholders of record at close of business on November 25, 2011.

"The dividend increase reflects the Board's confidence in our underlying business and the progress we have made on our major growth projects," said David Cornhill, Chairman and CEO of AltaGas. "We are committed to delivering superior economic returns to our shareholders by balancing income and growth. The increase underscores our ability to deliver growing and stable dividends."

AltaGas also reported net income applicable to common shares for third quarter 2011 of \$10.6 million (\$0.13 per share) compared to \$6.0 million (\$0.07 per share) for same period 2010. Normalizing for mark-to-market accounting and the impact of major turnarounds in the Gas business, net income applicable to common shares for the quarter was \$19.0 million (\$0.23 per share) compared to \$16.2 million (\$0.20 per share) in same quarter 2010.

On a cash flow basis, funds from operations for third quarter 2011 were \$45.9 million (\$0.55 per share), an 11 percent increase compared to \$41.5 million (\$0.51 per share) in third quarter 2010. EBITDA in third quarter 2011 was \$56.5 million (\$0.68 per share) compared to \$54.5 million (\$0.67 per share) in same period last year.

As previously disclosed, third quarter was impacted by the planned turnarounds at Harmattan and Younger. The quarter was also impacted by a maintenance outage at Sundance B in August. The financial impact from the Gas turnarounds was approximately \$6.0 million (pre-tax) and in Power \$3.0 million (pre-tax). In addition, during the quarter an unfavourable 30-day rolling average power price also resulted in lower operating income than would be expected given the significantly higher average spot power prices this quarter compared to the same quarter last year. In third quarter 2011, AltaGas also reported pre-tax unrealized mark-to-market losses of \$5.1 million compared to \$13.3 million in third quarter 2010.

"We had a very good quarter with the business delivering financial results that were higher than last year, even with three of our largest assets being impacted by planned maintenance outages in the quarter," said David Cornhill "Our businesses continue to deliver strong results and we are on track to exceed last year's operating results."

AltaGas continues to make great progress on the \$1.6 billion of capital projects under construction and construction ready. The first phase of the new Gordondale plant, the Henderson Pipeline, was completed on time and on budget and is expected to begin transporting gas in early November to the Pouce Coupe facility. Construction on the 120 Mmcf/d, Gordondale plant commenced this quarter with access road upgrade work complete and plant site clearing substantially complete. Applications are underway to add a 3.4 MW gas-fired peaking plant onsite. Major tie-ins for the Co-stream project and the 15 MW Cogeneration II project were completed during the turnaround at the Harmattan Complex that came back online on October 14, 2011. The Gordondale, Co-stream and Cogen II projects are on schedule for their expected in-service dates in 2012.

The Northwest Projects continue to gain momentum as AltaGas and the Tahltan Central Council signed Impact Benefit Agreements (IBA) on September 28, 2011 for McLymont Creek and Volcano Creek projects that will produce approximately 70 MW to 88 MW of hydroelectricity. Final discussions are underway with BC Hydro regarding Electricity Purchase Agreements (EPA) for the two projects. Tunneling is ahead of schedule at the, 195 MW, Forrest Kerr site, with

the construction access tunnel complete and the main access tunnel 50 percent complete. Excavation of the power tunnel access portal and the headworks facility began in the quarter. All of the Corporation's major projects are on time and on budget.

**FINANCIAL HIGHLIGHTS<sup>(1)</sup>:**

- Earnings before interest, taxes, depreciation and amortization (EBITDA) were \$56.5 million (\$0.68 per share) for third quarter 2011, compared to \$54.5 million (\$0.67 per share) for same quarter 2010.
- Funds from operations were \$45.9 million (\$0.55 per share) for third quarter 2011, up from \$41.5 million (\$0.51 per share) for same period 2010.
- Net debt as at September 30, 2011 was \$1,049.3 million, compared to \$981.2 million at June 30, 2011 and \$902.4 million at December 31, 2010. AltaGas' debt to total capitalization ratio as at September 30, 2011 was 46.6 percent, versus 44.8 percent at June 30, 2011 and 42.7 percent as at December 31, 2010.
- In third quarter, AltaGas amended and extended the Utility Group's \$200 million unsecured, extendible revolving credit facility to four years with a new maturity date of November 17, 2015.
- On October 17, 2011, AltaGas issued \$200 million of senior unsecured medium term notes. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019.

*<sup>(1)</sup> Includes non-GAAP financial measures. See discussion in "Non-GAAP Financial Measures" section of this quarter's MD&A.*

**CONFERENCE CALL AND WEBCAST DETAILS:**

AltaGas will hold a conference call today at 9:00 a.m. MT (11:00 a.m. ET) to discuss third quarter 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\\_events](http://www.altagas.ca/investors/presentations_and_events)

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 3623410. The replay expires at midnight (ET) on November 3, 2011. The webcast will be archived for one year.

The complete third quarter report for 2011, including Management's Discussion and Analysis and unaudited financial statements, is available on [www.altagas.ca](http://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 nine months ended September 30, 2011, compared to the three and nine months ended September 30, 2010. This MD&A dated October 27, 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 nine months ended September 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](http://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](http://www.sedar.com).*



## CONSOLIDATED FINANCIAL REVIEW

The third 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.

### Results of Operations by Reporting Segment

Operating income <sup>(1)</sup> (unaudited) (\$ millions)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Gas	18.4	20.9	73.8	63.2
Power	21.5	17.0	63.6	54.3
Utilities	2.9	3.0	19.6	13.8
Sub-total: Operating segments	42.8	40.9	157.0	131.3
Corporate	(9.4)	(8.3)	(30.9)	(25.7)
	33.4	32.6	126.1	105.6

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

### Three Months Ended September 30

Results in third quarter were strong as processing volumes continued to grow, more power was generated and rate base grew at the utilities. AltaGas also continued to benefit from higher frac spreads on unhedged volumes.

The third quarter was impacted by the planned turnarounds at the Younger Extraction Plant (Younger) and Harmattan facility, with approximately \$6.0 million lower operating income. The turnaround at Younger included debottlenecking of the facility to allow processing volumes to increase to 650 Mmcf/d from 580 Mmcf/d. During the turnaround at the Harmattan facility, AltaGas completed tie-in work required for the Co-stream and Cogeneration #2 projects coming on line in 2012 as well as work required to move the turnaround cycle from three years to four years.

In the Power business, results in the third quarter were impacted by a maintenance outage at the Sundance B facility in August. The financial impact of the outage was approximately \$3.0 million lower operating income. In addition, during the quarter, an unfavourable 30-day rolling average power price (RAPP) also resulted in lower operating income than would be expected given the significantly higher spot power prices in the quarter compared to the same quarter last year.

In third quarter 2011, AltaGas reported pre-tax unrealized mark-to-market losses of \$5.1 million compared to \$13.3 million in third quarter 2010.

Net income applicable to common shares for third quarter 2011 was \$10.6 million (\$0.13 per share) compared to \$6.0 million (\$0.07 per share) for same period 2010. Normalizing for the impact of all mark-to-market accounting and the Gas turnarounds, net income applicable to common shares in third quarter 2011 was \$19.0 million (\$0.23 per share) compared to \$16.2 million (\$0.20 per share) in same quarter 2010.

The Gas segment reported lower operating income in third quarter 2011 compared to same quarter 2010 as a result of scheduled turnarounds discussed above and lower volumes at some facilities, partially offset by higher frac spreads and increased volume of natural gas liquids processed. Field gas processing throughput during third quarter averaged 404 Mmcf/d compared to the first and second quarter of 375 Mmcf/d and 391 Mmcf/d, respectively.

The Power segment reported higher operating income in third quarter 2011 compared to same quarter 2010 due to higher spot Alberta power prices, the addition of the cogeneration facility at the Harmattan complex, higher generation from gas-fired peaking plants and stronger results from Bear Mountain Wind Park (Bear Mountain), partially offset by higher costs due to an unfavorable 30-day rolling average power price (RAPP), higher environmental compliance costs and higher transmission costs.

The Utility segment reported lower operating income in third quarter 2011 compared to same quarter 2010 mainly due to timing differences between revenue generation and the incurrence of recoverable costs at AltaGas Utilities Inc. (AUI). These timing differences were partially offset by rate base growth at AUI and Heritage Gas Limited (Heritage Gas) and are usual for this business as a result of seasonality.

The Corporate segment reported a loss in third quarter 2011 compared to income in the same quarter last year. The loss was mainly due to a mark-to-market adjustment to an equity investment in a publicly traded company.

On a cash flow basis, funds from operations in third quarter 2011 were \$45.9 million (\$0.55 per share), an 11 percent increase compared to \$41.5 million (\$0.51 per share) in third quarter 2010. EBITDA in third quarter 2011 was \$56.5 million (\$0.68 per share) compared to \$54.5 million (\$0.67 per share) in same period last year. In third quarter 2011, AltaGas declared dividends to common shareholders of approximately 60 percent of funds from operations.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to \$0.115 per common share from \$0.11 per common share. The first monthly dividend of \$0.115 per common share is payable on or after December 15, 2011 to common shareholders of record at close of business on November 25, 2011.

On a consolidated basis, net revenue for third quarter 2011 was \$117.9 million compared to \$102.6 million in same period 2010. The Gas segment reported higher net revenue compared to the prior year due to higher realized frac exposed volumes and higher frac margins, partially offset by lower gas processing volumes at some facilities and fee-for-service revenues, turnarounds at Harmattan and Younger, and lower transmission revenues. Net revenue in the Power segment increased due to higher spot Alberta power prices, the addition of the Harmattan gas-fired cogeneration facility in fourth quarter 2010, higher generation from gas fired peaking plants, and higher results from Bear Mountain. Increases were partially offset by higher hedging losses, higher PPAs' costs due to an unfavourable 30-day RAPP, higher environmental compliance costs and higher transmission costs. The Utility segment reported higher net revenue due to higher recoverable costs and rate base growth at AUI and Heritage Gas. The Corporate segment recorded higher net revenue due to lower unrealized losses on risk management contracts and a lower unrealized mark-to-market loss on an equity investment.

Operating and administrative expense for third quarter 2011 was \$65.0 million, up from \$58.5 million in third quarter 2010. The increase was primarily due to an increase in operating costs at extraction facilities due to turnarounds and higher volumes processed partially offset by lower general and administrative costs.

Amortization expense for third quarter 2011 was \$22.4 million compared to \$21.1 million in same period 2010. The increase was due the addition of new and expanded facilities. Accretion expense for third quarter 2011 was \$0.6 million compared to \$0.7 million for same period 2010.

Interest expense in third quarter 2011 was \$12.8 million compared to \$12.1 million for same period 2010. The increase was due to a higher average borrowing rate of 6.1 percent (2010 - 5.7 percent) and higher average debt balance of \$1,032.3 million (2010 - \$985.1 million).

Capitalized interest in third quarter 2011 was \$3.1 million compared to \$1.9 million in same period 2010.

In third quarter 2011, an income tax expense of \$3.7 million was reported compared to an expense of \$3.0 million in third quarter 2010.

### **Nine Months Ended September 30**

For the nine months ended September 30, 2011, AltaGas delivered stronger results from its operating businesses compared to the same period last year. Operating income from the three business segments are all higher on a year-to-date basis, at \$157.0 million a 20 percent increase over the same period in 2010. The results reflect the higher volume processed in gas and generated in power as well as higher rate base at the utilities. Also contributing to the stronger results is the impact of higher power prices in Alberta and higher frac spreads. Results in the nine months ended September 30, 2011, were also impacted by the turnarounds in Gas and Power as well as the higher 30-day RAPP described in the results for the three months ended September 30.

Net income applicable to common shares for the first nine months of 2011 was \$53.7 million (\$0.65 per share) compared to \$70.8 million (\$0.87 per share) for the same period of 2010. Normalizing for the impact of all mark-to-market accounting and Gas turnarounds, net income applicable to common shares for the first nine months ended September 30, 2011 was \$76.8 million (\$0.92 per share) compared to \$76.0 million (\$0.94 per share) for the same period of 2010. AltaGas reported income tax expense of \$9.2 million for the first nine months of 2011 compared to an income tax recovery of \$4.5 million for the same period of 2010.

For the nine months ended September 30, 2011, AltaGas reported a pre-tax unrealized loss on risk management contracts of \$15.5 million compared to a pre-tax loss of \$1.3 million for the same period 2010. In the first nine months of 2011 the Corporation also reported a pre-tax unrealized loss related to an equity investment of \$8.1 million compared to a pre-tax unrealized loss of \$5.0 million in the same period of 2010. On a year-to-date basis, the impact of the turnarounds at Younger and Harmattan was the same as for third quarter.

The Gas segment reported higher operating income for the first nine months of 2011 compared to the same period of 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, 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, the impact of scheduled turnarounds, 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 for the first nine months of 2011 compared to the same period of 2010 as a result of higher spot Alberta power prices, higher earnings from Bear Mountain, the addition of the gas fired cogeneration facility at the Harmattan complex, and higher generation from gas-fired peaking plants. These increases were partially offset by higher hedging losses, higher costs due to an unfavourable 30-day RAPP, higher environmental compliance costs and higher transmission costs.

The Utility segment reported higher operating income for the first nine months of 2011 compared to the same period of 2010 mainly due to colder weather in Alberta and Nova Scotia in first quarter 2011 and growth in rate base and higher recoverable costs at AUI and Heritage Gas.

The Corporate segment reported a higher loss for the first nine months of 2011 compared to the same period of last year. The increase was due to the unrealized mark-to-market loss related to an equity investment in a publicly traded company.

On a cash flow basis, funds from operations for the first nine months of 2011 were \$156.6 million (\$1.88 per share), a 14 percent increase compared to \$137.1 million (\$1.69 per share) for the same period of 2010. EBITDA for the first nine months of 2011 was \$193.7 million (\$2.33 per share), an 11 percent increase compared to \$174.5 million (\$2.15 per share) for the same period last year. For the nine months ended September 30, 2011, AltaGas declared dividends to common shareholders of approximately 53 percent of funds from operations.

On a consolidated basis, net revenue for the nine months ended September 30, 2011, was \$369.3 million compared to \$354.7 million for the 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 spot Alberta power prices, increased generation from Bear Mountain, the addition of the Harmattan cogeneration facility and higher generation from the gas-fired peaking plants, partially offset by higher hedging losses, higher costs related to the PPAs including an unfavorable 30-day RAPP in third quarter, higher environmental compliance costs and higher transmission costs. 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 growth in rate base and higher recoverable costs at AUJ and Heritage Gas. The Corporate segment recorded lower net revenue due to higher unrealized losses on risk management contracts and on an equity investment.

Operating and administrative expense for the first nine months of 2011 was \$191.1 million, up from \$181.5 million for the same period of 2010. The increase was primarily due to incremental costs at extraction facilities due to higher volumes processed and expenses incurred during turnarounds, partially offset by lower general and administrative expenses.

Amortization expense for first nine months of 2011 was \$65.7 million compared to \$66.8 million for same period of 2010. Accretion expense for the first nine months of 2011 was \$1.8 million compared to \$2.2 million for the same period of 2010. The decreases were primarily due to a change in estimates for the expected remaining useful lives of some assets within the Gas segment, partially offset by the addition of new and expanded facilities.

Interest expense for the first nine months of 2011 was \$39.3 million compared to \$36.7 million for the same period of 2010. The increase was due to a higher average borrowing rate of 6.3 percent (2010 - 5.2 percent) partially offset by lower average debt balances of \$982.9 million (2010 - \$1,018.3 million).

Capitalized interest in the first nine months of 2011 was \$6.6 million compared to \$2.6 million in the same period of 2010.

For the first nine months of 2011, an income tax expense of \$9.2 million was reported compared to a recovery of \$4.5 million for the same period of 2010. The increase was due to higher income subject to taxation as a result of the conversion to a corporate structure in July 2010. 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 income from its three business segments in 2011 compared to 2010. In the Gas business volumes processed are expected to increase at certain gas processing and extraction facilities as producers look to increase net-backs from liquids-rich gas and higher realized frac spreads. The increases will be partially offset by the impact of turnarounds at Younger (third quarter 2011) and the Harmattan Complex (third and fourth quarters 2011), lower daily take-or-pay volumes on Suffield and lower results from some gas processing regions that continue to have limited producer activity as a result of lower natural gas prices and where gas composition is not considered to be rich. The gas business is also expected to benefit from higher frac spreads 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 spreads to average approximately \$41/Bbl after deducting extraction premiums compared to \$27/Bbl in 2010. For the remainder of 2011, the Corporation estimates that 14 percent of total extraction volumes will be exposed to frac spread. For fourth quarter 2011, approximately 80 percent of the exposure has been hedged at an average price of \$30.50/Bbl. For 2012, AltaGas has hedged approximately two-thirds of its volumes that are exposed to frac spread at an average price of approximately \$34.50/Bbl.

AltaGas expects earnings in the Power segment to be higher in 2011 than 2010 as a result of higher power 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 65 percent of power exposed to Alberta power prices at an average price of \$72/MWh for fourth quarter 2011. For 2012, AltaGas is approximately 50 percent hedged at an average price of \$64/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 continue to execute short-term hedges at premium prices to long-term prices.

Rate base growth in its Alberta and Nova Scotia natural gas distribution utilities of 13 percent and 24 percent, respectively in 2011, is expected to drive operating income for the Utility segment.

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 approximately 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. 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 utility customers.

## **GROWTH CAPITAL**

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2011 to be approximately \$545 million allocated approximately 50 percent for Gas, 40 percent for Power and 10 percent for Utilities. As at September 30, 2011, approximately \$535 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, its available credit on bank lines and its continued strong access to capital markets. At September 30, 2011, the Corporation had \$823.4 million of available credit facilities.

AltaGas continues to make progress on the projects currently under construction and advanced development. AltaGas mitigates project cost escalation and schedule risk through its procurement and contracting strategies.

### **Forrest Kerr Hydroelectric Project**

Construction of the 195 MW Forrest Kerr run-of-river power generation project is progressing well. The project includes approximately 4,800 of linear meters of tunnelling. The excavation of the access tunnels has advanced as expected due to a stable and consistent rock formation. To date, a total of 1,135 linear meters have been excavated. By the end of 2011, approximately 88 percent of the project costs will be contractually committed to fixed price contracts. The Forrest Kerr project is expected to be completed and operational by July 2014 for a total cost of approximately \$725 million.

### **McLymont Creek and Volcano Creek Hydroelectric Projects**

On September 28, 2011, AltaGas signed the Impact Benefit Agreements (IBAs) for the proposed 55 to 70 MW McLymont Creek and 15 to 18 MW Volcano Creek run-of-river projects located in the Tahltan Nation traditional territory. AltaGas is currently in the final stages of discussions with BC Hydro regarding an Electricity Purchase Agreement (EPA) for the projects. Subject to permitting, the construction of the projects will be initiated in the latter half of 2012 and 2013 for McLymont Creek and Volcano Creek, respectively. 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 use 250 Mmcf/d of existing spare capacity to recover ethane and other NGLs from natural gas sourced from the NGTL Western System. The project is expected to cost approximately \$147 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.

AltaGas had \$122 million of committed costs by the end of September 2011. Pipeline construction has commenced and major equipment tie-ins were completed during the scheduled plant turnaround at Harmattan. 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 be incurred.

In early January 2011, two of initial intervenors in AltaGas' Energy Resources Conservation Board (ERCB) application filed notices of motion for leave to appeal the ERCB decision to approve the Harmattan Co-stream project 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 appealing parties were granted leave to appeal on August 8, 2011. The appealing parties filed their notices of appeal with the Alberta Court of Appeal on September 7, 2011. AltaGas continues to believe that the grounds set forth by the intervening parties for appeal are without merit. AltaGas remains committed to the schedule as outlined above. One of the parties applied to the ERCB for a stay of the ERCB decision approving the Harmattan Co-stream project, which was rejected by the ERCB on September 9, 2011.

### **Gordondale Gas Plant**

During the quarter, AltaGas began construction of 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 \$236 million and be in service late 2012. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility.

Construction of the Henderson Pipeline (Phase one of the Gordondale facility) was completed in the third quarter, on time and on budget. The pipeline connects to the Pouce Coupe facility and provides processing services to Encana for early production of 15 Mmcf/d. Incremental gas processing at the Pouce Coupe facility is delayed until fourth quarter 2011 pending the completion of Encana's scope of work.

AltaGas had \$117 million of committed costs 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 began construction of a second 15 MW cogeneration unit at the Harmattan complex to supply steam and power to the Co-stream project. The Harmattan Cogeneration #2 project is estimated to cost \$24 million and be in service during second quarter 2012.

To date, \$17 million have been committed for major equipment and services. The application to the Alberta Utilities Commission (AUC) was submitted in June 2011 and was deemed complete. At the AUC's direction, AltaGas commenced public advertising of the project during the quarter. Construction commenced in third quarter 2011 which focused on tie-ins that were completed during the scheduled plant turnaround at Harmattan.

### 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 September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Net revenue	117.9	102.6	369.3	354.7
Add: Cost of sales	251.7	194.8	771.8	637.2
Revenue (GAAP financial measure)	369.6	297.4	1,141.1	991.9

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 September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Operating income	33.4	32.6	126.1	105.6
Add (deduct): Unrealized (losses) on risk management contracts	(3.5)	(10.4)	(15.5)	(1.3)
Interest expense	(12.8)	(12.1)	(39.3)	(36.7)
Foreign exchange (loss) gain	(0.1)	0.2	(0.1)	-
Income tax (expense) recovery	(3.7)	(3.0)	(9.2)	4.5
Preferred share dividend (net of tax)	(2.8)	(1.3)	(8.3)	(1.3)
Net income applicable to common shares (GAAP financial measure)	10.6	6.0	53.7	70.8

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 operating performance 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).

<b>EBITDA</b> (unaudited) (\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	<b>2011</b>	2010	<b>2011</b>	2010
EBITDA	<b>56.5</b>	54.5	<b>193.7</b>	174.5
Add (deduct):				
Unrealized (losses) on risk management contracts	<b>(3.5)</b>	(10.4)	<b>(15.5)</b>	(1.3)
Amortization	<b>(22.4)</b>	(21.2)	<b>(65.8)</b>	(66.7)
Accretion of asset retirement obligations	<b>(0.6)</b>	(0.7)	<b>(1.8)</b>	(2.2)
Interest expense	<b>(12.8)</b>	(12.1)	<b>(39.3)</b>	(36.7)
Foreign exchange (loss) gain	<b>(0.1)</b>	0.2	<b>(0.1)</b>	-
Income tax (expense) recovery	<b>(3.7)</b>	(3.0)	<b>(9.2)</b>	4.5
Preferred share dividends (net of tax)	<b>(2.8)</b>	(1.3)	<b>(8.3)</b>	(1.3)
Net income applicable to common shares (GAAP financial measure)	<b>10.6</b>	6.0	<b>53.7</b>	70.8

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).

<b>Adjusted net income</b> (unaudited) (\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	<b>2011</b>	2010	<b>2011</b>	2010
Adjusted net income	<b>14.6</b>	16.2	<b>72.3</b>	76.0
Add (deduct):				
After-tax unrealized gain (loss) on risk management contracts	<b>(2.6)</b>	(7.7)	<b>(11.6)</b>	(0.9)
After-tax unrealized gain (loss) on held-for-trading (HFT) financial assets	<b>(1.4)</b>	(2.5)	<b>(7.0)</b>	(4.3)
Net income applicable to common shares (GAAP financial measure)	<b>10.6</b>	6.0	<b>53.7</b>	70.8

Adjusted net income is a better reflection of actual business performance than net income since changes in value of risk management contracts and financial assets held-for-trading are subject to the 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. 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.

Funds from operations (unaudited) (\$ millions)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Funds from operations	45.9	41.5	156.6	137.1
Add (deduct): Net change in non-cash working capital	19.0	29.1	(4.9)	5.4
Asset retirement obligations settled	-	(0.2)	(0.2)	(0.3)
Cash from operations (GAAP financial measure)	64.9	70.4	151.5	142.2

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		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
<b>E&amp;T</b>				
Extraction inlet gas processed (Mmcf/d) <sup>(1)</sup>	871	776	869	773
Extraction ethane volumes (Bbls/d) <sup>(1)</sup>	25,456	24,589	26,202	25,339
Extraction NGL volumes (Bbls/d) <sup>(1)</sup>	14,325	13,053	14,076	12,356
Total extraction volumes (Bbls/d) <sup>(1)</sup>	39,781	37,642	40,277	37,695
Frac spread - realized (\$/Bbl) <sup>(1) (2)</sup>	22.95	24.02	30.37	27.14
Frac spread - average spot price (\$/Bbl) <sup>(1) (3)</sup>	42.15	26.86	41.47	30.87
<b>FG&amp;P</b>				
Processing throughput (gross Mmcf/d) <sup>(1)</sup>	404	425	391	430
Capacity utilization (%) <sup>(4)</sup>	34	36	33	36
<b>Energy Services</b>				
Average volumes transacted (GJ/d) <sup>(5)</sup>	340,396	356,981	373,814	376,436

<sup>(1)</sup> Average for the period.

<sup>(2)</sup> Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from sales recorded by the business during the period on frac exposed volumes plus the settlement value of frac hedges settled in the period divided by the total frac exposed volumes produced during the period. Third quarter 2011 realized frac spread was affected by the Younger Extraction Plant turnaround and the timing of NGL sales and NGL volumes reported.

<sup>(3)</sup> 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.

<sup>(4)</sup> As at the end of the reporting period.

<sup>(5)</sup> Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

During third quarter 2011, average ethane and NGL volumes in the extraction business increased by 867 Bbls/d and 1,272 Bbls/d respectively, compared to third quarter 2010. Average ethane and NGL volumes increased by 863 Bbls/d and 1,720 Bbls/d, respectively, during the first nine months of 2011 compared to the same period of 2010. Volumes were higher at most extraction facilities as a result of higher inlet volumes and successful contracting efforts for Empress extraction facilities partially offset by the Younger turnaround, which commenced June 13 and returned to full operations on July 11, 2011, and the Harmattan turnaround, which began in late September.

In FG&P, throughput in third quarter 2011 averaged 404 Mmcf/d compared to 425 Mmcf/d in same quarter 2010. Volumes were lower, despite the addition of the Marlboro gas processing plant in May and expansion of the Alder Flats facility completed at the end of April. The lack of producer activity in response to low natural gas prices has resulted in overall lower average processing volumes of approximately 74 Mmcf/d from natural declines or well shut-ins during the

first nine months of 2011 compared to the same period in 2010. During this same period, certain FG&P facilities saw increased throughput on average of 35 Mmcfd over the prior year period.

Over each of the past three quarters, volumes processed at the field processing plants have increased. In third quarter these facilities processed an average of 29 Mmcfd of natural gas more than first quarter 2011 and 13 Mmcfd more than second quarter 2011.

### **Three Months Ended September 30**

The Gas segment recorded operating income of \$18.4 million in third quarter 2011, compared to \$20.9 million in third quarter 2010. The decrease was primarily due to planned major turnarounds at the Younger and Harmattan plants.

The scheduled turnaround at Harmattan began on September 22. Operating income for the third quarter was impacted by approximately \$2.0 million which includes estimated lost revenue and increased operating costs. The turnaround was completed and returned to normal operations in mid-October. During the turnaround at Harmattan, work was completed to enable the plant to move to a four-year turnaround cycle from a three-year turnaround cycle. Work required to tie-in the Harmattan Co-stream and Cogeneration #2 projects to the Harmattan facility in 2012 was also completed during the turnaround.

In late June 2011, 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 of approximately \$4.0 million was recorded in third quarter 2011, which includes estimated lost revenue and increased operating costs.

Excluding the impact of the turnarounds, third quarter operating income would have been \$24.3 million or 16 percent higher than the comparable quarter. Operating income increased as a result of higher frac margins and volumes, incremental contributions from new and expanded gas processing facilities, higher extraction fee-for-service revenues and increased margins realized by gas services. These were partially offset by higher non-recoverable operating expenses due to increased extraction volumes, lower realized frac spread, lower volumes processed at certain gas processing facilities and lower daily contract quantity on the Suffield system.

Net revenue in the Gas segment for third quarter 2011 was \$77.7 million compared to \$75.6 million for same period 2010. Net revenue increased largely due to higher realized frac exposed margins and volumes of \$3.2 million, contributions from new and expanded gas processing facilities of \$2.1 million, higher recoveries of operating costs of \$1.5 million, higher fee-for-service revenues earned by extraction facilities of \$1.1 million and increased contributions of \$1.1 million from gas services. These increases were partially offset by the impact of the Younger and Harmattan turnarounds of \$3.9 million, lower volumes processed at certain gas processing facilities of \$2.1 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 third quarter 2011 was \$44.8 million compared to \$40.2 million in third quarter 2010. Operating costs during the quarter increased as a result of the Younger and Harmattan turnarounds, the addition or expansion of gas processing assets and variable costs associated with more extraction volumes.

Amortization expense in third quarter 2011 was \$13.8 million compared to \$13.7 million in third quarter 2010. Accretion expense in third quarter 2011 was \$0.6 million compared to \$0.7 million in third quarter 2010.

### **Nine Months Ended September 30**

The Gas segment reported operating income of \$73.8 million for the first nine months of 2011, a 17 percent increase compared to \$63.2 million for the same period of 2010.

Excluding the financial impact of the Younger and Harmattan turnarounds of approximately \$6.0 million, operating income for the first nine months of 2011 would have been \$79.8 million or 26 percent higher than the comparable

quarter. Operating income increased due to higher frac exposed margins and volumes, the sale of the Groundbirch facility, higher fees earned from increased extraction volumes, settlement of a take-or-pay contract, contributions from new and expanded gas processing facilities, lower amortization, increased contributions from gas services 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 the first nine months of 2011 was \$246.7 million compared to \$233.2 million for the same period of 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 \$11.8 million due to higher frac exposed margins and volumes, \$2.9 million from higher operating expense recoveries, \$2.1 million from higher fees earned from increased extraction volumes, increased contributions of \$1.2 million from gas services and lower provision for doubtful accounts of \$1.0 million. These increases were partially offset by the lost revenue impact from the Younger and Harmattan turnarounds, lower transmission revenues of \$3.8 million which was driven largely by lower daily contract quantity on the Suffield system, lower volumes processed at certain gas processing facilities of \$3.7 million and lower natural gas storage margins of \$2.2 million.

Operating and administrative expense for the first nine months of 2011 was \$130.0 million compared to \$123.0 million for the same period of 2010. Operating costs during the period increased as a result of the Younger and Harmattan turnarounds, the addition or expansion of gas processing assets and variable costs associated with more extraction volumes. These increases were partially offset by lower administration costs as a result of increased efficiencies and cost saving measures implemented.

Amortization expense for the nine months ended September 30, 2011, was \$41.2 million compared to \$44.9 million for the same period 2010. Accretion expense for the first nine months of 2011 was \$1.8 million compared to \$2.1 million for the same period of 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 operating income in 2011 compared to 2010. Stronger results are expected from the extraction and some 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, scheduled turnarounds, lower daily quantity commitment on the Suffield natural gas transmission system and lower margins in the storage business.

Throughput at the 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 expected to be 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 volumes in 2011 to exit the year higher than the 2010 annual average within the field gathering and processing business as a result of prior year's projects to expand and modify certain existing facilities, the addition of the Marlboro plant and the completed 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.

Plant and pipeline modifications are underway to optimize the Bantry and Princess facilities to process additional solution gas in the fourth quarter. Throughput is expected to reach 28 Mmcf/d by the end of the year. This represents an increase of 54 percent or approximately 10 Mmcf/d compared to the average for the nine months ended September 30, 2011.

The Blair Creek facility is currently undergoing a debottlenecking project to increase its capacity to 32 Mmcf/d. Regulatory approval for this expansion was recently received and the project is expected to be completed in late fourth quarter 2011. Management has recently initiated a \$43 million project to expand production capacity at Blair Creek to 70 Mmcf/d which is expected to be completed by second quarter 2012. The expansion is contractually supported by three active producers in the area.

The recently acquired Marlboro Plant is proceeding forward with its next phase of expansion of 13 Mmcf/d to gross capacity of 53 Mmcf/d (AltaGas net 21 Mmcf/d) and is expected to be operational early first quarter 2012.

Offsetting these gains will be the costs of turnarounds at the Younger and Harmattan facilities. The impact of the Younger turnaround on operating income was approximately \$4.0 million. Harmattan's turnaround commenced in late September and continued until mid-October and is expected to reduce operating income by approximately \$7.0 million in 2011 compared to 2010, of which approximately \$5.0 million is expected to be recognized in fourth quarter 2011. Lower daily contract quantity on the Suffield system is expected to lower operating income by \$6.0 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 \$41/Bbl after deducting extraction premiums. For the remainder of 2011, management estimates that 14 percent of total extraction volumes will be exposed to frac spread. For fourth quarter 2011, approximately 80 percent of the exposure has been hedged at an average price of \$30.50/Bbl.

During 2012, AltaGas expects producers to continue to focus on maximizing their net backs from liquids-rich natural gas while the price for natural gas remains within its current trading range. Land sales are frequently a leading indicator of future oil and gas field activity. Alberta and B.C. land sales are positioned within these liquids-rich fields such as Monteny and Duvernay. Management has recognized numerous opportunities to expand facilities where there is growing demand for gas processing infrastructure to serve producers in these areas. In areas where AltaGas does not have existing infrastructure, management will continue to work with producers to build new facilities, such as Gordondale.

AltaGas expects 2012 frac spreads will continue to be extremely attractive at approximately \$30/Bbl, but lower than 2011's historic highs as more NGL is produced within Canada and the United States. However, pricing will be largely dependent on demand within the petrochemical and oil sand industries, which fluctuates with global macroeconomics. For 2012, AltaGas has hedged approximately two-thirds of its volumes that are exposed to frac spread at an average price of \$34.50/Bbl.

Gordondale and Harmattan Co-stream facilities will commence operations during 2012. As a result, based on current production, natural gas reserve estimates and expected capital costs, AltaGas expects these projects to contribute annual average EBITDA between \$50 million and \$60 million once completed.

## POWER

### POWER OPERATING STATISTICS

	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Volume of power sold (GWh) <sup>(1)(2)</sup>	760	711	2,227	2,103
Average price realized on the sale of power (\$/MWh) <sup>(1)(2)</sup>	80.67	61.53	74.83	68.37
Alberta Power Pool average spot price (\$/MWh) <sup>(1)</sup>	94.70	35.69	76.26	60.72

<sup>(1)</sup> Average for the period.

<sup>(2)</sup> Includes both Alberta and British Columbia sale of power.

#### Three Months Ended September 30

Operating income for third quarter 2011 was \$21.5 million, an increase of 26 percent compared to \$17.0 million for same period 2010. Operating income increased as a result of higher spot Alberta power prices, the addition of the cogeneration facility at the Harmattan complex, higher generation from the gas-fired peaking plants, and stronger results from Bear Mountain. These increases were partially offset by higher hedging losses, higher PPA costs primarily due to an unfavourable 30-day RAPP, higher environmental compliance costs and higher transmission costs. In third quarter 2011, AltaGas was 68 percent hedged in Alberta at an average price of approximately \$70/MWh. In third quarter 2010, AltaGas was 65 percent hedged at an average price of approximately \$73/MWh.

Net revenue for third quarter 2011 was \$29.6 million compared to \$23.3 million for same period 2010. The increase was primarily due to higher spot Alberta power prices, higher generation from gas-fired peaking plants, the addition of the Harmattan gas-fired cogeneration facility in fourth quarter 2010 and higher power generated at Bear Mountain. The increases were partially offset by higher hedging losses, higher PPA costs due to an unfavorable 30-day (RAPP), higher environmental compliance costs and higher transmission costs.

Operating and administrative expense was \$4.0 million for third quarter 2011 compared to \$2.4 million for same period 2010. The increase was primarily due to the addition of the Harmattan gas-fired cogeneration facility and higher variable costs at the peaking facilities and Bear Mountain.

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

#### Nine Months Ended September 30

Operating income for the first nine months of 2011 was \$63.6 million, a 17 percent increase compared to \$54.3 million for the same period of 2010. Operating income increased as a result of higher spot Alberta power prices, higher generation from gas-fired peaking plants, the addition of the cogeneration facility at the Harmattan complex and stronger results from Bear Mountain. The increases were partially offset by higher hedging losses, higher PPA costs due to an unfavorable 30-day RAPP, higher environmental compliance costs and higher transmission costs. For the first nine months of 2011, AltaGas hedged 60 percent of power sold in Alberta at an average price of \$67/MWh compared to 64 percent hedged at \$72/MWh for the same period of 2010.

Net revenue for the first nine months of 2011 was \$86.3 million compared to \$74.4 million for the same period of 2010. The increase was primarily due to higher spot Alberta power prices, higher generation from gas-fired peaking plants, the addition of the Harmattan gas-fired cogeneration facility in fourth quarter 2010 and higher power generated at Bear Mountain. The increases were partially offset by higher hedging losses, higher PPA costs due to an unfavorable 30-day RAPP, higher environmental compliance costs and higher transmission costs.

Operating and administrative expense was \$10.5 million for the first nine months of 2011 compared to \$8.6 million for the same period of 2010. Amortization expense was \$12.2 million for the first nine months of 2011 compared to \$11.5 million for the same period of 2010. The increases were primarily due to the addition of the Harmattan cogeneration facility.

### Power Outlook

The Power segment is expected to report higher operating income in 2011 compared to 2010 as a result of higher prices and higher volumes generated. AltaGas has hedged approximately 65 percent of power exposed to Alberta power prices at an average price of \$72/MWh for fourth quarter 2011. For 2012, AltaGas is approximately 50 percent hedged at an average price of \$64/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, has increased power prices and power price volatility. Management expects to continue to execute short-term hedges at premium prices to long-term prices.

Current forward prices, as published in daily broker reports, are in the \$90s per MWh for the remainder of 2011 and \$70s 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 for the remainder of 2011 compared to 2010.

### UTILITIES

#### UTILITIES OPERATING STATISTICS

	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Natural gas deliveries - end-use (PJ) <sup>(1)</sup>	2.3	2.3	15.3	12.9
Natural gas deliveries - transportation (PJ) <sup>(1)</sup>	1.1	1.3	3.5	4.0
Service sites <sup>(2)</sup>	75,126	73,531	75,126	73,531
Degree day variance from normal - AUI (%) <sup>(3)</sup>	(33.7)	23.0	6.5	(5.3)
Degree day variance from normal - Heritage Gas (%) <sup>(3)</sup>	(20.9)	(48.1)	(2.8)	(14.3)

<sup>(1)</sup> Petajoule (PJ) is one million gigajoules (GJ).

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

<sup>(3)</sup> 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.

The Utility segment predominantly comprised natural gas distribution rate-regulated utilities, where net income is based on a regulated allowed return on capital invested. Rate-regulated cost-of-service utilities 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 utility. The Utility segment discussion of financial results focuses on operating income, prior the impacts of the cost of debt financing and income tax.

Operating 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 results in stronger first and fourth quarters and weaker second and third quarters. Results 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.

### **Three Months Ended September 30**

The Utility segment reported operating income of \$2.9 million compared to \$3.0 million for same period in 2010. Operating income decreased mainly due to seasonal timing differences between revenue generation and the incurrence of recoverable costs at AUI. Rate base growth of 13 percent at AUI and 24 percent at Heritage Gas increased operating income for third quarter 2011 as compared to 2010.

### **Nine Months Ended September 30**

Operating income for the first nine months of 2011 was \$19.6 million compared to \$13.8 million for the same period of 2010. Operating income increased \$3.6 million due to rate base growth of 13 percent and 24 percent at AUI and Heritage Gas, respectively, \$1.5 million due to colder weather in Alberta and Nova Scotia compared to 2010 and \$0.9 million due to timing differences between revenue generation and the incurrence of recoverable costs at AUI. These increases were partially offset by non-recoverable operating and administrative expenses for the Utility segment.

### **Utilities Outlook**

Rate base growth in its Alberta and Nova Scotia natural gas distribution utilities is expected to drive earnings in 2011 for the Utility segment. 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 \$14 million to expand its system in 2011 which, along with increases in the Revenue Deficiency Account (RDA), is expected to grow rate base by 24 percent. This growth is expected to be partially offset by higher non-recoverable financing costs for the Utility segment.

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 new business growth in 2011 to be approximately one to two percent.

The AUC is currently considering AUI's rate application for 2010, 2011 and 2012. The hearing was held in 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 three-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 over 600 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 for a three-year period beginning January 2012. On October 17, 2011, Heritage Gas entered into a settlement agreement with the active interveners in the proceeding related to the issues in the GTA including 11.0 percent for return on equity and 7.25 percent for debt rate beginning 2012. The settlement agreement was presented to the NSUAR on October 17, 2011 and a decision 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. AltaGas, as operator on behalf of the joint venture partners, is working with consultants to evaluate the reservoir and production options, however it is expected that remaining reserves will be significantly lower than originally expected. 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 September 30**

The operating loss for third quarter 2011 was \$9.4 million compared to \$8.3 million for third quarter 2010. Operating income decreased \$3.2 million due to investment gains realized in 2010 that were not realized in 2011 and \$0.7 million higher amortization expense, partially offset by an unrealized loss of \$1.6 million on an equity investment compared to an unrealized loss of \$2.9 million and lower general and administrative costs than in the same quarter last year.

Operating and administrative expense was \$6.5 million in third quarter 2011 compared to \$8.0 million in third quarter 2010. Lower expenses were a result of cost saving initiatives implemented. Amortization expense was \$1.4 million in third quarter 2011 compared to \$0.7 million in the same quarter 2010. The increase was due to a reallocation of certain capital assets from other operating segments.

### **Nine Months Ended September 30**

The operating loss for the first nine months of 2011 was \$30.9 million compared to \$25.7 million for the same period of 2010. The operating loss increased by \$5.2 million due to lower investment gains realized and income received, \$3.1 million higher unrealized mark-to-market losses on equity investments and \$1.0 million higher amortization expense, partially offset by lower general and administrative costs.

Operating and administrative expense was \$19.7 million in the first nine months of 2011 compared to \$23.7 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 \$3.1 million in the first nine months of 2011 compared to \$2.1 million in the same period of 2010. The increase was due to a reallocation of certain capital assets from other operating segments.

### **Corporate Outlook**

Excluding the impact of mark-to-market accounting, the operating loss for 2011 in the Corporate segment 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.

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 third quarter 2011, AltaGas increased capital assets, long-term investments and other assets by \$109.4 million compared to \$52.8 million in third quarter 2010.

**Invested Capital - Investment Type**
**Three Months Ended  
September 30, 2011**

(\$ millions)	Gas	Power	Utilities	Corporate	Total
<b>Invested capital:</b>					
Capital assets	62.9	33.9	14.5	0.6	111.9
Energy arrangements, contracts and relationships	-	-	-	-	-
Long-term investments and other assets	-	(0.1)	-	(2.4)	(2.5)
	62.9	33.8	14.5	(1.8)	109.4
<b>Disposals:</b>					
Capital assets	-	-	-	-	-
Long-term investments and other assets	-	-	-	-	-
<b>Net Invested capital</b>	<b>62.9</b>	<b>33.8</b>	<b>14.5</b>	<b>(1.8)</b>	<b>109.4</b>

**Invested Capital - Investment Type**
**Three Months Ended  
September 30, 2010**

(\$ millions)	Gas	Power	Utilities	Corporate	Total
<b>Invested capital:</b>					
Capital assets	15.7	11.1	21.8	0.9	49.5
Long-term investments and other assets	0.5	-	-	2.9	3.4
	16.2	11.1	21.8	3.8	52.9
<b>Disposals:</b>					
Capital assets	-	-	-	-	-
Long-term investments and other assets	-	-	-	(0.1)	(0.1)
<b>Net Invested capital</b>	<b>16.2</b>	<b>11.1</b>	<b>21.8</b>	<b>3.7</b>	<b>52.8</b>

**Invested Capital - Investment Type**
**Nine Months Ended  
September 30, 2011**

(\$ millions)	Gas	Power	Utilities	Corporate	Total
<b>Invested capital:</b>					
Capital assets	133.7	84.5	23.3	8.6	250.1
Energy arrangements, contracts and relationships	-	91.3	-	-	91.3
Long-term investments and other assets	-	(0.4)	-	(15.5)	(15.9)
	133.7	175.4	23.3	(6.9)	325.5
<b>Disposals:</b>					
Capital assets	(28.0)	-	-	-	(28.0)
Long-term investments and other assets	-	-	-	(0.3)	(0.3)
<b>Net Invested capital</b>	<b>105.7</b>	<b>175.4</b>	<b>23.3</b>	<b>(7.2)</b>	<b>297.2</b>

## Invested Capital - Investment Type

Nine Months Ended  
September 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
<b>Invested capital:</b>					
Capital assets	77.2	24.5	33.4	4.2	139.3
Long-term investments and other assets	0.5	-	-	(3.0)	(2.5)
	77.7	24.5	33.4	1.2	136.8
<b>Disposals:</b>					
Capital assets	-	-	-	(0.3)	(0.3)
Long-term investments and other assets	(2.4)	-	-	-	(2.4)
<b>Net Invested capital</b>	<b>75.3</b>	<b>24.5</b>	<b>33.4</b>	<b>0.9</b>	<b>134.1</b>

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

Growth capital of \$107.4 million was expended in third quarter 2011 (third quarter 2010 - \$50.2 million). In the Gas segment, growth capital comprised \$35.2 million for the Harmattan Co-stream project, \$12.1 million for the Gordondale Gas Plant, \$4.5 million for Henderson Pipeline, \$1.8 million for Younger A&B Train Demethanizer project and \$8.5 for various Gas projects. Within the Power segment, growth capital projects included \$25.4 million related to Forrest Kerr, \$2.9 million for Harmattan Cogeneration, and \$5.5 million for other renewable power projects under development. Within the Utility segment, growth capital comprised \$9.2 million for AUI and \$5.3 million for Heritage Gas. The Corporate segment growth capital of \$(3.0) million was related to the unrealized mark-to-market loss on a publicly traded company.

Maintenance and administrative capital expenditures in third quarter 2011 were \$0.6 million and \$1.4 million, respectively (third quarter 2010 - \$1.5 million and \$1.2 million, respectively).

Growth capital of \$313.5 million was expended in the first nine months of 2011 (same period 2010 - \$128.3 million). In the Gas segment, growth capital comprised \$64.5 million for assets from the Harmattan Co-stream project, \$24.6 million for Gordondale Gas Plant, \$8.3 million for Henderson Pipeline, \$5.1 million for Ante Creek, \$1.9 million for Younger A&B Train Demethanizer, \$1.8 million for Pouce Coupe Sour Gas facility and \$24.3 million for various Gas-related projects, including Marlboro Gas Plant. Within the Power segment, growth capital projects included \$64.7 million for the Forrest Kerr project, \$10.6 million for Harmattan Cogeneration project and \$8.8 for renewable power development projects. Energy arrangement, contracts and relationships in the Power segment increased by \$91.2 million, of which \$90.0 million related to AltaGas' obligation to BC Hydro in support of the construction and operation of the Northwest Transmission Line. Within the Utilities segment, growth capital included \$11.3 million for AUI, \$6.8 million for Heritage Gas and \$5.2 million for various Utilities-related assets. Corporate segment growth capital of \$(15.6) million was related to an unrealized mark-to-market loss on a publicly traded company.

Maintenance and administrative capital expenditures in the first nine months of 2011 were \$2.3 million and \$9.7 million, respectively (same period 2010 - \$4.4 million and \$4.1 million, respectively).

**Invested Capital - Use****Three Months Ended  
September 30, 2011**

(\$ millions)	Gas	Power	Utilities	Corporate	Total
<b>Invested capital:</b>					
Maintenance	0.6	-	-	-	0.6
Growth	62.1	33.8	14.5	(3.0)	107.4
Administrative	0.2	-	-	1.2	1.4
<b>Invested capital</b>	<b>62.9</b>	<b>33.8</b>	<b>14.5</b>	<b>(1.8)</b>	<b>109.4</b>

## Invested Capital - Use

Three Months Ended  
September 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	1.2	0.3	-	-	1.5
Growth	14.5	10.8	21.8	3.1	50.2
Administrative	0.5	-	-	0.7	1.2
Invested capital	16.2	11.1	21.8	3.8	52.9

## Invested Capital - Use

Nine Months Ended  
September 30, 2011

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	2.2	0.1	-	-	2.3
Growth	130.5	175.3	23.3	(15.6)	313.5
Administrative	0.9	-	-	8.8	9.7
Invested capital	133.6	175.4	23.3	(6.8)	325.5

## Invested Capital - Use

Nine Months Ended  
September 30, 2010

(\$ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	2.1	2.3	-	-	4.4
Growth	75.0	22.2	33.4	(2.3)	128.3
Administrative	0.6	-	-	3.5	4.1
Invested capital	77.7	24.5	33.4	1.2	136.8

## 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 third 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 11.75/MWh to \$999.99/MWh in third quarter 2011 and \$0.00/MWh to \$653.36/MWh in same quarter last year. The average Alberta spot price was \$94.70/MWh in third quarter 2011 (third quarter 2010 - \$35.69/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average price realized for power by AltaGas was \$80.67/MWh in third quarter (third quarter 2010 - \$61.53/MWh). AltaGas has hedged approximately 65 percent of power exposed to Alberta power prices at an average price of \$72/MWh for the fourth quarter of 2011. For 2012, AltaGas is approximately 50 percent hedged at an average price of \$64/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 third 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 third quarter 2011 was \$42.15/Bbl (third quarter 2010 - \$26.86/Bbl). NGL sales during the third quarter were impacted by the Younger turnaround as a result of the commercial arrangement surrounding this facility. The average NGL frac spread realized by AltaGas in third quarter 2011 was \$22.95/Bbl (third quarter 2010 - \$24.02/Bbl). The Corporation has hedged an average of 4,625 Bbls/d, or approximately 80 percent of volumes that are exposed to spot prices for fourth quarter 2011, at an average price of \$30.50/Bbl. For 2012, AltaGas has hedged approximately two-thirds of volumes that are exposed to frac spread at an average price of \$34.50/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 September 30, 2011, the Corporation had interest rate swaps for \$40 million with varying terms to maturity until March 31, 2012. At September 30, 2011, the Corporation had fixed the interest rate on 97 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.

On September 19, 2011, AltaGas amended and extended the Utility Group's \$200 million unsecured, extendible revolving credit facility with a syndicate of Canadian chartered banks. The credit facility's term was extended to four years with a new maturity date of November 17, 2015.

On October 17, 2011, AltaGas issued \$200 million of senior unsecured medium term notes. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019.

<b>Cash Flows</b>	Three Months Ended		Nine Months Ended	
	September 30		September 30	
(\$ millions)	2011	2010	2011	2010
Cash from operations	65.0	70.4	151.5	142.2
Investing activities	(112.7)	(48.9)	(235.8)	(106.1)
Financing activities	40.1	(18.6)	85.1	(36.1)
Change in cash	(7.6)	2.9	0.8	-

### Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was \$65.0 million in third quarter 2011 compared to \$70.4 million in third quarter 2010. The decrease in cash from operations was primarily a result of lower non-cash working capital which was driven by higher inventory, partially offset by higher funds from operations.

<b>Working Capital</b>	September 30	September 30
	2011	2010
(\$ millions except current ratio)		
Current assets	304.6	267.4
Current liabilities	471.6	401.7
Working capital	(167.0)	(134.3)
Current ratio	0.65	0.67

Working capital was in a deficit position of \$167.0 million at September 30, 2011, compared to a deficit position of \$134.3 million at September 30, 2010. The working capital ratio was 0.65 at September 30, 2011 compared to 0.67 at September 30, 2010. The working capital ratio decreased due to an increase in accounts payable partially offset by an increase in accounts receivable and decrease in current portion of long-term debt.

### Investing Activities

Cash used for investing activities in third quarter 2011 was \$112.7 million compared to \$48.9 million in third quarter 2010. Investing activities in the quarter were mainly comprised of capital asset expenditures of \$89.9 million, payments for energy arrangements of \$18.1 million and investments in regulatory assets of \$4.8 million.

### Financing Activities

Cash received from financing activities was \$40.1 million in third quarter 2011 compared to cash used for financing activities of \$18.6 million in third quarter 2010. The change in financing activities was due to the net issuance of revolving long-term debt in third quarter 2011 compared to the net repayment of long-term debt in same period 2010 as well as higher payout to shareholders in third quarter 2011 compared to same period 2010.

### 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 September 30, 2011, AltaGas had total debt outstanding of \$1,052.3 million, up from \$904.5 million at December 31, 2010. At September 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 September 30, 2011, AltaGas had drawn bank debt of \$67.1 million and letters of credit outstanding of \$180.5 million against the extendible revolving letter of credit facility, the syndicated credit facilities and the demand operating facilities. As at September 30, 2011, the Corporation had \$823.4 million in available credit facilities and \$2.9 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 September 30, 2011, AltaGas' current portion of long-term debt was \$101.6 million. The Corporation has a \$100 million MTN maturing in January of 2012.

AltaGas' earnings interest coverage for the rolling 12 months ended September 30, 2011 was 2.64 times.

Credit facilities (\$ millions)	Borrowing capacity	Drawn at September 30 2011	Drawn at December 31 2010
Demand operating facilities	196.0	116.2	7.9
Extendible revolving letter of credit facility	75.0	64.3	50.5
AltaGas Ltd. revolving credit facility <sup>(1)</sup>	600.0	-	-
Utility Group revolving credit facility <sup>(2)</sup>	200.0	67.1	114.5
	1,071.0	247.6	172.9

<sup>(1)</sup> Revolving credit facility maturing May 30, 2015.

<sup>(2)</sup> Revolving credit facility maturing November 17, 2015.

At September 30, 2011, AltaGas held a \$75 million (December 31, 2010 - \$75.0 million) unsecured four-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 September 30, 2011, AltaGas had letters of credit of \$64.3 million (December 31, 2010 - \$50.5 million) outstanding against the extendible revolving letter of credit facility. As at September 30, 2011, AltaGas held \$196 million (December 31, 2010 - \$71 million) in demand operating and demand letter of credit facilities. As at September 30, 2011, AltaGas had draws and letters of credit of \$116.2 million (December 31, 2010 - \$7.9 million) outstanding against the demand facilities.

The Utility Group has a \$200 million, four-year revolving credit facility maturing on November 17, 2015. 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 September 30, 2011, AltaGas had \$67.1 million of 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 third quarter 2011 (third 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 September 30, 2011, AltaGas had 83.8 million common shares outstanding and a market capitalization of \$2.2 billion based on a closing trading price on September 30, 2011, of \$27.08 per share. At September 30, 2011, there were 4.6 million options outstanding and 1.5 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 third quarter 2011, AltaGas declared dividends of \$27.6 million (third quarter 2010 dividends - \$29.2 million).

For the first nine months of 2011, AltaGas declared dividends of \$82.4 million. Including both distributions before the corporate conversion and dividends after, for the nine months ended September 30, 2010, AltaGas declared distributions and dividends of \$113.9 million.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to \$0.115 per common share from \$0.11 per common share. The first monthly dividend of \$0.115 per common share is payable on or after December 15, 2011 to common shareholders of record at close of business on November 25, 2011.

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 <sup>(1)</sup>	0.33	0.33
Fourth quarter	-	0.33
<b>Total</b>	<b>0.99</b>	<b>1.74</b>

<sup>(1)</sup> 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 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.

#### SUBSEQUENT EVENT

On October 17, 2011, AltaGas issued \$200 million of senior unsecured medium term notes. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019. Net proceeds from the issuance will be used to reduce outstanding indebtedness and for general corporate purposes. The unsecured medium-term notes are rated BBB by both Standard & Poor's Rating Services and DBRS Limited.

#### CHANGES IN ACCOUNTING POLICIES

##### ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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 one-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.

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.

The assessment comparing the most significant differences between US GAAP and CGAAP determined the impact the accounting policies, financial statements, information systems, internal controls and other business activities for AltaGas. Based on the work completed, the differences identified are limited to:

- Accounting for business combinations;
- Pension and other post-employment benefits;
- Accounting for joint ventures;
- Hedge accounting;
- Inventory for natural gas held in storage; and
- Presentation of deferred financing costs

The assessment of the differences may change prior to the US GAAP conversion date as a result of the issuance of new accounting standards or amendments to existing accounting standards, changes in regulation or economic conditions or other factors specific to AltaGas' business activities.

Debt covenants and other agreements are under review to determine what changes are required upon adoption of US GAAP and, where changes are necessary, shall be amended prior to adoption of US GAAP on January 1, 2012.

Education and training activities have occurred throughout the project and will continue in the fourth quarter 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 nine months ended September 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 third 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)	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09
Total revenue	<b>369.6</b>	368.1	403.4	362.2	297.4	334.0	360.5	336.4
Net revenue <sup>(1)</sup>	<b>117.9</b>	113.7	137.7	130.7	102.6	124.8	127.2	115.4
Operating income <sup>(1)</sup>	<b>33.4</b>	34.3	58.5	47.6	32.6	35.6	37.4	46.0
Net income before taxes	<b>17.1</b>	16.0	38.1	35.4	10.3	26.3	31.0	29.2
Net income applicable to common shares	<b>10.6</b>	16.6	26.6	26.5	6.0	28.4	36.4	32.1
(\$ per share)	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09
Net income applicable to common shares								
Basic	<b>0.13</b>	0.20	0.32	0.32	0.07	0.35	0.45	0.40
Diluted	<b>0.12</b>	0.20	0.31	0.32	0.07	0.35	0.45	0.40
Distributions / dividends declared	<b>0.33</b>	0.33	0.33	0.33	0.33	0.54	0.54	0.54

<sup>(1)</sup> 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.
- In third quarter 2011, turnarounds at Harmattan and Younger reduced revenue and increased operating expenses by approximately \$6.0 million before taxes. These turnarounds have occurred every three years.

# Consolidated Balance Sheets

(unaudited)

(\$ thousands)	September 30 2011	December 31 2010
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 2,946	\$ 2,109
Accounts receivable	221,831	224,370
Inventory	7,873	13,107
Restricted cash holdings from customers	19,470	17,624
Regulatory assets	682	2
Risk management	45,576	41,226
Prepaid expense and other current assets	6,248	5,587
	<b>304,626</b>	<b>304,025</b>
<b>Capital assets</b>	<b>2,157,707</b>	<b>1,995,632</b>
<b>Energy arrangements, contracts and relationships</b>	<b>204,505</b>	<b>120,848</b>
<b>Goodwill</b>	<b>199,497</b>	<b>199,497</b>
<b>Regulatory assets</b>	<b>87,119</b>	<b>76,515</b>
<b>Risk management</b>	<b>19,093</b>	<b>22,587</b>
<b>Long-term investments and other assets</b> <i>(note 7)</i>	<b>15,080</b>	<b>32,588</b>
	<b>\$ 2,987,627</b>	<b>\$ 2,751,692</b>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current liabilities</b>		
Accounts payable and accrued liabilities	\$ 270,286	\$ 228,772
Dividends payable	9,222	9,078
Short-term debt	2,662	9,478
Current portion of long-term debt <i>(note 5)</i>	101,593	1,508
Customer deposits	23,057	21,432
Regulatory liabilities	1,785	1,494
Risk management	54,352	39,209
Other current liabilities	8,681	12,302
	<b>471,638</b>	<b>323,273</b>
<b>Long-term debt</b> <i>(note 5)</i>	<b>948,028</b>	<b>893,498</b>
<b>Asset retirement obligations</b>	<b>41,145</b>	<b>39,516</b>
<b>Future income taxes</b>	<b>242,308</b>	<b>233,763</b>
<b>Regulatory liabilities</b>	<b>20,059</b>	<b>18,518</b>
<b>Risk management</b>	<b>19,155</b>	<b>20,598</b>
<b>Other long-term liabilities</b> <i>(note 8)</i>	<b>28,821</b>	<b>20</b>
<b>Future employee obligations</b>	<b>12,598</b>	<b>11,475</b>
	<b>1,783,752</b>	<b>1,540,661</b>
<b>Shareholders' equity</b>	<b>1,203,875</b>	<b>1,211,031</b>
	<b>\$ 2,987,627</b>	<b>\$ 2,751,692</b>

See accompanying notes to the unaudited Consolidated Financial Statements.

# Consolidated Statements of Income

(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
<i>(\$ thousands except per share amounts)</i>	<b>2011</b>	2010	<b>2011</b>	2010
<b>REVENUE</b>				
Operating	<b>\$ 374,628</b>	\$ 307,400	<b>\$ 1,164,673</b>	\$ 992,965
Unrealized gain (loss) on risk management contracts <i>(note 7)</i>	<b>(3,531)</b>	(10,424)	<b>(15,514)</b>	(1,312)
Other revenue (expenses)	<b>(1,496)</b>	378	<b>(8,039)</b>	234
	<b>369,601</b>	297,354	<b>1,141,120</b>	991,887
<b>EXPENSES</b>				
Cost of sales	<b>251,693</b>	194,755	<b>771,797</b>	637,221
Operating and administrative	<b>65,004</b>	58,536	<b>191,140</b>	181,458
Accretion of asset retirement obligations	<b>608</b>	716	<b>1,824</b>	2,161
Amortization:				
Capital assets	<b>19,832</b>	18,657	<b>58,137</b>	59,287
Energy arrangements, contracts and relationships	<b>2,571</b>	2,491	<b>7,606</b>	7,473
	<b>339,708</b>	275,155	<b>1,030,504</b>	887,600
<b>Foreign exchange loss (gain)</b>	<b>65</b>	(224)	<b>77</b>	(15)
<b>Interest expense</b>				
Short-term debt	<b>1,449</b>	369	<b>4,360</b>	1,253
Long-term debt	<b>11,320</b>	11,803	<b>35,027</b>	35,506
<b>Income before income taxes</b>	<b>17,059</b>	10,251	<b>71,152</b>	67,543
<b>Income tax expense (recovery)</b>				
Current	<b>(518)</b>	451	<b>797</b>	940
Future	<b>4,250</b>	2,529	<b>8,406</b>	(5,429)
<b>Net income</b>	<b>13,327</b>	7,271	<b>61,949</b>	72,032
Preferred share dividends (net of tax)	<b>2,750</b>	1,266	<b>8,250</b>	1,266
<b>Net income applicable to common shares</b>	<b>\$ 10,577</b>	\$ 6,005	<b>\$ 53,699</b>	\$ 70,766
<b>Net income per share <i>(note 10)</i></b>				
Basic	<b>\$ 0.13</b>	\$ 0.07	<b>\$ 0.65</b>	\$ 0.87
Diluted	<b>\$ 0.12</b>	\$ 0.07	<b>\$ 0.64</b>	\$ 0.87
<b>Weighted average number of shares outstanding (thousands) <i>(notes 9 and 10)</i></b>				
Basic	<b>83,628</b>	81,734	<b>83,188</b>	81,283
Diluted	<b>84,813</b>	82,191	<b>84,242</b>	81,624

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		Nine Months Ended	
	September 30		September 30	
	<b>2011</b>	2010	<b>2011</b>	<b>2010</b>
<b>Net income</b>	<b>\$ 13,327</b>	\$ 7,271	<b>\$ 61,949</b>	\$ 72,032
<b>Other comprehensive income (loss), net of tax</b>				
Unrealized net (loss) on available-for-sale financial assets	<b>(1,282)</b>	(1,183)	<b>(6,510)</b>	(4,580)
Unrealized net gain (loss) gain on derivatives designated as cash flow hedges	<b>624</b>	(3,229)	<b>(1,782)</b>	(9,383)
Reclassification to net income of net gain on derivatives designated as cash flow hedges pertaining to prior periods	<b>159</b>	1,590	<b>724</b>	(7,137)
	<b>(499)</b>	(2,822)	<b>(7,568)</b>	(21,100)
<b>Comprehensive income</b>	<b>\$ 12,828</b>	\$ 4,449	<b>\$ 54,381</b>	\$ 50,932
<b>Accumulated other comprehensive (loss) income, beginning of period</b>	<b>\$ (9,821)</b>	\$ 2,947	<b>\$ (2,752)</b>	\$ 21,225
<b>Other comprehensive loss, net of tax</b>	<b>(499)</b>	(2,822)	<b>(7,568)</b>	(21,100)
<b>Accumulated other comprehensive (loss) income, end of period <i>(note 7)</i></b>	<b>\$ (10,320)</b>	\$ 125	<b>\$ (10,320)</b>	\$ 125

See accompanying notes to the unaudited Consolidated Financial Statements.

# Consolidated Statements of Shareholders' Equity

(unaudited)

Nine Months Ended  
September 30

<i>(\$ thousands)</i>	<b>2011</b>	<b>2010</b>
<b>Common shares</b>		
Balance, beginning of period	\$ 1,023,033	-
Shares issued pursuant to the Arrangement - July 1, 2010	-	1,005,722
Shares issued for cash on exercise of options	3,186	332
Shares issued under DRIP <sup>(1)</sup>	26,661	5,212
<b>Balance, end of period</b>	<b>1,052,880</b>	<b>1,011,266</b>
<b>Preferred shares</b>		
Balance, beginning of period	194,126	-
Shares issued on public offering (net of issuance costs)	-	194,126
<b>Balance, end of period</b>	<b>194,126</b>	<b>194,126</b>
<b>Contributed surplus</b>		
Balance, beginning of period	5,672	5,621
Amortization of share options	1,334	342
Exercise of share options	(1,892)	(286)
Cancellation of share options	(159)	(49)
Other adjustments	-	1,106
<b>Balance, end of period</b>	<b>4,955</b>	<b>6,734</b>
<b>Warrants</b>		
Balance, beginning of period	-	4,500
Exercised	-	(4,500)
<b>Balance, end of period</b>	<b>-</b>	<b>-</b>
<b>Accumulated earnings</b>		
Balance, beginning of period	(9,048)	34,849
Net income	61,949	72,032
Distributions	-	(84,734)
Common share dividends	(82,417)	(29,235)
Preferred share dividends (net of tax)	(8,250)	(1,266)
Prior period adjustment	-	(58)
<b>Balance, end of period</b>	<b>(37,766)</b>	<b>(8,412)</b>
<b>Accumulated other comprehensive (loss) income</b>		
Balance, beginning of period	(2,752)	21,225
Other comprehensive loss	(7,568)	(21,100)
<b>Balance, end of period</b>	<b>(10,320)</b>	<b>125</b>
<b>Total shareholders' equity</b>	<b>\$ 1,203,875</b>	<b>\$ 1,203,839</b>

<sup>(1)</sup> 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 September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
<b>Cash from operations</b>				
Net income	\$ 13,327	\$ 7,271	\$ 61,949	\$ 72,032
Items not involving cash:				
Amortization	22,403	21,149	65,743	66,760
Accretion of asset retirement obligations	608	716	1,824	2,161
Share-based compensation	(236)	(12)	(717)	7
Future income tax expense (recovery)	4,250	2,529	8,406	(5,429)
(Gain) on sale of assets	-	(3,180)	(6,172)	(5,035)
Equity (income)	-	(256)	-	(256)
Unrealized losses on risk management contracts	3,532	10,424	15,514	1,312
Unrealized losses on held-for-trading investments	1,553	2,895	8,113	5,046
Other	494	128	1,904	1,350
Non-operating investment income	-	(157)	-	(840)
Asset retirement obligations settled	-	(178)	(195)	(273)
Net change in non-cash working capital <i>(note 12)</i>	19,032	29,059	(4,871)	5,354
	<b>64,963</b>	<b>70,388</b>	<b>151,498</b>	<b>142,189</b>
<b>Investing activities</b>				
Change in restricted cash holdings from customers	(53)	3,051	(1,845)	5,018
Capital expenditures	(89,948)	(52,265)	(221,505)	(92,394)
Disposition of capital assets	-	320	13,400	320
Acquisition of energy arrangements, contracts and relationships	(18,052)	(1,324)	(21,976)	(1,863)
Investment in regulatory assets	(4,774)	(5,221)	(4,196)	(9,108)
Distributions from equity investments	148	169	334	288
Disposition of short-term investments	-	10,767	-	15,483
Income from short-term investment	-	157	-	840
Business acquisition	-	-	-	(22,719)
Acquisition of long-term investments and other assets	-	(4,598)	-	(4,839)
Disposition of long-term investments and other assets	-	-	-	2,871
	<b>(112,679)</b>	<b>(48,944)</b>	<b>(235,788)</b>	<b>(106,103)</b>
<b>Financing activities</b>				
Issuance (repayment) of short-term debt	(1,626)	23,212	(6,816)	9,460
Net issuance (repayment) of revolving long-term debt	62,408	(119,676)	(43,148)	(240,656)
Net issuance (repayment) of long-term debt	(275)	(100,484)	197,763	97,585
Dividends and distributions	(31,070)	(21,374)	(92,772)	(121,870)
Net proceeds from issuance of common shares	10,675	5,595	30,100	25,261
Net proceeds from issuance of preferred shares	-	194,126	-	194,126
	<b>40,112</b>	<b>(18,601)</b>	<b>85,127</b>	<b>(36,094)</b>
<b>Change in cash and cash equivalents</b>	<b>(7,604)</b>	<b>2,843</b>	<b>837</b>	<b>(8)</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>10,550</b>	<b>733</b>	<b>2,109</b>	<b>3,584</b>
<b>Cash and cash equivalents, end of period</b>	<b>\$ 2,946</b>	<b>\$ 3,576</b>	<b>\$ 2,946</b>	<b>\$ 3,576</b>

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**

### **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	1 - 24 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.

##### **Adoption of United States Generally Accepted Accounting Principles**

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 one-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

	<b>September 30</b>	December 31
	<b>2011</b>	2010
Credit facilities	<b>\$ 67,089</b>	\$ 113,789
Medium-term notes	<b>975,000</b>	775,000
Loan from Province of Nova Scotia	<b>4,675</b>	4,535
Capital lease obligations	<b>4,958</b>	6,076
Promissory note	<b>4,325</b>	-
Other long-term debt	<b>612</b>	807
Unamortized deferred financing	<b>(7,038)</b>	(5,201)
	<b>1,049,621</b>	895,006
Less current portion	<b>101,593</b>	1,508
	<b>\$ 948,028</b>	\$ 893,498

### Credit Facilities

At September 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. On September 19, 2011, AltaGas amended this facility to a four-year term maturing on November 17, 2015. 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 September 30, 2011, AltaGas had \$67.1 million of 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 September 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 September 30, 2011, AltaGas had letters of credit of \$64.3 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 September 30, 2011, AltaGas had \$116.2 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 approximately 50 percent. AltaGas' debt-to-total capitalization ratio as at September 30, 2011, was 46.6 percent (December 31, 2010 - 42.7 percent).

	September 30 2011	December 31 2010
Debt		
Short-term debt	\$ 2,662	\$ 9,478
Current portion of long-term debt	101,593	1,508
Long-term debt	948,028	893,498
Less cash and cash equivalent	(2,946)	(2,109)
	<b>1,049,337</b>	902,375
Shareholders' equity	<b>1,203,875</b>	1,211,031
Total capitalization	<b>\$ 2,253,212</b>	\$ 2,113,406
Debt-to-total capitalization ratio (%)	<b>46.6</b>	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 September 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		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Natural gas	\$ (1,773)	\$ (5,038)	\$ (6,030)	\$ 1,025
Storage optimization	(120)	633	(1,369)	716
NGL Frac Spread	(1,508)	(6,062)	(5,099)	(4,608)
Power	(844)	(61)	(3,417)	1,612
Heat rate	406	92	602	(54)
Interest rate swaps	(26)	59	(205)	401
Foreign exchange	334	(47)	4	(404)
	<b>\$ (3,531)</b>	<b>\$ (10,424)</b>	<b>\$ (15,514)</b>	<b>\$ (1,312)</b>

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

	Unrealized		Nine Months Ended September 30 2011		Unrealized gains Tax (expense) recovery		Nine Months Ended September 30 2010	
	(losses)	Tax recovery			(losses)	recovery		
NGL Frac Spread	\$ (1,021)	\$ 255	\$ (766)	\$ (3,509)	\$ 965	\$ (2,544)		
Power	(3,555)	890	(2,665)	8,110	(2,290)	5,820		
Bond forward	(1,834)	-	(1,834)	(2,449)	-	(2,449)		
Available-for-sale	(5,777)	722	(5,055)	(797)	95	(702)		
OCI	\$ (12,187)	\$ 1,867	\$ (10,320)	\$ 1,355	\$ (1,230)	\$ 125		

**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 a pre-tax unrealized loss of \$1.4 million for third quarter 2011 (third quarter 2010 - unrealized loss of \$1.4 million).

In July 2009, AltaGas purchased additional shares of Alterra as part of its initial public offering. These shares were classified as held-for-trading. In July 2010, AltaGas purchased another tranche of common shares in Alterra, which were classified as held-for-trading. In third quarter 2011, AltaGas recognized a pre-tax unrealized loss of \$1.6 million in the Corporate segment (third quarter 2010 - unrealized loss \$2.9 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 September 30, 2011, AltaGas is obligated to pay approximately \$69.3 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 \$40.5 million and \$28.8 million in other long-term liabilities.

**9. SHAREHOLDERS' CAPITAL**

**Authorization**

At September 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 five-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 five-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.

<b>Common Shares Issued and Outstanding</b>	Number of shares	Amount
December 31, 2010	<b>82,526,399</b>	<b>\$ 1,023,033</b>
Shares issued for cash on exercise of options	<b>221,060</b>	<b>3,186</b>
Shares issued under DRIP	<b>1,092,906</b>	<b>26,661</b>
<b>Issued and outstanding at September 30, 2011</b>	<b>83,840,365</b>	<b>\$ 1,052,880</b>

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.

<b>Weighted Average Shares Outstanding</b>	Three Months Ended		Nine Months Ended	
	2011	September 30 2010	2011	September 30 2010
Number of shares - basic	<b>83,628,314</b>	81,733,759	<b>83,187,526</b>	81,283,418
Dilutive equity instruments <sup>(1)</sup>	<b>1,185,120</b>	457,248	<b>1,054,025</b>	340,687
Number of shares - diluted	<b>84,813,434</b>	82,191,007	<b>84,241,551</b>	81,624,105

<sup>(1)</sup> 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 September 30, 2011, 3,810,971 shares were reserved for issuance under the plan. As at September 30, 2011, options granted under the plan generally had a term of 8 years until expiry and vested no longer than over a four-year period.

At September 30, 2011, outstanding options were exercisable at various dates within the next ten years. As at September 30, 2011, the unexpensed fair value of share option compensation cost associated with future periods was \$2.2 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 <sup>(1)</sup>
Share options outstanding, December 31, 2010	4,858,500	\$ 20.25
Granted	174,000	25.93
Exercised	(219,810)	16.28
Cancelled	(239,625)	21.16
<b>Share options outstanding, September 30, 2011</b>	<b>4,573,065</b>	<b>\$ 20.62</b>
<b>Share options exercisable, September 30, 2011</b>	<b>1,534,753</b>	<b>\$ 23.38</b>

<sup>(1)</sup> Weighted average.

The following table summarizes the employee share option plan as at September 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	797,665	\$ 14.09	7.11	207,603	\$ 14.01	
\$15.26 to \$25.08	3,021,900	20.59	8.18	699,150	22.13	
\$25.09 to \$29.15	753,500	27.65	5.68	628,000	27.87	
	4,573,065	\$ 20.62	7.17	1,534,753	\$ 23.38	

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 third quarter 2011 in respect of this plan was \$2.3 million (third quarter 2010 - \$2.8 million). As at September 30, 2011, the unexpensed fair value of equity-based compensation costs associated with future periods was \$13.9 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 September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Numerator:				
Net income applicable to common shares - basic	\$ 10,577	\$ 6,005	\$ 53,699	\$ 70,766
Net income applicable to common shares - diluted	\$ 10,577	\$ 6,005	\$ 53,699	\$ 70,766
Denominator:				
Weighted-average number of shares	83,628	81,734	83,188	81,283
Dilutive equity instruments <sup>(1)</sup>	1,185	457	1,054	341
Number of shares outstanding - diluted	84,813	82,191	84,242	81,624
Basic net income applicable to common shares	\$ 0.13	\$ 0.07	\$ 0.65	\$ 0.87
Diluted net income per share	\$ 0.12	\$ 0.07	\$ 0.64	\$ 0.87

<sup>(1)</sup> 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		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Accounts receivable	\$ (6,792)	\$ 21,105	\$ 2,539	\$ 39,633
Inventory	(6,350)	(7,604)	5,234	(10,926)
Other current assets	1,300	7,075	(661)	1,462
Regulatory assets	(384)	(136)	(680)	1,980
Accounts payable and accrued liabilities	71,338	9,110	41,514	(4,127)
Dividends payable	49	-	144	-
Customer deposits	53	(2,914)	1,625	(4,831)
Regulatory liabilities	(435)	(74)	291	(580)
Other current liabilities	1,958	489	(3,621)	(2,781)
	60,737	27,051	46,385	19,830
Add back: (decrease) in capital costs payable	(41,705)	2,008	(51,256)	(14,476)
Net change in non-cash working capital	\$ 19,032	\$ 29,059	\$ (4,871)	\$ 5,354

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

	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Interest paid	\$ 14,260	\$ 14,339	\$ 35,459	\$ 41,153
Income taxes paid	\$ 160	\$ 318	\$ 2,910	\$ 1,687

## 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		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Defined contribution plan	\$ 635	\$ 628	\$ 1,916	\$ 1,948
Defined benefit plan	1,799	558	2,115	1,518
Supplemental executive retirement plan	(545)	396	1,382	1,131
Other post-retirement benefit plans	65	65	226	226
	\$ 1,954	\$ 1,647	\$ 5,639	\$ 4,823

## 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 October 17, 2011, AltaGas issued \$200 million of senior unsecured medium term notes. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019. Net proceeds from the issuance will be used to reduce outstanding indebtedness and for general corporate purposes. The unsecured medium-term notes are rated BBB by both Standard & Poor's Rating Services and DBRS Limited.

## 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:

<b>Gas</b>	<ul style="list-style-type: none"><li>– NGL processing and extraction plants</li><li>– transmission pipelines to transport natural gas and NGL</li><li>– natural gas gathering lines and field processing facilities</li><li>– energy consulting and sale of natural gas and electricity</li><li>– natural gas storage facilities</li></ul>
<b>Power</b>	<ul style="list-style-type: none"><li>– coal-fired and gas-fired power output under power purchase arrangements and other agreements</li><li>– gas-fired power plants</li><li>– wind and run-of-river power plants</li><li>– sale of power to commercial and industrial users in Alberta</li></ul>
<b>Utilities</b>	<ul style="list-style-type: none"><li>– regulated natural gas distribution assets</li><li>– production of natural gas to serve the power generation and heating needs of the town of Inuvik, Northwest Territories</li></ul>
<b>Corporate</b>	<ul style="list-style-type: none"><li>– 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</li></ul>

The following tables show the composition by segment:

<b>Three Months Ended September 30, 2011</b>	<b>Gas</b>	<b>Power</b>	<b>Utilities</b>	<b>Corporate</b>	<b>Intersegment Elimination</b>	<b>Total</b>
Revenue	\$ 270,802	\$ 103,176	\$ 22,798	\$ (1,495)	\$ (22,149)	\$ 373,132
Unrealized losses on risk management	-	-	-	(3,531)	-	(3,531)
Cost of sales	(193,147)	(73,575)	(6,753)	-	21,782	(251,693)
Operating and administrative	(44,808)	(4,004)	(10,081)	(6,478)	367	(65,004)
Accretion of asset retirement obligations	(596)	(12)	-	-	-	(608)
Amortization	(13,842)	(4,110)	(3,083)	(1,368)	-	(22,403)
Foreign exchange gain	-	-	-	(65)	-	(65)
Interest expense	-	-	(2,951)	(9,818)	-	(12,769)
<b>Income (loss) before income taxes</b>	<b>\$ 18,409</b>	<b>\$ 21,475</b>	<b>\$ (70)</b>	<b>\$ (22,755)</b>	<b>-</b>	<b>\$ 17,059</b>
Net additions (reductions) to:						
Capital assets <sup>(1)</sup>	\$ 63,171	\$ 33,864	\$ 14,533	\$ 610	-	\$ 112,178
Energy arrangements, contracts and relationships	\$ (1,007)	\$ (1,512)	-	-	-	\$ (2,519)
Long-term investment and other assets <sup>(1)</sup>	\$ (6,657)	\$ 3,561	\$ (62)	-	-	\$ (3,158)
Goodwill	\$ 143,726	-	\$ 55,771	-	-	\$ 199,497
<b>Segmented assets</b>	<b>\$ 1,735,412</b>	<b>\$ 657,964</b>	<b>\$ 493,130</b>	<b>\$ 101,121</b>	<b>-</b>	<b>\$ 2,987,627</b>

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

<b>Nine Months Ended September 30, 2011</b>	<b>Gas</b>	<b>Power</b>	<b>Utilities</b>	<b>Corporate</b>	<b>Intersegment Elimination</b>	<b>Total</b>
Revenue	\$ 880,306	\$ 260,905	\$ 117,935	\$ (8,039)	\$ (94,473)	\$ 1,156,634
Unrealized losses on risk management	-	-	-	(15,514)	-	(15,514)
Cost of sales	(633,559)	(174,575)	(56,600)	-	92,937	(771,797)
Operating and administrative	(129,958)	(10,496)	(32,513)	(19,709)	1,536	(191,140)
Accretion of asset retirement obligations	(1,788)	(36)	-	-	-	(1,824)
Amortization	(41,192)	(12,210)	(9,205)	(3,136)	-	(65,743)
Foreign exchange loss	-	-	-	(77)	-	(77)
Interest expense	-	-	(8,714)	(30,673)	-	(39,387)
<b>Income (loss) before income taxes</b>	<b>\$ 73,809</b>	<b>\$ 63,588</b>	<b>\$ 10,903</b>	<b>\$ (77,148)</b>	<b>-</b>	<b>\$ 71,152</b>
Net additions (reductions) to:						
Capital assets <sup>(1)</sup>	\$ 105,130	\$ 84,492	\$ 30,840	\$ 1,689	-	\$ 222,151
Energy arrangements, contracts and relationships	\$ (3,021)	\$ 86,678	-	-	-	\$ 83,657
Long-term investment and other assets <sup>(1)</sup>	\$ (19,046)	\$ 2,837	\$ (335)	\$ (964)	-	\$ (17,508)
Goodwill	\$ 143,726	-	\$ 55,771	-	-	\$ 199,497
<b>Segmented assets</b>	<b>\$ 1,735,412</b>	<b>\$ 657,964</b>	<b>\$ 493,130</b>	<b>\$ 101,121</b>	<b>-</b>	<b>\$ 2,987,627</b>

Three Months Ended  
September 30, 2010

	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 243,919	\$ 58,618	\$ 22,135	\$ 379	\$ (17,273)	\$ 307,778
Unrealized losses on risk management	-	-	-	(10,424)	-	(10,424)
Cost of sales	(168,270)	(35,328)	(7,347)	-	16,190	(194,755)
Operating and administrative	(40,245)	(2,449)	(8,965)	(7,960)	1,083	(58,536)
Accretion of asset retirement obligations	(708)	(8)	-	-	-	(716)
Amortization	(13,748)	(3,818)	(2,859)	(723)	-	(21,148)
Foreign exchange (loss)	-	-	-	224	-	224
Interest expense	-	-	(1,824)	(10,348)	-	(12,172)
<b>Income (loss) before income taxes</b>	<b>\$ 20,948</b>	<b>\$ 17,015</b>	<b>\$ 1,140</b>	<b>\$ (28,852)</b>	<b>-</b>	<b>\$ 10,251</b>
Net additions to:						
Capital assets <sup>(1)</sup>	\$ 16,111	\$ 11,036	\$ 21,372	\$ 914	-	\$ 49,433
Energy arrangements, contracts and relationships	\$ -	\$ 1,324	-	-	-	\$ 1,324
Long-term investment and other assets <sup>(1)</sup>	\$ 409	\$ 87	\$ 53	\$ 2,804	-	\$ 3,353
Goodwill	\$ 143,726	-	\$ 56,076	-	-	\$ 199,802
Segmented assets	\$ 1,657,938	\$ 437,313	\$ 438,768	\$ 118,631	-	\$ 2,652,650

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

Nine Months Ended  
September 30, 2010

	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	\$ 784,434	\$ 194,875	\$ 105,582	\$ 234	\$ (91,926)	\$ 993,199
Unrealized gains on risk management	-	-	-	(1,312)	-	(1,312)
Cost of sales	(551,220)	(120,427)	(55,703)	-	90,129	(637,221)
Operating and administrative	(122,997)	(8,646)	(27,867)	(23,732)	1,797	(181,445)
Accretion of asset retirement obligations	(2,137)	(24)	-	-	-	(2,161)
Amortization	(44,893)	(11,464)	(8,249)	(2,154)	-	(66,760)
Foreign exchange gain	-	-	-	15	-	15
Interest expense	-	-	(5,183)	(31,576)	-	(36,759)
<b>Income (loss) before income taxes</b>	<b>\$ 63,187</b>	<b>\$ 54,314</b>	<b>\$ 8,580</b>	<b>\$ (58,525)</b>	<b>-</b>	<b>\$ 67,556</b>
Net additions to:						
Capital assets <sup>(1)</sup>	\$ 77,326	\$ 24,520	\$ 33,258	\$ 3,924	-	\$ 139,028
Energy arrangements, contracts and relationships	-	\$ 1,863	-	-	-	\$ 1,863
Long-term investment and other assets <sup>(1)</sup>	(2,630)	(31)	740	(2,962)	-	(4,883)
Goodwill	\$ 143,726	-	\$ 56,076	-	-	\$ 199,802
Segmented assets	\$ 1,657,938	\$ 437,313	\$ 438,768	\$ 118,631	-	\$ 2,652,650

<sup>(1)</sup> 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)	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10
<b>FINANCIAL HIGHLIGHTS<sup>(1)</sup></b>					
Net Revenue <sup>(2)</sup>					
Gas	<b>77.7</b>	81.3	87.8	79.4	75.6
Power	<b>29.6</b>	23.0	33.7	27.4	23.3
Utilities	<b>16.0</b>	19.0	26.3	22.0	14.8
Corporate	<b>(5.0)</b>	(8.1)	(10.4)	2.7	(10.0)
Intersegment Elimination	<b>(0.4)</b>	(1.5)	0.3	(0.8)	(1.1)
	<b>117.9</b>	113.7	137.7	130.7	102.6
EBITDA <sup>(2)</sup>					
Gas	<b>32.8</b>	39.5	44.5	38.6	35.4
Power	<b>25.6</b>	19.6	30.7	24.3	20.8
Utilities	<b>6.0</b>	8.0	14.8	13.0	5.8
Corporate	<b>(7.9)</b>	(10.4)	(9.2)	(5.2)	(7.4)
	<b>56.5</b>	56.7	80.8	70.7	54.6
Operating Income (Loss) <sup>(2)</sup>					
Gas	<b>18.4</b>	25.2	30.2	23.7	20.9
Power	<b>21.5</b>	15.5	26.6	20.4	17.0
Utilities	<b>2.9</b>	5.0	11.8	9.6	3.0
Corporate	<b>(9.4)</b>	(11.4)	(10.1)	(6.1)	(8.3)
	<b>33.4</b>	34.3	58.5	47.6	32.6

<sup>(1)</sup> Columns may not add due to rounding.

<sup>(2)</sup> Non-GAAP financial measure.

# Supplementary Quarterly Operating Information

(unaudited)

	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10
<b>OPERATING HIGHLIGHTS [To be updated]</b>					
<b>GAS</b>					
<b>E&amp;T</b>					
Extraction inlet gas processed (Mmcfd) <sup>(1)</sup>	871	828	909	870	776
Extraction volumes (Bbls/d) <sup>(1)</sup>	39,781	38,843	42,248	39,329	37,642
Frac spread - realized (\$/Bbl) <sup>(1)(3)</sup>	22.95	36.65	32.45	27.59	24.02
Frac spread - average spot price (\$/Bbl) <sup>(1)(4)</sup>	42.15	41.27	40.91	34.74	26.86
<b>FG&amp;P</b>					
Processing Throughput (gross Mmcfd/d) <sup>(1)</sup>	404	391	375	401	425
Capacity utilization (%) <sup>(1)</sup>	34	33	32	34	36
<b>Energy Services</b>					
Average volumes transacted (GJ/d) <sup>(1)</sup>	340,396	377,917	403,777	428,669	356,981
<b>POWER</b>					
Volume of power sold (GWh) <sup>(1)</sup>	760	727	740	752	711
Average price realized on sale of power (\$/MWh) <sup>(1)(7)</sup>	80.67	64.26	78.76	64.43	61.53
Alberta Power Pool average spot price (\$/MWh) <sup>(1)</sup>	94.70	52.12	83.33	45.90	35.69
<b>UTILITIES</b>					
Natural gas deliveries - end-use (PJ) <sup>(5)</sup>	2.3	3.7	9.3	7.0	2.3
Natural gas deliveries - transportation (PJ) <sup>(5)</sup>	1.1	1.2	1.3	1.3	1.3
Service sites <sup>(2)</sup>	75,126	74,823	75,055	74,664	73,531
Degree day variance from normal - AUI (%) <sup>(6)</sup>	(33.7)	4.6	10.9	4.4	23.0
Degree day variance from normal - Heritage Gas (%) <sup>(6)</sup>	(20.9)	2.4	(3.2)	(11.0)	(48.1)

(1) Average for the period.

(2) As at period end.

(3) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from sales recorded by the business during the period on frac exposed volumes plus the settlement value of frac hedges settled in the period divided by the total frac exposed volumes produced during the period. Third quarter 2011 realized frac spread was affected by the Younger Extraction Plant turnaround and the timing of NGL sales and NGL volumes reported.

(4) 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.

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

(6) 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.

(7) 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](http://www.altagas.ca).

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