# NEWS RELEASE
# ALTAGAS REPORTS STRONG FOURTH QUARTER AND FULL YEAR RESULTS FOR 2011

**Calgary, Alberta (March 8, 2012)** – AltaGas Ltd. (AltaGas or the Corporation) (TSX:ALA; ALA.PR.A; ALA.R) today reported a 19 percent increase in normalized earnings from its operating businesses for both the full year and fourth quarter 2011 compared to the same periods in 2010. Normalized net income before taxes increased 25 percent in 2011 to $136.5 million, compared to $108.7 million in 2010.

Normalized net income for 2011 was $102.1 million ($1.21 per share) compared to $101.7 million ($1.25 per share) for 2010. Future income taxes reported in 2011 were $16.7 million ($0.20 per share) higher than 2010 as a result of recording taxes for a full year as a corporation, compared to 6 months in 2010 as a result of converting to a corporate structure from a trust structure on July 1, 2010. In fourth quarter 2011, normalized net income was $29.7 million ($0.34 per share) compared to $25.9 million ($0.31 per share) in the same quarter 2010.

Normalized EBITDA for 2011 increased 13 percent to $282.1 million, from $249.6 million in 2010. Normalized funds from operations increased 16 percent to $225.7 million for 2011 compared to $195.0 million in 2010.

Reported net income applicable to common shares for 2011 was $83.6 million ($0.99 per share) compared to $97.2 million ($1.19 per share) for 2010. In fourth quarter 2011, net income applicable to common shares was $29.9 million ($0.35 per share) compared to $26.5 million ($0.32 per share) for the same quarter 2010.

"It has been an exciting year for AltaGas. Our base business performed very well, and we continued to grow and diversify our already strong portfolio of energy infrastructure assets," said David Cornhill, Chairman and Chief Executive Officer of AltaGas. "We remain financially disciplined and we continue to grow responsibly by adding stable assets such as PNG and SEMCO, and we continued to make significant progress on our major construction projects."

In 2011 all three businesses, Gas, Power and Utilities, delivered stronger results than 2010, driven by higher volumes at extraction facilities, strong frac spreads, higher power generated from the wind and gas-fired generation portfolio, as well as the addition of Pacific Northern Gas Ltd. (PNG) in fourth quarter 2011. The increases were partially offset by the impact of two major scheduled turnarounds in the Gas division, lower volumes at some field processing facilities and transaction costs primarily related to the acquisition of PNG.

In fourth quarter 2011, Gas and Power delivered stronger earnings than fourth quarter 2010, while Utilities realized lower results. These results were driven by higher volumes at extraction facilities, strong frac spreads, higher power generated at the gas-fired and wind facilities and the addition of PNG. The increases were partially offset by the impact of a scheduled turnaround and lower throughput at some field facilities, transaction costs related to acquisitions and the impact on Utilities of warmer than normal weather.

On February 1, 2012, AltaGas announced the acquisition of SEMCO Holding Corporation (SEMCO) for US$1.135 billion including the assumption of US$355 million debt. The addition of SEMCO will add approximately $725 million in rate base. In 2013, the first full year of operations approximately two-thirds of AltaGas' cash flow is expected to come from long-term contracted or regulated assets. AltaGas will then serve more than 536,000 utility customers in Canada and the United States; closing is expected in the third quarter 2012.

On December 20, 2011, AltaGas acquired PNG, increasing rate base by over 50 percent to more than $500 million and increasing customers from 75,000 to more than 115,000. Increased natural gas exploration taking place in areas such as the Montney and Horn River areas, and increased industrial and economic activity in northern BC, are expected to result in rate base and customer growth in areas such as Dawson Creek and Fort St. John. The significant geographic alignment of PNG and other key AltaGas assets, such as the Bear Mountain Wind Park and the Younger facility, position AltaGas well to take advantage of opportunities to capitalize on the need for infrastructure in all its business segments of Gas, Power and Utilities as LNG activity materializes.

"Overall, we expect to deliver stronger results in 2012 over last year. Our operating assets are performing well, and we expect to see throughput increase in our Gas business. In our Utility business, increased earnings are expected with addition of PNG, rate base growth at Heritage and AUI, and closing the SEMCO acquisition in third quarter. With lower power prices expected in Alberta, our conventional power business is anticipated to be slightly lower," says Cornhill. "In 2012, we plan to bring on almost $1.8 billion in new assets. These additions add over $200 million in annualized EBITDA. I am very proud of what we have accomplished in 2011 as we continue to build a strong company to serve our customers and create shareholder value for the long term."

In January 2012, AltaGas expanded its renewable power generation into the United States through the acquisition of interests in two biomass power generation assets, adding 35 MW of renewable energy under long-term Power Purchase Arrangements (PPAs). AltaGas also acquired a 50 percent interest in a 29 MW wind farm in Colorado with a 25-year PPA with Black Hills/Colorado Electric Utility Company, LP. The wind farm in Colorado is expected to be in service in late 2012.

In 2011, many milestones were met for the Northwest projects. At the 195 MW Forrest Kerr Project (the Forrest Kerr Project), approximately 30 percent of underground excavation was completed including five of the seven tunnels required, and construction of the intake structure and manufacturing of the turbines began. The Forrest Kerr Project is expected to be completed and operational by July 2014 for a total cost of approximately $725 million and has a 60-year Electricity Purchase Agreement (EPA) in place with BC Hydro. As at December 31, 2011, 86 percent of the project costs have been contractually committed to fixed price contracts. AltaGas also signed Impact Benefit Agreements (IBAs) with the Tahltan First Nation and 60-year EPAs with BC Hydro in the latter part of 2011 for the McLymont Creek and Volcano Creek projects. These two projects will generate approximately 82 MW of power beginning fourth quarter 2015, and cost approximately $300 million. The Northwest projects, once completed, will generate enough power to provide electricity to 94,000 homes.

Various gas initiatives are also underway. The Gordondale and Harmattan Co-stream facilities are both underpinned by long-term contracts and are expected to commence operations in 2012. An expansion at the Blair Creek facility is expected to add approximately 50 Mmcf/d of processing capacity and be in service in second quarter 2012.

**Financial Highlights**

- Normalized EBITDA for fourth quarter 2011 was $80.3 million compared to $70.1 million for same quarter 2010. Normalized EBITDA in 2011 was $282.1 million compared to $249.6 million in 2010;
- Normalized funds from operations were $69.4 million ($0.80 per share) for fourth quarter 2011, up from $57.9 million ($0.70 per share) for same period 2010. Normalized funds from operations in 2011 were $225.7 million ($2.69 per share) compared to $195.0 million ($2.39 per share) in 2010;
- AltaGas increased its annual dividend to common shareholders by 4.5 percent to $1.38 per share to shareholders of record as at November 25, 2011;
- AltaGas declared dividends of $29.7 million in fourth quarter 2011 ($0.34 per share) and $112.2 million ($1.33 per share) in 2010;
- AltaGas completed the issuance of 4,910,500 common shares on November 15, 2011, resulting in gross proceeds of $144 million;
- The Corporation completed a $200 million issuance of senior unsecured medium term notes on October 17, 2011. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019; and
- Net debt as at December 31, 2011, was $1,320.0 million, compared to $1,049.3 million as at September 30, 2011, and $902.4 million as at December 31, 2010. AltaGas' debt-to-total capitalization ratio as at December 31, 2011 was 49.3 percent versus 46.6 percent as at September 30, 2011, and 42.7 percent as at December 31, 2010.

**Reconciliation of Normalized Results**

| ($ millions) | Three Months Ended December 31 2011 | 2010 | Year Ended December 31 2011 | 2010 |
|---|---|---|---|---|
| **Normalized EBITDA**[1] | **80.3** | 70.1 | **282.1** | 249.6 |
| Add (deduct) | | | | |
| Unrealized (loss) gain on risk management contracts | **7.2** | - | **(8.3)** | (1.3) |
| Unrealized (loss) gain on held for trading assets | **(1.0)** | 0.7 | **(9.1)** | (4.4) |
| Transaction costs before taxes | **(5.7)** | - | **(5.7)** | - |
| **EBITDA**[1] | **80.8** | 70.8 | **259.0** | 243.9 |
| | | | | |
| **Normalized Net Income**[1] | **29.7** | 25.9 | **102.1** | 101.7 |
| Add (deduct) | | | | |
| Unrealized (loss) gain on risk management contracts | **5.4** | - | **(6.2)** | (0.7) |
| Unrealized (loss) gain on held for trading assets | **(0.9)** | 0.6 | **(8.0)** | (3.8) |
| Transaction costs after taxes | **(4.3)** | - | **(4.3)** | - |
| **Net income applicable to common shares** | **29.9** | 26.5 | **83.6** | 97.2 |
| | | | | |
| **Normalized Funds from Operations**[1] | **69.4** | 57.9 | **225.7** | 195.0 |
| Add (deduct) | | | | |
| Transaction costs before taxes | **(5.7)** | - | **(5.7)** | - |
| **Funds from Operations**[1] | **63.7** | 57.9 | **220.0** | 195.0 |
| | | | | |
| ($ per share) | | | | |
| **Normalized EBITDA** [1] | **0.93** | 0.85 | **3.36** | 3.06 |
| Add (deduct) | | | | |
| Unrealized (loss) gain on risk management contracts | **0.08** | - | **(0.10)** | (0.02) |
| Unrealized (loss) gain on held for trading assets | **(0.01)** | 0.01 | **(0.11)** | (0.05) |
| Transaction costs before taxes | **(0.07)** | - | **(0.07)** | - |
| **EBITDA**[1] | **0.93** | 0.86 | **3.08** | 2.99 |
| | | | | |
| **Normalized Net Income**[1] | **0.34** | 0.31 | **1.21** | 1.25 |
| Add (deduct) | | | | |
| Unrealized (loss) gain on risk management | **0.07** | - | **(0.07)** | (0.01) |
| Unrealized (loss) gain on held for trading assets | **(0.01)** | 0.01 | **(0.10)** | (0.05) |
| Transaction costs after taxes | **(0.05)** | - | **(0.05)** | - |
| **Net Income applicable to common shares** | **0.35** | 0.32 | **0.99** | 1.19 |
| | | | | |
| **Normalized Funds from Operations**[1] | **0.80** | 0.70 | **2.69** | 2.39 |
| Add (deduct) | | | | |
| Transaction costs before taxes | **(0.07)** | - | **(0.07)** | - |
| **Funds from Operations**[1] | **0.73** | 0.70 | **2.62** | 2.39 |
| | | | | |
| Shares outstanding | **86.6** | 82.2 | **84.0** | 81.5 |
| Shares outstanding- diluted | **89.2** | 82.5 | **85.2** | 81.9 |

[1]Non-GAAP financial measures

**Monthly Common Share Dividend and Quarterly Preferred Share Dividend**

- AltaGas announced the March common share dividend of $0.115 for each share will be paid on April 16, 2012, to holders of record on March 26, 2012. The ex-dividend date is March 22, 2012. This dividend is an eligible dividend for Canadian income tax purposes; and
- AltaGas' Board also approved a preferred share dividend of $0.3125 per Series A Preferred Share for the period commencing January 1, 2012, and ending March 31, 2012. The dividend will be paid on March 30, 2012, to Series A Preferred Shareholders of record on March 16, 2012.

**CONFERENCE CALL AND WEBCAST DETAILS:**

AltaGas will hold a conference call today, March 8, 2012, at 9:00 a.m. MT (11:00 a.m. ET) to discuss the fourth quarter and full year 2011 financial and operating results and other general issues and developments.

Members of the investment community, media and other interested parties may dial (416) 340-2218 or call toll free at 1-866-226-1793. No pass code is required. A live audio webcast will also be available at http://www.altagas.ca/investors/presentations_and_events or http://www.gowebcasting.com/3019

Shortly after the conclusion of the call, a replay will be accessible at (905) 694-9451 or 1-800-408-3053. The pass code is 8005241. The webcast will be archived for one year and will expire at midnight (ET) on March 15, 2013.

## FORWARD-LOOKING INFORMATION

*The audited consolidated annual financial statements and annual Management's Discussion and Analysis (MD&A), which contained additional notes and disclosures, are expected to be filed with SEDAR on or about March 12, 2012, at which time a press release to that effect will be issued. The material will also be available on the AltaGas website on that same day (www.altagas.ca).*

*This news release contains forward-looking statements. When used in this news release 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 news release 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"; "Utility 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 news release, 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 news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this news release herein should not be unduly relied upon. These statements speak only as of the date of this news release. 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 news release are expressly qualified as cautionary statements.*

*Financial outlook information contained in this news release 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 news release should not be used for the purposes other than for which it is disclosed herein.*

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

**CONSOLIDATED FINANCIAL REVIEW**

The fourth quarter press release 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.

**Three Months Ended December 31**

In fourth quarter 2011, normalized operating income from the operating businesses was $63.9 million or 19 percent higher than $53.7 million in same quarter 2010. Gas and Power delivered stronger earnings than fourth quarter 2010 while Utilities realized lower results. These results were driven by higher volumes at extraction facilities, strong frac spreads, higher power generated at the gas-fired and wind facilities and the addition of PNG. The increases were partially offset by the impact of a scheduled turnaround and lower throughput at some field facilities, transaction costs related to acquisitions and the impact on Utilities of warmer than normal weather.

In fourth quarter 2011, normalized net income was $29.7 million ($0.34 per share) compared to $25.9 million ($0.31 per share) in the same quarter 2010. In fourth quarter 2011, AltaGas reported after-tax unrealized mark-to-market gains on risk management contracts and held-for-trading assets of $4.5 million, compared to mark-to-market gains of $0.6 million in fourth quarter 2010.

The fourth quarter was impacted by the planned turnaround at the Harmattan Complex (Harmattan), which reduced operating income by approximately $6 million. During the turnaround at Harmattan, AltaGas completed tie-in work required for the Co-stream and Cogeneration II Projects, expected to be in service in second quarter 2012.

Net income applicable to common shares for fourth quarter 2011 was $29.9 million ($0.35 per share), compared to $26.5 million ($0.32 per share) for same period 2010.

The Gas segment reported higher operating income during the fourth quarter 2011 compared to same period in 2010 primarily due to higher realized frac spreads, higher extraction fees from increased volumes, higher fees earned from the addition and expansion of gas processing facilities and lower operating expenses offset by the Harmattan turnaround, lower daily contract quantity at the Suffield system, higher variable operating costs with higher extraction volumes and increased administration costs associated with the Gas division’s growth.

The Power segment reported higher operating income in fourth quarter 2011 compared to same quarter 2010 due to higher realized power prices, the addition of the Harmattan cogeneration facility, higher generation from gas-fired peaking plants and stronger results from Bear Mountain Wind Park (Bear Mountain), partially offset by higher Power Purchase Arrangement (PPA) costs, higher variable operating costs, higher general and administration costs associated with the recent growth activities, transaction costs and higher amortization with the addition of the Harmattan cogeneration facility.

The Utility segment reported lower operating income in fourth quarter 2011 compared to same quarter 2010, mainly due to transaction costs related to the acquisition of Pacific Northern Gas Ltd. (PNG), higher depletion at Ikhil and warmer weather at the Alberta and Nova Scotia utilities. These differences were partially offset by rate base growth at AltaGas Utilities Inc. (AUI) and Heritage Gas and the operating results for PNG. During the last 11 days of 2011, PNG contributed $1.3 million to AltaGas' operating income.

The Corporate segment reported a higher loss in fourth quarter 2011 compared to the same quarter last year due to higher interest expense, partially offset by mark-to-market gains.

On a cash flow basis, normalized funds from operations in fourth quarter 2011 were $69.4 million ($0.80 per share) compared to $57.9 million ($0.70 per share) in fourth quarter 2010. Normalized EBITDA in fourth quarter 2011 was $80.3 million compared to $70.1 million in fourth quarter 2010. In fourth quarter 2011, AltaGas declared dividends to common shareholders of approximately 43 percent of normalized 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 was paid on December 15, 2011 to common shareholders of record at close of business on November 25, 2011.

On a consolidated basis, net revenue for fourth quarter 2011 was $157.4 million compared to $130.8 million in same period 2010. The Gas reporting segment's net revenue increased largely due to higher realized frac exposed volumes and higher frac spreads, higher fee-for-service revenues earned by extraction facilities, higher recoveries of operating costs and contributions from new and expanded gas processing facilities. These increases were partially offset by the impact of the Harmattan turnaround and lower daily contract quantity on the Suffield system. Net revenue in the Power segment increased due to higher spot Alberta power prices, higher generation from gas-fired peaking plants, and higher results from Bear Mountain. Increases were partially offset by higher hedging losses, higher PPA 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 the addition of PNG, higher recoverable costs and rate base growth at AUI and Heritage Gas. The Corporate segment recorded higher net revenue due to unrealized gains on risk management contracts partially offset by mark-to-market losses on an equity investment compared to mark-to-market gains in same period 2010.

Operating and administrative expense for fourth quarter 2011 was $76.5 million, up from $60.1 million in fourth quarter 2010. The increase was primarily due to higher operating costs at extraction facilities due to the Harmattan turnaround and higher volumes processed partially offset by lower operating costs related to the field gas processing facilities due to lower volumes processed and lower general and administrative costs. In the Power segment, the operating costs increased as a result of the addition of the Harmattan gas-fired cogeneration facility, higher variable costs at the peaking facilities and Bear Mountain, higher administrative costs and acquisition costs. The Utility segment incurred higher recoverable operating and administrative costs at both AUI and Heritage Gas along with the addition of PNG, including related acquisition costs. Operating expenses in Corporate segment were similar in the fourth quarter 2011 compared to the same period in 2010.

Amortization expense for fourth quarter 2011 was $24.3 million compared to $22.4 million in same period 2010. The increase was due to the addition of new and expanded facilities. Accretion expense for fourth quarter 2011 was $0.6 million compared to $0.7 million for same period 2010.

Interest expense in fourth quarter 2011 was $13.3 million compared to $12.1 million for same period 2010. The increase was due to a higher average debt balance of $1,180.1 million (2010 - $900.8 million) partially offset by a lower average borrowing rate of 6.0 percent (2010 - 6.1 percent).

Capitalized interest in fourth quarter 2011 was $4.4 million compared to $1.9 million in same period 2010.

In fourth quarter 2011, an income tax expense of $9.6 million was reported compared to an income tax expense of $6.2 million in fourth quarter 2010.

**Full Year 2011**

In 2011, AltaGas delivered stronger results from its operating businesses compared to 2010. Normalized operating income reported by the three business segments was higher at $221.0 million; a 19 percent increase over $185.0 million in 2010. The results reflect the higher natural gas volumes processed at extraction facility, field gathering processing higher liquids-rich gas, higher frac spreads, higher power generated and higher rate base at the utilities. The increases were partially offset by the scheduled turnarounds at Harmattan and Younger as well as lower daily contract quantities on the Suffield pipeline and lower volumes at some field facilities as a result of the impact of low natural gas prices in areas producing dry gas.

Normalized net income for 2011 was $102.1 million ($1.21 per share) compared to $101.7 million ($1.25 per share) for 2010. Net income applicable to common shares for 2011 was $83.6 million ($0.99 per share) compared to $97.2 million ($1.19 per share) in 2010. In 2011, AltaGas reported future income taxes of $18.6 million, based on a full year as a corporation, compared to $1.9 million in 2010, based on being a corporation for six months. Normalized net income before taxes in 2011 was 25 percent higher at $136.5 million compared to $108.7 million in 2010. In 2011, AltaGas reported transaction costs primarily related to the acquisition of PNG of $4.3 million (after tax).

In 2011, AltaGas reported a pre-tax unrealized loss on risk management contracts of $8.3 million compared to a pre-tax loss of $1.3 million in 2010. In 2011, the Corporation also reported a pre-tax mark-to-market loss related to an equity investment of $9.1 million, compared to a pre-tax mark-to-market loss of $4.4 million in 2010.

On a cash flow basis, normalized funds from operations was $225.7 million ($2.69 per share) in 2011 compared to $195.0 million ($2.39 per share) in 2010. Normalized EBITDA in 2011 was $282.1 million compared to $249.6 million in 2010. For the year ended December 31, 2011, AltaGas declared dividends to common shareholders of approximately 50 percent of normalized funds from operations.

The Gas segment reported higher operating income of $104.9 million in 2011, compared to $86.9 million in 2010. Results in the Gas business were stronger despite the $12 million impact of two major scheduled turnarounds in 2011. Increased earnings were due to higher realized frac spreads, higher frac exposed volumes, sale of the Groundbirch facility, higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities, lower amortization, lower administration costs as a result of cost cutting measures, settlement of a take-or-pay contract, increased revenues from gas services provided 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 major turnarounds, lower daily contract quantity on the Suffield system, increased variable operating costs associated with more extraction volumes and lower margins realized in the natural gas storage business.

The Power segment reported operating income for 2011 of $86.0 million, a 15 percent increase, compared to $74.7 million in 2010. Operating income increased as a result of higher realized power prices, higher generation from the Harmattan cogeneration facility, higher run time of the gas-fired peaking plants, and higher generation from Bear Mountain. These increases were offset by higher PPA costs, higher general and administrative expenses, amortization resulting from the recent growth and transaction costs related to the acquisition of power assets in the U.S.

The Utility segment reported higher operating income of $24.4 million in 2011 compared to $23.4 million in 2010. The increase was mainly due to growth in rate base of 13 percent and 23 percent at AUI and Heritage Gas, respectively, and the addition of the PNG assets, partially offset by transaction costs related to the acquisition of PNG, higher depletion rate related to the Ikhil assets and higher unrecoverable operating and corporate expense.

The Corporate segment reported a higher loss of $40.5 million in 2011 compared to $31.8 million in 2010. The increase was due to the mark-to-market loss related to an equity investment in a publicly traded company. Adjusting for the impact of mark-to-market accounting, the Corporate segment reported an operating loss of $31.3 million compared to $27.4 million in 2010.

On a consolidated basis, net revenue for 2011, was $526.7 million compared to $485.5 million in 2010. The Gas segment reported higher net revenue compared to the prior year due to higher frac exposed volumes, higher frac spreads, 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 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 environmental compliance costs and higher transmission costs. The Utilities reported higher net revenue mainly due to growth in rate base, including the addition of PNG, and higher recoverable costs at AUI and Heritage Gas. The Corporate segment recorded lower net revenue due to lower realized investment income, higher mark-to-market losses on risk management contracts and an equity investment.

Operating and administrative expense for 2011 was $267.7 million, up from $241.5 million in 2010. The increase was primarily due to incremental costs at extraction facilities from higher volumes processed and expenses incurred during turnarounds, transaction costs primarily related to the acquisition of PNG, partially offset by lower general and administrative expenses.

Amortization expense for 2011 was $90.1 million compared to $89.2 million in 2010. Accretion expense for 2011 was $2.4 million compared to $2.9 million in 2010.

Interest expense for 2011 was $52.7 million compared to $48.8 million in 2010. The increase was due to a higher average borrowing rate of 6.2 percent (2010 - 5.4 percent) and a higher average debt balances of $1,032.6 million (2010 - $988.0 million).

Capitalized interest for 2011 was $11.0 million compared to $4.4 million in 2010.

In 2011, an income tax expense of $18.8 million was reported compared to an income tax expense of $1.7 million in 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 its future taxes 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 reflected the substantively enacted tax rates anticipated to be in effect in the periods in which the differences are expected to reverse.

**GROWTH CAPITAL**

Based on projects currently under review, development or construction and the cash to close the pending acquisition of SEMCO, AltaGas expects capital expenditure for 2012 to be approximately $1.5 billion allocated approximately 20 percent for Gas, 25 percent for Power and 55 percent for Utilities.

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. On closing of the SEMCO acquisition and upon satisfaction of certain escrow release conditions, the 13,915,000 subscription receipts issued on February 22, 2012, will be converted to 13,915,000 common shares of AltaGas for gross proceeds of approximately $403 million. As at December 31, 2011, the Corporation had $848.3 million of available credit facilities. On March 2, 2012, AltaGas closed a new US$300 million credit facility which expires March 2, 2013, and extended the term of its $600 million and $75 million credit facilities to May 30, 2016.

**SEMCO Acquisition**

On February 1, 2012, AltaGas announced the acquisition of SEMCO Holding Corporation (SEMCO) for US$1.135 billion including US$355 million in assumed debt. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR and a 65 percent interest in a regulated natural gas storage utility in Alaska under construction called CINGSA. SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in an unregulated natural gas storage facility in Michigan. The acquisition of SEMCO is expected to close in third quarter 2012.

**Forrest Kerr Hydroelectric Project**

Construction of the 195 MW Forrest Kerr run-of-river power generation project (Forrest Kerr Project) is progressing well. The project includes approximately 4,879 major linear meters of tunneling. Excavation of the tunnels has advanced as expected due to a stable and consistent rock formation. As at December 31, 2011, a total of 2,270 linear meters have been excavated and approximately 86 percent of the project costs have been contractually committed to fixed price contracts.

Five of seven tunnels were completed and excavation of the power tunnel and power house began. In 2011, manufacturing of the turbines began and work progressed on the desander, intake structure and the 37 km transmission line to the Bob Quinn station. The Forrest Kerr Project is expected to be completed and operational by July 2014 for a total cost of approximately $725 million. AltaGas has a 60-year Electricity Purchase Agreement (EPA) with BC Hydro which is fully indexed to Consumer Price Index (CPI).

**McLymont Creek and Volcano Creek Hydroelectric Projects**

AltaGas signed 60-year inflation indexed EPAs with BC Hydro and Impact Benefit Agreements with the Tahltan First Nation for its 66 MW McLymont Creek and 16 MW Volcano Creek run-of-river power generation projects. Subject to environmental assessment and permitting, construction is expected to begin in the latter half of 2012 and 2013 for McLymont Creek and Volcano Creek, respectively. Combined the two projects are estimated to cost approximately $300 million and are scheduled to be in service in late 2015.

**Harmattan Co-stream**

The Harmattan Co-stream Project (the Co-stream Project) will use 250 Mmcf/d of existing spare capacity to recover ethane and other NGL from natural gas sourced from the NOVA Gas Transmission Ltd. (NGTL) Western System. The project costs are expected to be slightly over the budgeted costs of $130 million plus 20 percent contingency and is expected to commence operations in second quarter 2012. Costs have increased as a result of higher engineering costs, rock formations along the pipeline route, increased equipment costs and in-plant construction costs. The project timeline is delayed slightly due to an additional National Energy Board ("NEB") process that was not anticipated. The NEB approval to connect the AltaGas pipeline to the TransCanada pipeline has been obtained. AltaGas has experienced the impact of labour and engineering shortages but has managed to mitigate some of those increases by employing smaller, local contractors. Management will continue to look for ways of managing the rising costs of construction in Alberta. Based on current capital cost estimates, AltaGas expects the annual EBITDA contribution to be slightly over $25 million.

AltaGas had $146 million of committed capital costs by the end of 2011. Pipeline construction was 95 percent complete by year-end and plant construction is proceeding as planned with the first phase of construction successfully completed before year-end. As at December 31, 2011, 70 percent of expected costs were incurred.

On March 4, 2011, AltaGas entered into a definitive agreement with NOVA Chemicals Corporation (NOVA Chemicals) for the project. The agreement is for an initial term of 20 years whereby AltaGas will deliver all natural gas liquids extracted from co-stream gas on a full cost-of-service basis to NOVA Chemicals. The agreement provides that all capital expenditures and operating costs related to the project will be fully recovered through fees under normal operations.

In early January 2011, two of initial interveners in AltaGas' Energy Resources Conservation Board (ERCB) application filed notices of motion for leave to appeal the ERCB decision to approve the 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 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, and the hearing date has been set for April 5, 2012. AltaGas continues to believe that the grounds set forth by the intervening parties for appeal are without merit. AltaGas remains committed to the construction schedule as outlined above. One of the parties applied to the ERCB for a stay of the ERCB decision approving the Co-stream Project, which was rejected by the ERCB on September 9, 2011.

**Gordondale Gas Plant**

In 2011, construction proceeded on AltaGas' 120 Mmcf/d Gordondale Gas Processing Facility (Gordondale Gas Plant) in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The plant will be equipped with liquids extraction facilities. The facility is supported by a long-term gathering and processing agreement with a major natural gas producer to supply natural gas to the facility. AltaGas expects the annual EBITDA contribution to be $30 million to $35 million. The facility and associated gas gathering system is expected to cost approximately $236 million and be in service late 2012. The project is experiencing cost pressures primarily related to the shortage of labour and engineering expertise. Management continues to manage construction to mitigate rising costs, for example by moving to shop manufacturing of modules that require less field labour for on-site construction. Management will continue to look for ways of managing the rising costs of construction in Alberta.

AltaGas had approximately $180 million of committed capital costs by the end of 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 II**

In 2011 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 II Project (the Cogeneration II Project) is estimated to cost $24 million and be in service during second quarter 2012.

$20 million of costs have been committed for this project. The application to the Alberta Utilities Commission (AUC) was approved in fourth quarter 2011, as was the Alberta Environment application license.

**Busch Ranch Project**

AltaGas has acquired a 50 percent interest in a wind farm project with Black Hills in southern Colorado. Black Hills received approval from the Colorado Public Utilities Commission to construct a 29 MW wind farm in Huerfano County, just south of Pueblo, Colorado. The project is planned for completion in late 2012 and has a 25-year PPA.

Under the arrangement, AltaGas has no construction risk. The wind farm has abundant wind resources and is in close proximity to an existing transmission system that serves the 94,000 customers of Black Hills in southern Colorado.

**Blair Creek**

The approximate $42 million expansion of the Blair Creek Gas Plant began construction in late 2011. The expansion will increase production capacity by 50 Mmcf/d and raise the licensed capacity to 82 Mmcf/d. The expansion is expected to be completed in second quarter 2012. The expansion is contractually supported by three active producers in the area.

## RESULTS OF OPERATIONS BY REPORTING SEGMENT

| **Operating Income** | Three Months Ended December 31 | | Year Ended December 31 | |
|---|---|---|---|---|
| ($ millions) | **2011** | 2010 | **2011** | 2010 |
| Gas | **31.0** | 23.7 | **104.9** | 86.9 |
| Power | **22.4** | 20.4 | **86.0** | 74.7 |
| Utility | **4.8** | 9.6 | **24.4** | 23.4 |
| Sub-total: Operating Businesses | **58.2** | 53.7 | **215.3** | 185.0 |
| Corporate | **(9.6)** | (6.1) | **(40.5)** | (31.8) |
| | **48.6** | 47.6 | **174.8** | 153.2 |

**GAS**

| **OPERATING STATISTICS** | Three Months Ended December 31 | | Year Ended December 31 | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| **E&T** | | | | |
| Extraction inlet gas processed (Mmcf/d)(1) | **923** | 870 | **883** | 798 |
| Extraction ethane volumes (Bbls/d)(1) | **27,642** | 25,792 | **26,565** | 25,453 |
| Extraction NGL volumes (Bbls/d)(1) | **15,812** | 13,537 | **14,513** | 12,654 |
| Total extraction volumes (Bbls/d)(1) | **43,453** | 39,329 | **41,078** | 38,107 |
| Frac spread - realized ($/Bbl)(1) (2) | **42.00** | 27.59 | **33.67** | 27.27 |
| Frac spread - average spot price ($/Bbl)(1) (3) | **46.59** | 34.74 | **42.88** | 31.95 |
| **FG&P** | | | | |
| Processing throughput (gross Mmcf/d)(1) | **391** | 401 | **391** | 423 |
| Capacity utilization (%)(4) | **33** | 34 | **33** | 35 |
| **Energy Services** | | | | |
| Average volumes transacted (GJ/d)(5) | **357,105** | 428,669 | **369,603** | 386,004 |

*(1) Average for the period.*

*(2) 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.*

*(3) Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from the average sales price at AltaGas' facilities received for propane, butane and condensate and the daily AECO natural gas price.*

*(4) As at the end of the reporting period.*

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

In 2011, average ethane and NGL volumes in the extraction business increased by 1,112 Bbls/d and 1,859 Bbls/d, respectively compared to 2010. Volumes were higher at most extraction facilities as a result of higher inlet volumes, successful contracting efforts for Empress extraction facilities, commencement of the Septimus Pipeline in December 2011, partially offset by the Harmattan and Younger turnarounds.

In 2011, throughput in FG&P averaged 391 Mmcf/d compared to 423 Mmcf/d in 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 70 Mmcf/d from natural declines or well shut-ins during 2011 compared to the same period in 2010. These reductions were offset by increased production at certain FG&P facilities that saw higher throughput on average of 39 Mmcf/d over the prior year. This equates to an annual average replacement factor, (the ratio of higher volumes at certain facilities compared to facilities recording lower volumes) of more than 50 percent during 2011 compared to 33 percent in 2010.

During fourth quarter 2011, the FG&P business scheduled several outages to allow for new tie-ins and commencement of expanded facilities. Excluding the impact of these outages, current quarter gas processing volumes averaged 405 Mmcf/d compared to the reported average of 391 Mmcf/d (fourth quarter 2010 – 401 Mmcf/d). During fourth quarter 2011, throughput at certain gas processing facilities grew by approximately 54 Mmcf/d, which partially offset declines of approximately 63 Mmcf/d from other facilities, when compared to the reported volumes in fourth quarter 2010. This resulted in approximately 85 percent of the current quarter's declines being offset by the addition of new volumes, also known as the replacement factor (fourth quarter 2010 – 52 percent). The estimated replacement factor for each of the previous quarters in 2011 compared to each of the same quarters in 2010 was as follows: 19 percent for first quarter, 47 percent for second quarter and 72 percent for third quarter. Based on these metrics, the field gas processing business has been able to demonstrate increased capabilities to attract new volumes each quarter to partially offset declines experienced at other facilities, especially in a low natural gas price environment.

**Three Months Ended December 31**

The Gas segment recorded operating income of $31.0 million in fourth quarter 2011, compared to $23.7 million in fourth quarter 2010. Higher operating income was primarily due to higher realized frac spreads, higher extraction fees from increased volumes, higher fees earned from the addition and expansion of gas processing facilities and lower amortization and operating expenses. These were offset by the Harmattan turnaround, lower daily contract quantity at the Suffield system, higher variable operating costs due to higher extraction volumes and increased administration costs associated with the gas division's growth. Field gas processing throughput during fourth quarter averaged 405 Mmcf/d, excluding planned outages, compared to the first, second and third quarter of 375 Mmcf/d, 391 Mmcf/d and 404 Mmcf/d, respectively.

The fourth quarter was impacted by the planned turnaround at Harmattan, which reduced operating income by approximately $6 million. During the turnaround at Harmattan, AltaGas completed tie in work required for the Co-stream and Cogeneration II Projects that will come on line in 2012. Excluding the impact of the turnaround, fourth quarter operating income was $37.0 million or 56 percent higher than the fourth quarter 2010.

Net revenue in the Gas segment for fourth quarter 2011 was $92.8 million compared to $79.4 million for same period 2010. Net revenue increased largely due to higher realized frac spreads and higher frac exposed volumes, higher fee-for-service revenues earned by extraction facilities, higher recoveries of operating costs and contributions from new and expanded gas processing facilities. These increases were partially offset by the impact of the Harmattan turnaround and lower daily contract quantity on the Suffield system.

Operating and administrative expense in fourth quarter 2011 was $47.4 million compared to $40.8 million in fourth quarter 2010. Operating costs during the quarter increased due to the Harmattan turnaround and higher operating costs at extraction facilities from higher volumes. These increases were partially offset by lower operating costs at some processing plants related to lower volumes processed and cost control measures.

Amortization expense in fourth quarter 2011 was $13.8 million compared to $14.2 million in fourth quarter 2010. Accretion expense in fourth quarter 2011 was $0.6 million compared to $0.7 million in fourth quarter 2010. The decreases were due to revised estimates to some property, plant and equipment useful lives offset by growth in AltaGas' asset base.

**Full Year 2011**

The Gas segment reported operating income of $104.9 million for 2011, a 21 percent increase compared to $86.9 million in 2010.

The financial impact of the Younger and Harmattan scheduled major turnarounds was approximately $12 million in 2011. Operating income increased due to higher realized frac spreads, higher frac exposed volumes, sale of the Groundbirch, higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities, lower amortization, settlement of a take-or-pay contract, increased revenues from gas services provided 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, increased variable operating costs associated with more extraction volumes and lower margins realized in the natural gas storage business.

Excluding one-time items in 2011 and 2010, the Gas segment increased operating income by more than 20 percent during 2011 compared to 2010. Operating income earned from unhedged frac spreads was approximately 18 percent in 2011 compared to 20 percent in 2010 when compared to the overall operating income for the Gas segment.

Net revenue increased $22.1 million due to higher frac realized frac spreads and higher frac exposed volumes, $4.7 million from higher operating expense recoveries, $5.3 million from higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities of $1.8 million, increased contributions of $1.6 million from gas services and lower provision for doubtful accounts of $1.0 million. In addition, net revenue increased due to one-time items that included the sale of Groundbirch for a gain of $6.2 million and the settlement of a take or pay contract for $2.0 million. These increases were partially offset by lost revenue impact from the Younger and Harmattan turnarounds of $5.9 million, lower transmission revenues of $5.4 million which was driven largely by lower daily contract quantity on the Suffield system, lower volumes processed at certain gas processing facilities of $4.0 million and lower natural gas storage margins of $2.3 million.

Operating and administrative expense for 2011 was $177.4 million compared to $163.8 million in 2010. Operating costs during the period increased as a result of the Younger and Harmattan turnarounds of approximately $6 million and increased variable costs associated with more extraction volumes. These increases were partially offset by lower administration costs as a result of increased efficiencies and full-year cost saving measures implemented in 2010.

Amortization expense for 2011 was $55.0 million compared to $59.1 million in 2010. Accretion expense for 2011 was $2.4 million compared to $2.8 million in 2010. The decreases were due to revisions in estimates in the lives of certain facilities, partially offset by additional amortization expenses associated with new or expanded facilities.

**Gas Outlook**

The Gas business is expected to deliver stronger results in 2012 than in 2011. Stronger results are expected due to the completion of the Co-stream Project and Gordondale Gas Plant, as well as expansions at other field processing and extraction assets as producers look to increase netbacks from liquids-rich gas. Stronger results are also expected as a result of not having any major turnarounds in 2012, compared to two major turnarounds in 2011. 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 and lower daily contract quantity commitment on the Suffield natural gas transmission system. Other reductions for 2012 include one-time items from 2011 of approximately $8 million comprised of the gains recorded from the sale of Groundbirch facility and settlement of a take-or-pay contract.

Throughput at the extraction assets is expected to increase in 2012 over 2011 as a result of full year operation of the Septimus Pipeline, the addition of the Co-stream Project in second quarter of 2012, success in contracting new gas supply for this same facility and no major turnarounds scheduled during 2012. Drilling activity in northeast B.C. and west central Alberta has increased as producers continue the development of tight and shale gas plays within the area.

AltaGas expects higher volumes within the field processing business as a result of the completion of Gordondale in late 2012 and the expansion of Blair Creek expected to commence operations in second quarter 2012. These projects, a full year of operation of the Marlboro Gas Plant, the Henderson Pipeline, expanded gas processing capabilities at the Alder Flats Gas Plant, along with higher volumes at Bantry and Princess due to high producer activity in the area are expected to more than offset the volume declines at other facilities. Areas experiencing higher activity levels are being driven by producers focusing on high NGL content gas plays or light oil plays which create significant solution gas thereby increasing throughput at some of the field processing plants. In 2012, more than half of the throughput volumes for the field processing business are anticipated to be captured through facilities near or inside the Montney, Wilrich, Notikewin and other liquids-rich gas formations and associated gas from oil or solution gas production. Despite these encouraging developments, if natural gas prices remain at current pricing levels for most of 2012, management has estimated that average gas processing volumes would be 8 percent lower than expected, but still higher than 2011 due to the addition of Gordondale Gas Plant and other expansions mentioned above. Overall, the impact of lower natural gas processing volumes on operating income is not expected to be material based on additional revenues that would be earned from frac exposed NGL volumes which benefit from lower natural gas prices.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve, management expects spot NGL frac spread prices for AltaGas to average approximately $35/Bbl before deducting extraction premiums. In 2012, the Corporation estimates that 13 percent of total extraction volumes will be exposed to frac spread. For 2012, approximately 75 percent of the exposure has been hedged at an average price of $35/Bbl compared to 70 percent hedged at $27.78/Bbl in 2011.

## POWER

| OPERATING STATISTICS | Three Months Ended December 31 | | Year Ended December 31 | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| Volume of power sold (GWh)[(1)(2)] | **774** | 752 | **3,003** | 2,828 |
| Average price realized on the sale of power ($/MWh)[(1)(2)] | **79.14** | 64.43 | **75.94** | 66.79 |
| Alberta Power Pool average spot price ($/MWh)[(1)] | **76.13** | 45.90 | **76.22** | 50.76 |

[(1)] *Average for the period.*

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

**Three Months Ended December 31**

Operating income for fourth quarter 2011 was $22.4 million, an increase of 10 percent compared to $20.4 million for same period 2010. Operating income increased as a result of higher generation from the gas-fired cogeneration facility at Harmattan, higher run-time of the gas-fired peaking plants, higher generation from Bear Mountain offset by higher cost of generation, higher general and administrative costs, transaction costs related to acquisitions and amortization resulting from the recent growth.

In fourth quarter 2011, AltaGas was 72 percent hedged in Alberta at an average price of approximately $76/MWh. In fourth quarter 2010, AltaGas was 61 percent hedged at an average price of approximately $73/MWh.

Net revenue for fourth quarter 2011 was $33.6 million compared to $27.4 million for same period 2010. The increase was primarily due to higher spot Alberta power prices, higher generation from the Harmattan gas-fired cogeneration facility, higher generation from gas-fired peaking plants, and higher generation from Bear Mountain. The increases were partially offset by higher hedging losses, and higher PPA costs.

Operating and administrative expense was $7.1 million for fourth quarter 2011 compared to $3.1 million for same period 2010. The increase was primarily due to the addition of the Harmattan gas-fired cogeneration facility, higher variable costs at the peaking facilities and Bear Mountain, higher administrative costs and transaction costs related to recent acquisitions.

Amortization expense was $4.1 million for fourth quarter 2011 compared to $3.9 million for fourth quarter 2010. The increase was due to the addition of the Harmattan cogeneration facility.

**Full Year 2011**

Operating income for 2011 was $86.0 million, a 15 percent increase compared to $74.7 million in 2010. Overall results in power were driven by the addition of new power generating assets and higher generation from Bear Mountain. While power prices in Alberta were significantly higher in 2011 compared to 2010, the net contribution to operating income from the Sundance PPA was similar to 2010 due to the hedging strategy as well as the RAPP mechanism of the PPA which resulted in higher PPA costs. Operating income increased as a result of higher realized power prices, higher generation from the Harmattan cogeneration facility, higher run-time of the gas-fired peaking plants, higher generation from Bear Mountain offset by higher PPA costs, higher general and administrative costs and higher amortization resulting from the recent growth. For 2011, AltaGas hedged 62 percent of power sold in Alberta at an average price of $70/MWh compared to 63 percent hedged at $64.50/MWh in 2010.

Net revenue for 2011 was $120.0 million compared to $101.8 million in 2010. The increase was primarily due to higher realized power prices of $19.5 million, higher generation from the Harmattan cogeneration facility of $6.6 million, higher run-time of the gas-fired peaking plants of $6.0 million, higher generation from Bear Mountain of $6.7 million, increased number of commercial & industrial customers of $0.9 million, partially offset by higher PPA costs of $21.5 million.

Operating and administrative expense was $17.6 million for 2011 compared to $11.8 million in 2010. This increase was primarily due to the full year operation of the Harmattan cogeneration facility, higher run times of the peaking facilities, higher general and administrative costs and transaction costs associated with recent acquisitions. Amortization expense was $16.3 million for 2011 compared to $15.3 million in 2010. This increase was primarily due to the addition of the Harmattan cogeneration facility.

**Power Outlook**

The Power business is expected to report stronger earnings in 2012 from the addition of approximately 70 MWs of new power generation assets in 2012. In Canada, the addition of the second cogeneration facility at Harmattan, the gas-fired peaker at the Gordondale Gas Plant site and the waste heat recovery plant are all expected to add to earnings in 2012. The addition of approximately 35 MW of biomass power generation assets and the acquisition of the 50 percent interest in a wind farm in Colorado in the United States with long-term PPAs are also expected to increase earnings. On an annualized basis, EBITDA from these new assets is expected to be approximately $10 million. The increased earnings from new assets is expected to be more than offset by the impact of lower power prices in Alberta in 2012 compared to 2011 based on the current forward spot prices.

For first quarter 2012, AltaGas has hedged approximately 75 percent of the expected Alberta based power generation at an average price of $80 per MWh. For the second through fourth quarters of 2012, AltaGas has hedged approximately 56 percent of the expected production at an average price of $65 per MWh. On a full year basis, AltaGas is approximately 60 percent hedged at an average price of $70 per MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages.

According to AESO, if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 13,000 MW of new generation may be required over the next 20 years. Improved economic conditions in Alberta are expected to bring increased power demand to the province and provide further support to prices over the long-term.

**UTILITIES**

| **OPERATING STATISTICS** | Three Months Ended December 31 | | Year Ended December 31 | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| Natural gas deliveries - end-use (PJ)[(1)] | **6.5** | 7.0 | **21.8** | 19.9 |
| Natural gas deliveries - transportation (PJ)[(1)] | **1.1** | 1.3 | **4.6** | 5.3 |
| Service sites [(2)] | **115,932** | 74,664 | **115,932** | 74,664 |
| Degree day variance from normal - AUI (%) [(3)] | **(10.9)** | 4.4 | **-** | (1.6) |
| Degree day variance from normal - Heritage Gas (%) [(3)] | **(27.7)** | (11.0) | **(12.7)** | (13.2) |

*[(1)] Petajoule (PJ) is one million gigajoules (GJ).*

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

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

**Three Months Ended December 31**

The Utility segment reported operating income of $4.8 million for fourth quarter 2011 compared to $9.6 million for same period in 2010. Operating income decreased mainly due to transaction costs related to the acquisition of PNG, higher depletion expense at Ikhil and warmer weather at the Alberta and Nova Scotia utilities. These differences were partially offset by rate base growth at AUI and Heritage Gas Limited and the acquisition of PNG which since closing on December 20, contributed $1.3 million to operating income in the quarter.

**Full Year 2011**

Operating income for 2011 was $24.4 million compared to $23.4 million in 2010. Operating income increased due to rate base growth at AUI and Heritage Gas as well as the acquisition of PNG. The increases were partially offset by transaction costs related to the PNG acquisition, higher depletion rate related to the Ikhil assets and higher operating and corporate administrative expenses. On a combined basis, weather was not significantly different for the Utility segment in 2011 as compared to 2010.

Rate base growth of 13 percent and 23 percent at AUI and Heritage Gas, respectively, drove the 2011 results, providing an additional $4.9 million of operating income. In addition, the results for PNG during the last 11 days of the year contributed $1.3 million to 2011 operating income. These increases to operating income were partially offset by PNG's acquisition costs of $3.5 million and $2.4 million higher depletion expense at Ikhil.

Net revenue for 2011 was $86.2 million compared to $71.9 million in 2010. Net revenue increased $4.9 million from rate base growth at AUI and Heritage Gas along with $2.4 million of additional net revenue from the acquisition of PNG in late 2011. The remainder of the increased net revenue was mainly due to higher recoverable costs at the utilities.

Operating and administrative expenses for 2011 were $47.1 million compared to $36.9 million in 2010. The increases in operating costs were mainly at the regulated utilities which generally recover their costs through rates charged to their customers and the $3.5 million of acquisition costs related to the purchase of PNG. Operating costs at Ikhil were $1.0 million greater in 2011 due to repair work on one of the two gas supply wells.

Amortization expense for 2011 was $14.7 million compared to $11.6 million in 2010. The increased amortization was mainly due to $2.4 million higher depletion expense at Ikhil due to lower expected remaining reserves. The remaining increase in amortization was due to higher investment in property, plant and equipment and intangible assets.

**Utilities Outlook**

Results in 2012 are expected to be stronger than 2011, driven by rate base growth of 14 percent and 16 percent at AUI and Heritage Gas, respectively. The addition of PNG and SEMCO are also expected to result in a significant increase in earnings and cash flow from the Utility segment. The first full year of PNG is expected to add approximately $25 million in EBITDA and SEMCO upon close in third quarter is expected to add approximately $40 million in EBITDA in fourth quarter 2012. Utility results will also be impacted by the one-time charge of approximately $7.0 million of transaction costs related to the SEMCO acquisition. AltaGas expects regulated rate base at the utilities to increase from approximately $505 million in 2011 to $1.3 billion in 2012. This growth will come from the addition of $725 million of rate base through the SEMCO acquisition and approximately $70 million through organic growth within AUI, PNG, Heritage Gas as well as spending in fourth quarter at SEMCO. AltaGas expects total utility customers to increase from approximately 115,000 in 2011 to approximately 536,000 in 2012. AltaGas has a $20 million contingent payment receivable related to PNG’s 2011 sale of its interest in PTP. Receipt of the payment is contingent on the purchasers of PTP making a decision to proceed with construction of the Kitimat LNG facility.

**AUI**

AltaGas expects AUI to perform in line with expectations as filed in its 2010 to 2012 General Rate Applications (GRA). In 2012, AUI is forecast to spend approximately $29 million, growing mid-year rate base by 14 percent to approximately $174 million. For 2012, AUI’s approved regulated return on equity (ROE) is 8.75 percent on a prescribed equity of 43 percent.

AUI is operating in regulatory lag for a number of items, including all of AUI's debt recovery rates and its full 2010 to 2012 GRA including costs of service and capital programs. The 2010 and 2011 capital incurred and plan for 2012 are subject to regulatory approval which is not expected until March 2012.

AUI filed its Incentive Regulation (IR) application in July 2011 which will change the basis of AUI's regulation from a cost-of-service recovery model to an incentive based model. A hearing for AUI's IR application is scheduled for April 2012 with a decision expected in the third quarter of 2012. IR will be effective January 1, 2013, and the initial term is expected to be five years.

**PNG**

AltaGas expects PNG to perform in line with its 2012 GRA. In 2012, PNG is forecast to spend approximately $8 million on its regulated business, to grow rate base to approximately $177 million. For 2012, PNG's approved weighted average regulated ROE is 10.09 percent on a weighted average prescribed equity of 44 percent.

On November 30, 2011, PNG filed its 2012 GRA and on December 7, 2011, the BCUC approved interim rates as requested in the application. PNG is required to update the GRA by March 15, 2012 to reflect its new forecast of 2012 costs based on the December 20, 2011 acquisition by AltaGas. A decision on the application is not expected until summer 2012.

PNG has a $20 million contingent payment receivable related to PNG's 2011 sale of its interest in PTP. Receipt of the payment is contingent on the purchasers of PTP making a decision to proceed with construction of the Kitimat LNG facility.

**Heritage Gas**

AltaGas expects Heritage Gas to perform in line with the first year of its 2012 to 2014 GRA settlement. In 2012, Heritage Gas is forecast to spend approximately $26 million to continue the expansion of service to the Bedford, Dartmouth, Halifax Mainland, Halifax Peninsula - regions of the Halifax Regional Municipality along with the Amherst/Airport region with the installation of approximately 50 km of mains and the connection of 600 new customers. The revenue deficiency account (RDA), a component of rate base, is expected to decrease slightly in 2012. Through the net combination of capital expenditures and RDA changes, mid-year rate base is expected to grow by 16 percent to approximately $202 million. For 2012, Heritage Gas' approved ROE is 11 percent and the debt recovery rate is 7.25 percent on a prescribed capital structure of 45 percent equity and 55 percent debt.

**Inuvik Gas & Ikhil**

Ikhil and Inuvik Gas are evaluating short and long term strategies for maintaining gas supply and are currently taking steps to mitigate the impact of a shortage of gas supply from the currently producing well. These steps have included the decision by the Northwest Territories Power Corporation (NWTPC) to convert to 90 percent diesel for its power generation from natural gas. The conversion commenced in early 2012. Natural gas production from the second well at Ikhil currently meets the demands of Inuvik Gas, the gas supplier for the Town of Inuvik. A report on the estimated life of reserves has been finalized which indicates that as at December 31, 2011, there are approximately 1.2 to 2.3 years remaining at current and anticipated usage rates. The Ikhil Joint Venture operator, on behalf of the joint venture partners, continues to work with consultants and other parties to evaluate alternative gas supply production options for meeting future requirements.

## CORPORATE

### Three Months Ended December 31

The operating loss for fourth quarter 2011 was $9.6 million compared to $6.1 million for fourth quarter 2010. The operating loss increased primarily due to $1 million of unrealized loss compared to an unrealized gain of $0.7 million in the same quarter 2010.

Operating and administrative expense was $7.8 million in fourth quarter 2011 compared to $7.8 million in fourth quarter 2010. Amortization expense was $1 million in fourth quarter 2011 compared to $1 million in the same quarter 2010.

### Full Year 2011

### 2011 Financial Results

The operating loss for 2011 was $40.5 million compared to $31.8 million in 2010. The operating loss increased by $7.1 million due to lower investment gains realized and income received and $4.7 million higher unrealized mark-to-market losses on equity investments, partially offset by lower general and administrative costs of $4.1 million. Amortization expense was $4.1 million for 2011 compared to $3.1 million in 2010. The increase was due to an increase in Corporate assets.

Operating and administrative expense was $27.5 million for 2011 compared to $31.6 million in 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 International Financial Reporting Standards (IFRS) conversion project, conversion to a corporation and Harmonized Sales Tax (HST) compliance costs.

### Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2012 in the Corporate segment is expected to be lower than the loss reported in 2011. During 2011, AltaGas incurred one-time costs related to the planned 2012 transition to US GAAP.

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 2012 results. AltaGas does not execute financial instruments for speculative purposes.

# Consolidated Balance Sheets

(unaudited)

| *($ thousands)* | **December 31 2011** | December 31 2010 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 4,220** | $ 2,109 |
| Accounts receivable | **251,215** | 225,217 |
| Inventory | **11,332** | 13,106 |
| Restricted cash holdings from customers | **19,672** | 17,624 |
| Regulatory assets | **5,141** | 2 |
| Risk management assets | **68,404** | 41,226 |
| Prepaid expense and other current assets | **8,427** | 5,587 |
| | **368,411** | 304,871 |
| **Property, plant and equipment** | **2,540,215** | 1,976,538 |
| **Intangible assets** | **232,685** | 139,942 |
| **Goodwill** | **258,092** | 199,497 |
| **Regulatory assets** | **104,786** | 76,515 |
| **Risk management assets** | **21,642** | 22,587 |
| **Long-term investments and other assets** | **16,589** | 32,588 |
| | **$ 3,542,420** | $ 2,752,538 |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | **$ 327,143** | $ 229,618 |
| Dividends payable | **10,264** | 9,078 |
| Short-term debt | **16,824** | 9,478 |
| Current portion of long-term debt | **105,962** | 1,508 |
| Customer deposits | **25,570** | 21,432 |
| Regulatory liabilities | **503** | 1,494 |
| Risk management liabilities | **72,973** | 39,209 |
| Other current liabilities | **11,314** | 12,302 |
| | **570,553** | 324,119 |
| **Long-term debt** | **1,201,473** | 893,498 |
| **Asset retirement obligations** | **44,318** | 39,516 |
| **Future income taxes** | **272,272** | 233,763 |
| **Regulatory liabilities** | **26,686** | 18,518 |
| **Risk management liabilities** | **20,608** | 20,598 |
| **Other long-term liabilities** | **28,810** | 15 |
| **Future employee obligations** | **15,560** | 11,480 |
| | **2,180,280** | 1,541,507 |
| **Shareholders' equity** | **1,356,714** | 1,211,031 |
| **Non-controlling interest** | **5,426** | - |
| | **$ 3,542,420** | $ 2,752,538 |

# Consolidated Statements of Income

(unaudited)

| *($ thousands except per share amounts)* | Three Months Ended December 31 **2011** | 2010 | Year Ended December 31 **2011** | 2010 |
|---|---|---|---|---|
| **REVENUE** | | | | |
| Operating | **$ 416,235** | $ 359,462 | **$ 1,580,908** | $ 1,352,427 |
| Unrealized (loss) on risk management contracts | **7,177** | (25) | **(8,337)** | (1,337) |
| Other (expenses) revenue | **(760)** | 2,728 | **(8,799)** | 2,962 |
| | **422,652** | 362,165 | **1,563,772** | 1,354,052 |
| **EXPENSES** | | | | |
| Cost of sales | **265,301** | 231,334 | **1,037,098** | 868,554 |
| Operating and administrative | **76,549** | 60,082 | **267,679** | 241,540 |
| Accretion of asset retirement obligations | **612** | 719 | **2,446** | 2,880 |
| Depreciation, depletion and amortization | **24,326** | 22,420 | **90,068** | 89,180 |
| | **366,788** | 314,555 | **1,397,291** | 1,202,154 |
| **Foreign exchange loss** | **306** | 82 | **383** | 67 |
| **Interest expense** | | | | |
| Short-term debt | **1,475** | 280 | **5,836** | 1,533 |
| Long-term debt | **11,844** | 11,802 | **46,871** | 47,309 |
| **Income before income taxes** | **42,239** | 35,446 | **113,391** | 102,989 |
| **Income tax expense (recovery)** | | | | |
| Current | **(623)** | (1,163) | **175** | (222) |
| Future | **10,208** | 7,378 | **18,614** | 1,949 |
| **Net income from operations** | **32,654** | 29,231 | **94,602** | 101,262 |
| Preferred share dividends (net of tax) | **2,750** | 2,773 | **11,000** | 4,038 |
| **Net income applicable to common shares** | **$ 29,904** | $ 26,458 | **$ 83,602** | $ 97,224 |
| **Net income per share** | | | | |
| Basic | **$ 0.35** | $0.32 | **$ 0.99** | $ 1.19 |
| Diluted | **$ 0.34** | $0.32 | **$ 0.98** | $ 1.19 |
| **Weighted average number of shares outstanding** (thousands) | | | | |
| Basic | **86,576** | 82,189 | **84,042** | 81,512 |
| Diluted | **88,067** | 83,133 | **85,207** | 81,891 |

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

(unaudited)

| *($ thousands)* | Three Months Ended December 31 **2011** | 2010 | Year Ended December 31 **2011** | 2010 |
|---|---|---|---|---|
| **Net income** | **$ 32,654** | $ 29,231 | **$ 94,602** | $ 101,262 |
| **Other comprehensive (loss) income, net of tax** | | | | |
| Unrealized net (loss) on available-for-sale financial assets | **(840)** | 2,159 | **(7,350)** | (2,421) |
| Unrealized net (loss) on derivatives designated as cash flow hedges | **(522)** | (15,986) | **(2,304)** | (25,369) |
| Reclassification to net income of net gain on derivatives designated as cash flow hedges pertaining to prior periods | **160** | 10,950 | **884** | 3,813 |
| | **(1,202)** | (2,877) | **(8,770)** | (23,977) |
| **Comprehensive income** | **$ 31,452** | $ 26,354 | **$ 85,832** | $ 77,285 |
| **Accumulated other comprehensive (loss) income, beginning of period** | **$ (10,320)** | $ 125 | **$ (2,752)** | $ 21,225 |
| **Other comprehensive loss, net of tax** | **(1,202)** | (2,877) | **(8,770)** | (23,977) |
| **Accumulated other comprehensive (loss), end of period** | **$ (11,522)** | $ (2,752) | **$ (11,522)** | $ (2,752) |

# Consolidated Statements of Equity

(unaudited)

| For the years ended December 31<br>*($ thousands)* | **2011** | 2010 |
|---|---|---|
| **Common shares** | | |
| Balance, beginning of period | **$ 1,023,033** | 982,662 |
| Shares issued for cash on exercise of options | **7,181** | 4,915 |
| Shares issued under DRIP [1] | **34,681** | 32,062 |
| Shares issued on exercise of warrants | **-** | 3,394 |
| Shares issued on public offering (net of issuance costs and tax benefit) | **139,374** | - |
| Balance, end of period | **1,204,269** | 1,023,033 |
| | | |
| **Preferred shares** | | |
| Balance, beginning of period | **194,126** | - |
| Shares issued on public offering (net of issuance costs) | **-** | 194,126 |
| Balance, end of period | **194,126** | 194,126 |
| | | |
| **Contributed surplus** | | |
| Balance, beginning of period | **5,672** | 5,621 |
| Amortization of share options | **2,099** | 546 |
| Exercise of share options | **(141)** | (1,511) |
| Cancellation of share options | **(189)** | (90) |
| Other | **-** | 1,106 |
| Balance, end of period | **7,441** | 5,672 |
| | | |
| **Warrants** | | |
| Balance, beginning of period | **-** | 4,500 |
| Exercised | **-** | (4,500) |
| Balance, end of period | **-** | - |
| | | |
| **Accumulated earnings** | | |
| Balance, beginning of period | **(9,048)** | 34,849 |
| Net income | **94,602** | 101,262 |
| Distributions | **-** | (86,982) |
| Common share dividends | **(112,154)** | (54,139) |
| Preferred share dividends (net of tax) | **(11,000)** | (4,038) |
| Balance, end of period | **(37,600)** | (9,048) |
| | | |
| **Accumulated other comprehensive (loss) income** | | |
| Balance, beginning of period | **(2,752)** | 21,225 |
| Other comprehensive loss | **(8,770)** | (23,977) |
| Balance, end of period | **(11,522)** | (2,752) |
| | | |
| **Total shareholders' equity** | **1,356,714** | 1,211,031 |
| | | |
| **Non-controlling interest** | | |
| Balance, beginning of period | **-** | - |
| Additional investments | **5,426** | - |
| Balance, end of period | **5,426** | - |
| **Total equity** | **1,362,140** | 1,211,031 |

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

# Consolidated Statements of Cash Flows

(unaudited)

| *($ thousands)* | Three Months December 31 **2011** | Three Months December 31 2010 | Year Ended December 31 **2011** | Year Ended December 31 2010 |
|---|---|---|---|---|
| **Cash from operations** | | | | |
| Net income | **$ 32,654** | $ 29,231 | **$ 94,602** | $ 101,262 |
| Items not involving cash: | | | | |
| Amortization | **24,326** | 22,420 | **90,068** | 89,180 |
| Accretion of asset retirement obligations | **622** | 719 | **2,446** | 2,880 |
| Share-based compensation | **2,484** | 138 | **1,769** | 145 |
| Future income tax expense | **10,208** | 7,378 | **18,614** | 1,949 |
| Gain on sale of assets | **-** | (1,863) | **(6,172)** | (6,898) |
| Equity income | **(49)** | (72) | **(316)** | (328) |
| Unrealized (gains) losses on risk management contracts | **(7,177)** | 25 | **8,337** | 1,337 |
| Unrealized (gains) losses on held-for-trading investments | **1,036** | (239) | **9,149** | 4,807 |
| Other | **(423)** | 242 | **1,480** | 1,593 |
| Non-operating investment income | **-** | (83) | **-** | (923) |
| Asset retirement obligations settled | **(656)** | (245) | **(851)** | (518) |
| Net change in non-cash working capital | **(4,400)** | (6,192) | **(9,271)** | (838) |
| | **58,625** | 51,459 | **209,855** | 193,648 |
| **Investing activities** | | | | |
| Change in restricted cash holdings from customers | **(203)** | 4,586 | **(2,048)** | 9,604 |
| Acquisition of property, plant, and equipment | **(178,203)** | (64,598) | **(399,708)** | (156,992) |
| Disposition of property, plant, and equipment | **-** | 14 | **13,400** | 334 |
| Acquisition of intangible assets | **(9,696)** | - | **(31,672)** | (1,863) |
| Investment in regulatory assets | **(23,006)** | (1,227) | **(27,202)** | (10,335) |
| Distributions from equity investments | **95** | 96 | **698** | 384 |
| Disposition of short-term investments | **-** | 5,720 | **-** | 21,203 |
| Income from short-term investments | **-** | 83 | **-** | 924 |
| Business acquisitions | **(138,020)** | - | **(138,020)** | (22,720) |
| Acquisition of long-term investments and other assets | **-** | (401) | **-** | (5,240) |
| Disposition of long-term investments and other assets | **-** | - | **-** | 2,871 |
| | **(349,033)** | (55,727) | **(584,552)** | (161,830) |
| **Financing activities** | | | | |
| Issuance (repayment) of short-term debt | **10,942** | (14,609) | **4,125** | (5,149) |
| Net repayment of revolving long-term debt | **(34,023)** | (135,692) | **(77,171)** | (376,348) |
| Net issuance of long-term debt | **199,975** | 174,105 | **397,738** | 372,974 |
| Repayment of long-term debt | **(1,787)** | (449) | **(1,787)** | (101,733) |
| Dividends and distributions | **(33,097)** | (31,074) | **(125,869)** | (152,944) |
| Net proceeds from issuance of common shares | **149,672** | 10,520 | **179,772** | 35,781 |
| Net proceeds from issuance of preferred shares | **-** | - | **-** | 194,126 |
| | **291,682** | 2,801 | **376,808** | (33,293) |
| **Change in cash and cash equivalents** | **1,274** | (1,467) | **2,111** | (1,475) |
| **Cash and cash equivalents, beginning of period** | **2,946** | 3,576 | **2,109** | 3,584 |
| **Cash and cash equivalents, end of period** | **$ 4,220** | $ 2,109 | **$ 4,220** | $ 2,109 |

## 1. 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 of growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Corporation's four reporting segments:

| | |
|---|---|
| **Gas** | – NGL processing and extraction plants<br>– transmission pipelines to transport natural gas and NGL<br>– natural gas gathering lines and field processing facilities<br>– energy consulting and purchase and sale of natural gas and electricity<br>– natural gas storage facilities |
| **Power** | – coal-fired and gas-fired power output under power purchase arrangements and other agreements<br>– gas-fired power plants<br>– wind and run-of-river power plants<br>– sale of power to commercial and industrial users in Alberta |
| **Utilities** | – regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia<br>– production of natural gas to serve the power generation and heating needs of the town of Inuvik, Northwest Territories |
| **Corporate** | – the cost of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management contracts |

The following tables show the composition by segment:

| Three Months Ended December 31, 2011 (Unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination | Total |
|---|---|---|---|---|---|---|
| Revenue | **$ 303,597** | **$ 95,550** | **$ 47,672** | **$ (760)** | **$ (30,584)** | **$ 415,475** |
| Unrealized gains on risk management | **-** | **-** | **-** | **7,177** | **-** | **7,177** |
| Cost of sales | **(210,764)** | **(61,926)** | **(22,841)** | **-** | **30,230** | **(265,301)** |
| Operating and administrative | **(47,399)** | **(7,106)** | **(14,617)** | **(7,781)** | **354** | **(76,549)** |
| Accretion of asset retirement obligations | **(596)** | **(12)** | **(4)** | **-** | **-** | **(612)** |
| Amortization | **(13,790)** | **(4,079)** | **(5,421)** | **(1,036)** | **-** | **(24,326)** |
| Foreign exchange gain | **-** | **-** | **-** | **(306)** | **-** | **(306)** |
| Interest expense | **-** | **-** | **(2,785)** | **(10,534)** | **-** | **(13,319)** |
| Income (loss) before income taxes | **$ 31,048** | **$ 22,427** | **$ 2,004** | **$ (13,240)** | **-** | **$ 42,239** |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[(1)] | **$ 148,341** | **$ 66,592** | **$ 182,549** | **$ (879)** | **-** | **$ 396,603** |
| Intangible assets | **$ 5,780** | **$ (1,555)** | **21,607** | **2,348** | **-** | **$ 28,180** |
| Long-term investment and other assets[(1)] | **$ (1,623)** | **$ (47)** | **$ 3,802** | **(623)** | **-** | **$ 1,509** |
| Goodwill | **$ 143,726** | **-** | **$ 114,366** | **-** | **-** | **$ 258,092** |
| Segmented assets | **$ 1,895,424** | **$ 705,410** | **$ 822,154** | **$ 119,432** | **-** | **$ 3,542,420** |

| Year Ended December 31, 2011 (Unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination | Total |
|---|---|---|---|---|---|---|
| Revenue | **$ 1,183,903** | **$ 356,455** | **$ 165,607** | **$ (8,799)** | **$ (125,057)** | **$ 1,572,109** |
| Unrealized (losses) on risk management | **-** | **-** | **-** | **(8,337)** | **-** | **(8,337)** |
| Cost of sales | **(844,324)** | **(236,501)** | **(79,441)** | **-** | **123,168** | **(1,037,098)** |
| Operating and administrative | **(177,357)** | **(17,602)** | **(47,120)** | **(27,489)** | **1,889** | **(267,679)** |
| Accretion of asset retirement obligations | **(2,384)** | **(48)** | **(14)** | **-** | **-** | **(2,446)** |
| Amortization | **(54,982)** | **(16,289)** | **(14,626)** | **(4,171)** | **-** | **(90,068)** |
| Foreign exchange loss | **-** | **-** | **-** | **(383)** | **-** | **(383)** |
| Interest expense | **-** | **-** | **(11,499)** | **(41,208)** | **-** | **(52,707)** |
| Income (loss) before income taxes | **$ 104,856** | **$ 86,015** | **$ 12,907** | **$ (90,387)** | **-** | **$ 113,391** |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[(1)] | **$ 253,471** | **$ 151,084** | **$ 213,389** | **$ 810** | **-** | **$ 618,754** |
| Intangible assets | **$ 2,759** | **$ 85,122** | **21,607** | **2,348** | **-** | **$ 111,836** |
| Long-term investment and other assets[(1)] | **$ (20,669)** | **$ 2,791** | **$ 3,466** | **$ (1,587)** | **-** | **$ (15,999)** |
| Goodwill | **$ 143,726** | **-** | **$ 114,366** | **-** | **-** | **$ 258,092** |
| Segmented assets | **$ 1,895,424** | **$ 705,410** | **$ 822,154** | **$ 119,432** | **-** | **$ 3,542,420** |

*(1) Net additions to property, plant and equipment and long-term investments and other assets may not agree to other financial statements due to classification of acquisition (note 3)*

| Three Months Ended<br>December 31, 2010<br>(Unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 279,863 | $ 66,689 | $ 46,114 | $ 2,729 | $ (33,205) | $ 362,190 |
| Unrealized (losses) on risk management | - | - | - | (25) | - | (25) |
| Cost of sales | (200,427) | (39,293) | (24,065) | - | 32,451 | (231,334) |
| Operating and administrative | (40,810) | (3,117) | (9,058) | (7,849) | 753 | (60,081) |
| Accretion of asset retirement obligations | (710) | (9) | (1) | - | - | (720) |
| Amortization | (14,180) | (3,868) | (3,399) | (974) | - | (22,420) |
| Foreign exchange (loss) | - | - | - | (82) | - | (82) |
| Interest expense | - | - | (2,540) | (9,542) | - | (12,082) |
| Income (loss) before income taxes | $ 23,736 | $ 20,402 | $ 7,051 | $ (15,743) | - | $ 35,446 |
| Net additions to: | | | | | | |
| Property, plant and equipment[1] | $ 32,917 | $ 26,855 | $ 19,407 | $ 1,914 | - | $ 81,093 |
| Intangible assets | $ - | $ - | - | - | - | $ - |
| Long-term investment and other assets[1] | $ - | $ (23) | $ - | $ 6,757 | - | $ 6,734 |
| Goodwill | $ 143,726 | - | $ 55,771 | - | - | $ 199,497 |
| Segmented assets | $ 1,712,141 | $ 466,341 | $ 475,968 | $ 97,242 | - | $ 2,751,692 |

*(1) Net additions to property, plant and equipment and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions (note 3).*

| Year Ended<br>December 31, 2010<br>(Unaudited) | Gas | Power | Utilities | Corporate | Intersegment Elimination | Total |
|---|---|---|---|---|---|---|
| Revenue | $ 1,064,297 | $ 261,563 | $ 151,697 | $ 2,962 | $ (125,130) | $ 1,355,389 |
| Unrealized (losses) on risk management | - | - | - | (1,337) | - | (1,337) |
| Cost of sales | (751,647) | (159,720) | (79,768) | - | 122,581 | (868,554) |
| Operating and administrative | (163,816) | (11,763) | (36,918) | (31,593) | 2,549 | (241,540) |
| Accretion of asset retirement obligations | (2,839) | (33) | (8) | - | - | (2,880) |
| Amortization | (59,072) | (15,332) | (11,648) | (3,128) | - | (89,180) |
| Foreign exchange gain | - | - | - | (67) | - | (67) |
| Interest expense | - | - | (7,723) | (41,119) | - | (48,842) |
| Income (loss) before income taxes | $ 86,923 | $ 74,715 | $ 15,632 | $ (74,282) | - | $ 102,989 |
| Net additions to: | | | | | | |
| Property, plant and equipment[1] | $ 108,221 | $ 51,375 | $ 54,687 | $ 5,838 | - | $ 220,121 |
| Intangible assets | | | | | | |
| | - | $ 1,863 | - | - | - | $ 1,863 |
| Long-term investment and other assets[1] | - | $ (54) | $ (1,890) | $ 3,794 | - | $ 1,850 |
| Goodwill | $ 143,726 | - | $ 55,771 | - | - | $ 199,497 |
| Segmented assets | $ 1,712,141 | $ 466,341 | $ 475,968 | $ 98,088 | - | $ 2,752,538 |

*(1) Net additions to property, plant and equipment and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions (note 3).*

# Other Information

**DEFINITIONS**

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

**ABOUT ALTAGAS**

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

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