AltaGas

NEWS RELEASE
ALTAGAS REPORTS RECORD EARNINGS FOR FIRST QUARTER

Calgary, Alberta (April 26, 2012) – AltaGas Ltd. (AltaGas) (TSX: ALA) (TSX: ALA.PR.A) (TSX: ALA.R) today reported net income applicable to common shares of $41.3 million ($0.46 per share) for the three months ended March 31, 2012, compared to $26.7 million ($0.32 per share) for the same period 2011. Normalized net income applicable to common shares was $40.2 million ($0.45 per share) for the three months ended March 31, 2012, compared to $34.6 million ($0.42 per share) for the same period 2011. Normalized EBITDA for the three months ended March 31, 2012, was $92.5 million, compared to $81.8 million for the same period 2011. Normalized funds from operations were $75.5 million ($0.84 per share) for the three months ended March 31, 2012, compared to $61.5 million ($0.74 per share) for the same period 2011.

“This quarter we delivered record earnings, underscoring the stability and strength of our assets and the effectiveness of our business strategy. We reported over 12 percent higher operating income of $76.4 million from our business segments this quarter compared to $68.5 million in first quarter last year," said David Cornhill, Chairman and CEO of AltaGas. “Again, our diversified portfolio, contracting and hedging strategies and regulated assets contributed to a solid quarter. Strong volumes and continued strong frac spreads in our Gas business, higher hedged power generation at higher prices and low gas prices mitigated the impact of weaker power spot prices in Alberta. The Utility business benefited from the addition of Pacific Northern Gas, our new utility in British Columbia, as well as rate base growth in Alberta and Nova Scotia.”

AltaGas has significant capital projects underway, with several new and expanded assets being commissioned in the latter half of this year. The Harmattan Co-stream Project, which will use 250 Mmcf/d of existing spare capacity is expected to be in service early third quarter 2012. An expansion at the Blair Creek facility is expected to add approximately 50 Mmcf/d of processing capacity and commence operation in third quarter. Construction of the Gordondale gas plant, a 120 Mmcf/d deep-cut facility, is well underway and expected to be in service in late 2012. AltaGas initiated several new pipeline projects for total cost of approximately $40 million also expected to be in service in late 2012. In Power, the 70 MWs of new generation assets in 2012 include gas-fired plants in Alberta at two of its gas plant sites, waste heat recovery in British Columbia and renewable generation in the United States.

AltaGas’ most significant addition in 2012 is the pending acquisition of SEMCO Holding Corporation (SEMCO). On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including the assumption of US$355 million debt. The addition of SEMCO will add approximately US$725 million in rate base and is expected to be accretive to earnings and cash flow per share by more than 10 percent and add approximately $130 million in incremental EBITDA, in 2013, the first full year of ownership. In 2013, approximately two thirds of AltaGas' cash flow is expected to come from long-term contracted or regulated assets compared to 29 percent in 2011. Closing is subject to regulatory approval and is expected in third quarter 2012. The applications to the Michigan Public Service Commission and the Regulatory Commission of Alaska for approval of the transaction have been submitted, with hearings set for May in both proceedings.

“The year ahead will be busy, with almost $500 million in new gas assets, $90 million in new power assets, the acquisition of SEMCO and rate base growth at the Canadian utilities. These additions are expected to add over $200 million in EBITDA on an annualized basis,” said Cornhill, “we will see significant growth in our diversified energy infrastructure portfolio which is expected to deliver superior economic returns by growing cash flow and earnings to support sustainable dividend growth and continued capital investment.”

Construction at the 195 MW Forrest Kerr site is progressing ahead of schedule and on budget. Excavation of the power tunnel is underway, all other tunnels are completed and the power house excavation is 54 percent completed. In addition, significant work has been completed on the intake structure. As at March 31, 2012, 90 percent of project costs have been contractually committed. The environmental applications for the 66 MW McLymont Creek and the 16 MW Volcano Creek projects are in progress. Detailed engineering for McLymont Creek and Volcano Creek is on track to be completed prior to commencement of construction planned to start in second quarter this year. The McLymont Creek and Volcano Creek projects are expected to be in service in late 2015.

Financial Highlights(1)

Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). All prior comparative information has been restated to US GAAP.

- Earnings before interest, taxes, depreciation and amortization (EBITDA) were $92.5 million for first quarter 2012, compared to $81.8 million for same quarter 2011.
- Funds from operations were $75.5 million ($0.84 per share) for first quarter 2012, up from $61.5 million ($0.74 per share) for same quarter 2011.
- Net debt as at March 31, 2012 was $1,512.5 million, compared to $944.4 million at March 31, 2011 and $1,334.2 million at December 31, 2011. AltaGas' debt to total capitalization ratio as at March 31, 2012 was 52.3 percent, versus 43.7 percent at March 31, 2011 and 49.6 percent as at December 31, 2011.
- AltaGas closed a subscription receipts offering for 13,915,000 common shares for gross proceeds of approximately $403.0 million. The subscription receipts represent the holders' right to receive one common share of AltaGas contingent upon close of the SEMCO acquisition. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.
- AltaGas extended the term of the $600 million and $75 million credit facilities to four years to May 30, 2016.
- AltaGas closed a new US$300 million unsecured credit facility maturing on March 2, 2013.
- On April 13, 2012 AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020.

(1) Includes normalized Non-GAAP financial measures. See public disclosures available at www.altagas.ca or www.sedar.com for definitions

IN THE FIRST QUARTER, ALTAGAS:

- Announced the acquisition of SEMCO for US$1.135 billion including US$355 million in assumed debt. SEMCO owns and operates regulated natural gas utilities and natural gas storage in Alaska and Michigan.
- Acquired 35 MW of operating biomass assets and announced an agreement to acquire 14.5 MW of wind generation under construction in the United States.
- Acquired 25 MW of gas-fired peaking generation in Alberta. AltaGas previously had the rights to this capacity through a lease arrangement since 2004.
- Initiated new transmission projects that are expected to cost approximately $40 million and commence operations in late 2012.

CONFERENCE CALL AND WEBCAST DETAILS:

AltaGas will hold a conference call today at 9:00 a.m. MT (11:00 a.m. ET) to discuss first quarter 2012 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)-340-2216 or call toll free at 1-866-226-1792. No pass code is required. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_webcasts. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905)-694-9451 or 1-800-408-3053. The passcode is 6316376. The replay expires at midnight (Eastern) on May 3, 2012.

The complete first quarter report for 2012, including Management's Discussion and Analysis and unaudited financial statements, is available on www.altagas.ca in the Investors/Financial Reports section of its website.

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.

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 or the Corporation) as at and for the three months ended March 31, 2012, compared to the three months ended March 31, 2011. This MD&A dated April 26, 2012, should be read in conjunction with the accompanying unaudited interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three months ended March 31, 2011, and with the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2011. Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for and as at March 31, 2011, along with other select financial information for 2011 has been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is clearly labeled 'restated'.

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

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

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas and AltaGas Income 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.

ALTAGAS ORGANIZATION

The businesses of AltaGas Ltd. (the Corporation) are operated by the Corporation, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

CONSOLIDATED FINANCIAL REVIEW

Effective January 1, 2012, the Corporation follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for the three months ended and as at March 31, 2011, along with other select financial information for 2011 has been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is clearly labeled 'restated'.

	Three Months Ended March 31	
(unaudited)	**2012**	2011
($ millions)		(restated)
Revenue	**376.5**	384.5
Net revenue(1)	**167.4**	136.2
Normalized operating income(1)	**69.5**	61.1
Normalized EBITDA(1)	**92.5**	81.8
Net income applicable to common shares	**41.3**	26.7
Normalized net income(1)	**40.2**	34.6
Total assets	**3,696.1**	2,845.3
Total long-term liabilities	**1,918.9**	1,282.7
Net additions to property, plant and equipment	**147.5**	32.7
Dividends declared(2)	**30.9**	27.3
Cash flows		
Normalized funds from operations(1)	**75.5**	61.5

	Three Months Ended March 31	
($ per share)	**2012**	2011
		(restated)
Normalized EBITDA(1)	**1.03**	0.99
Net income - basic	**0.46**	0.32
Net income - diluted	**0.45**	0.32
Normalized net income(1)	**0.45**	0.42
Dividends declared(2)	**0.345**	0.33
Cash flows		
Normalized funds from operations(1)	**0.84**	0.74
Shares outstanding - basic (millions)		
During the period(3)	**89.5**	82.8
End of period	**89.8**	83.0

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

(2) *Dividends declared of $0.115 per common share per month commencing October 27, 2011.*

(3) *Weighted average.*

Three Months Ended March 31

Net income applicable to common shares in first quarter 2012 was $41.3 million ($0.46 per share) compared to $26.7 million ($0.32 per share) in same quarter last year. Normalized net income in first quarter 2012 was $40.2 million ($0.45 per share) compared to $34.6 million ($0.42 per share) in same quarter last year. In the quarter, net income was normalized by $2.3 million for after-tax market-to-market gains and $1.2 million for after-tax transaction costs related to acquisitions. In first quarter 2011, AltaGas reported after-tax unrealized mark-to-market losses of $7.9 million.

On a cash flow basis, normalized funds from operations for the three months ended March 31, 2012, was $75.5 million ($0.84 per share) compared to $61.5 million ($0.74 per share) in first quarter 2011. Normalized EBITDA in first quarter 2012 was $92.5 million compared to $81.8 million in same quarter 2011.

On a consolidated basis, normalized operating income for first quarter 2012 was $69.5 million compared to $61.1 million in same quarter 2011. Increase in normalized operating income was driven by higher frac exposed volumes and higher extraction fees earned from increased volumes, higher power volumes hedged at higher prices, the addition of biomass assets, lower natural gas prices at gas-fired power generating facilities and higher generation from Bear Mountain, the acquisition of Pacific Northern Gas Ltd. (PNG) and rate base growth at the Nova Scotia and Alberta utilities. Excluding approximately $8 million of non-recurring gains recorded in first quarter 2011, the increases were partially offset by lower Alberta power prices, higher general and administrative costs, warmer weather in Alberta and Nova Scotia and lower approved return on equity (ROE) at both Alberta Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas).

On a consolidated basis, net revenue for first quarter 2012 was $167.4 million compared to $136.2 million in same quarter 2011. Increase in net revenue was driven by higher frac exposed volumes and higher fees earned from increased volumes, higher power volumes hedged at higher prices, higher generation from Bear Mountain, low natural gas prices at the gas-fired power facilities, addition of new power assets, the addition of PNG, higher recoverable costs and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by non-recurring gains of approximately $8 million recorded in first quarter 2011. In addition, lower Alberta power prices and warmer weather in Alberta and Nova Scotia also impacted net revenue in first quarter 2012.

Operating and administrative expense for first quarter 2012 was $73.7 million, up from $64.2 million in first quarter 2011. The increase was primarily due to incremental costs associated with the addition of PNG and transaction costs related to acquisitions during the quarter, partially offset by lower operating costs at some facilities where natural gas volumes have been decreasing.

Amortization expense for first quarter 2012 was $22.2 compared to $20.1 million in same quarter 2011. The increase was due to the addition of new and expanded facilities including $1.8 million related to PNG. Accretion expense for first quarter 2012 was $0.8 million compared to $0.6 for same quarter 2011.

Interest expense in first quarter 2012 was $12.8 million compared to $12.9 million for same quarter 2011. Interest expense decreased due to higher capitalized interest of $6.6 million (first quarter 2011 - $1.5 million) and a lower average borrowing rate of 5.5 percent (first quarter 2011 - 6.3 percent). The decrease was partially offset by a higher average debt balance of $1,403.3 million (first quarter 2011 - $919.7 million).

In first quarter 2012, AltaGas recorded an income tax expense of $13.8 million compared to an expense of $9.3 million in first quarter 2011. Current taxes in the quarter were $3.2 million compared to $2.1 million in same quarter 2011. The increase was due to recoverable current taxes at PNG and higher earnings.

CONSOLIDATED OUTLOOK

On a consolidated basis, current assets in operation are expected to report stronger earnings in 2012 compared to 2011. Stronger earnings are expected in the Gas, Power and Utility businesses as a result of higher throughput, continued strong frac spreads, no major turnarounds in Gas, the addition of PNG and continued rate base growth at the Nova Scotia and Alberta utilities, as well as the impact of lower natural gas prices at the gas-fired power facilities. These are expected to be partially offset by the impact of lower realized power prices in Alberta, resulting in overall slightly lower earnings from the conventional power assets.

In 2012, AltaGas is expected to add approximately $1.8 billion in new and expanded assets across all business segments; $500 million in Gas and $90 million in Power, with the remainder at the Utilities. The acquisition of SEMCO Holding Corporation (SEMCO) for total consideration of US$1.135 billion is expected to close in third quarter, adding approximately US$725 million in regulated rate base and rate base growth at the Canadian utilities is expected to be approximately 1o percent in rate base growth. These new and expanded assets are expected to add over $200 million in annualized EBITDA.

AltaGas expects to see significant seasonality in its financial results due to the inherent seasonality in its Utility business. The seasonality of the Utility business results in lower second and third quarters and stronger first and fourth quarters. The Corporation also expects lower volume throughput and lower power prices historically experienced in second quarter to further impact earnings.

In the Gas business, volumes processed are expected to increase at certain gas processing and extraction facilities in service today as producers look to increase netbacks from liquids-rich gas and higher realized frac spreads based on current forward prices. Volumes are also expected to grow from the addition of new and expanded assets. Specifically, the Harmattan Co-stream project (Co-stream Project) and Blair Creek Expansion are expected to be in service in early third quarter 2012 and the Gordondale Gas Processing Plant (Gordondale) is expected to be in service in late 2012. AltaGas expects these volume increases to offset the impact of lower volumes expected in areas with low producer activity as a result of continued depressed natural gas prices.

In 2012, more than half of the throughput volumes for the field processing business are anticipated to be captured through facilities near or inside 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 approximately 10 percent lower than expected, but still higher than 2011 due to the addition of Gordondale and other volume growth 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 natural gas liquids (NGL) volumes and sale of power from gas-fired power facilities 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 range between $35/Bbl and $45/Bbl for the remainder of 2012. Management estimates that 13 percent of total extraction volumes in 2012 will be exposed to frac spread. For 2012, approximately 80 percent of the exposure has been hedged at an average price of approximately $35/Bbl.

AltaGas expects earnings from conventional power assets to be slightly lower in 2012 compared to 2011 as a result of current forward power prices in Alberta, which are lower than in 2011. This is expected to be partially offset by the addition of the cogeneration facility (Cogeneration II), the Crowsnest Pass waste-heat facility, the Gordondale peaking plant, and the recently acquired biomass facilities. The gas-fired power facilities are expected to benefit from low natural gas prices. For the second quarter 2012, AltaGas has hedged approximately 68 percent of volumes exposed to Alberta power pool price at an average price of $64/MWh and for the third and fourth quarter 2012 approximately 50 percent at an average price of $66/MWh.

AltaGas expects a stronger year from its Utility business in 2012 compared to 2011. Higher earnings are expected as a result of forecasted rate base growth at AUI and Heritage Gas, the benefit of a full year ownership of PNG, the potential for an incremental $20 million payment related to PNG's sale of its interest in the Pacific Trail Pipelines (PTP), and the SEMCO acquisition expected to close in third quarter 2012. AltaGas expects to add US$725 million of rate base through the SEMCO acquisition and grow rate base by approximately 10 percent at its Canadian utilities.

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 $403.0 million.

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. The allocation will be 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 $403.0 million. As at March 31, 2012, the Corporation had $883.5 million of available credit facilities. On April 13, 2012, AltaGas issued $200 million medium-term notes resulting in $1,083.5 million of available credit facilities on a pro forma basis.

AltaGas mitigates project cost escalation and schedule risk through its procurement and contracting strategies. The following is a summary of progress made during first quarter 2012 on projects currently under construction and advanced development, as well as the pending SEMCO acquisition:

SEMCO Acquisition
On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including US$355 million in assumed debt.

During first quarter 2012, applications for the approval of the SEMCO acquisition by the Michigan Public Service Commission and the Regulatory Commission of Alaska were filed. Regulatory hearing dates have been set in May for both Michigan and Alaska. The regulatory process is progressing as expected and 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 Project (Forrest Kerr Project) is progressing well and is ahead of schedule and on budget. The project includes approximately 440,000 cubic meters of rock to be excavated to support the tunneling and the powerhouse construction. Excavation of all tunnels except for the power tunnel is completed and power house excavation is advancing as expected, as a result of experiencing stable and consistent rock formation. The construction of the intake structure is well underway, with completion expected by late second quarter 2012. 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 the Canadian Consumer Price Index (CPI).

McLymont Creek and Volcano Creek Hydroelectric Projects
The environmental application process is ongoing for both the 66 MW McLymont Creek and the 16 MW Volcano Creek projects. Detailed engineering for McLymont Creek and Volcano Creek is on track to be completed prior to commencement of construction planned to start in second quarter 2012. Combined, the two projects are estimated to cost approximately $300 million and are scheduled to be in service in late 2015. AltaGas has 60 year EPAs with BC Hydro which are fully indexed to the Canadian CPI.

Harmattan Co-stream Project
The Co-stream Project will use 250 Mmcf/d of existing spare capacity to recover ethane and other NGLs from natural gas sourced in the NOVA Gas Transmission Ltd. (NGTL) Western System. The project is underpinned by a 20-year cost-of-service contract with NOVA Chemicals Corporation.

Management expects the project to cost approximately $170 million, including changes in scope and escalations for materials and labour. Based on underlying commercial terms, the project's return on investment continues to meet management's expectations. Pipeline construction was 98 percent complete at the end of first quarter 2012, with cleanup remaining for second quarter 2012. Plant construction is proceeding as planned with one unit commissioned and operations expected to commence early third quarter 2012. As at March 31, 2012, 86 percent of expected costs have been incurred. The project is expected to add approximately $25 million in annualized EBITDA

In early January 2011, two of the 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 was held on April 5, 2012. The Alberta Court of Appeal reserved its decision. 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.

Gordondale Gas Plant
In first quarter 2012, construction progressed on AltaGas' 120 Mmcf/d Gordondale deep cut, natural gas processing facility in the Montney resource play near the town of Gordondale, approximately 100 km northwest of Grande Prairie, Alberta. The project is underpinned by a long term contract with Encana.

AltaGas had approximately $228 million of committed capital costs by the end of first quarter 2012. In total, the project is expected to cost approximately $260 million, including escalations for materials and labour, which is within 10 percent of management's original estimate. The remaining costs to be incurred will be subject to cost and labour productivity risk. During the quarter, management directed several initiatives to mitigate cost escalation and maintain schedule. The project's estimated return on investment continues to be within management's expectations of 13 to 15 percent. The facility is expected to be in service in late 2012.

Major mechanical and electrical work commenced late in the first quarter of 2012, with approximately 70 percent of major equipment received on site by the end of the quarter.

Harmattan Cogeneration II
In first quarter 2012, construction progressed on a second 15 MW cogeneration unit at Harmattan Complex (Harmattan) to supply steam and power to the Co-stream Project. Mechanical and electrical work was underway in the quarter, and all major equipment was received on site by the end of the first quarter. Cogeneration II is expected to be in service in second quarter 2012.

Blair Creek

Upon the execution of long term contracts with three producers, AltaGas began construction of the estimated $42 million expansion of Blair Creek in late 2011. In first quarter 2012, construction progressed on the expansion which is expected to increase production capacity by 50 Mmcf/d and raise the licensed capacity to 82 Mmcf/d. The expansion is expected to commence commercial operation in early third quarter 2012.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and 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, normalized operating income, normalized EBITDA, normalized net income and normalized funds from operations throughout this document have the meanings as set out in this section.

Net revenue

		Three Months Ended March 31	
($ millions)		**2012**	2011 (restated)
Net revenue		**167.4**	136.2
Add:	Cost of sales	**209.1**	248.3
Revenue (GAAP financial measure)		**376.5**	384.5

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of natural gas affect both revenue and cost of sales.

Normalized Operating Income

		Three Months Ended March 31	
($ millions)		**2012**	2011 (restated)
Normalized operating income		**69.5**	61.1
Add (deduct):	Unrealized gain (loss) on held-for-trading	**1.7**	(2.8)
	Transaction costs	**(1.6)**	-
Operating income		**69.6**	58.3
Add (deduct):	Unrealized gain (loss) on risk management contracts	**1.2**	(6.9)
	Interest expense	**(12.8)**	(12.9)
	Foreign exchange (loss)	**(0.1)**	-
	Income tax (expense)	**(13.8)**	(9.3)
	Net income applicable to non-controlling interests	**(0.3)**	-
	Preferred share dividends	**(2.5)**	(2.5)
Net income applicable to common shares (GAAP financial measure)		**41.3**	26.7

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 dividends.

Normalized operating income represents operating income adjusted for non-operating related expenses such as transaction costs related to acquisitions and mark-to-market gains and losses related to equity investments.

Normalized EBITDA			Three Months Ended March 31
($ millions)		**2012**	2011 (restated)
Normalized EBITDA		**92.5**	81.8
Add (deduct):	Unrealized gain (loss) on held-for-trading	**1.7**	(2.8)
	Transaction costs	**(1.6)**	-
EBITDA		**92.6**	79.0
Add (deduct):	Unrealized (losses) on risk management contracts	**1.2**	(6.9)
	Depreciation, depletion and amortization	**(22.2)**	(20.1)
	Accretion of asset retirement obligations	**(0.8)**	(0.6)
	Interest expense	**(12.8)**	(12.9)
	Foreign exchange (loss) gain	**(0.1)**	-
	Income tax (expense)	**(13.8)**	(9.3)
	Net income applicable to non-controlling interests	**(0.3)**	-
	Preferred share dividends	**(2.5)**	(2.5)
Net income applicable to common shares (GAAP financial measure)		**41.3**	26.7

EBITDA is a measure of AltaGas' operating profitability without the impact of risk management contracts and prior to how business activities are financed, assets are amortized or earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, 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.

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as transaction costs related to acquisitions and mark-to-market gains and losses related to equity investments.

Normalized Net Income		Three Months Ended March 31
($ millions)	**2012**	2011 (restated)
Normalized net income	**40.2**	34.6
Add (deduct):		
Unrealized (loss) gain on risk management contracts	**0.8**	(5.5)
Unrealized (loss) gain on held for trading assets	**1.5**	(2.4)
Transaction costs after taxes	**(1.2)**	-
Net Income applicable to common shares (GAAP financial measure)	**41.3**	26.7

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related (expenses) recoveries, such as transaction costs related to acquisitions.

Normalized Funds from Operations ($ millions)		Three Months Ended March 31 **2012**	2011 (restated)
Normalized Funds from Operations		**75.5**	61.5
Add (deduct):	Transaction cost	**(1.6)**	-
Funds from operations		**73.9**	61.5
Add (deduct):	Net change in non-cash working capital	**22.2**	(29.2)
	Asset retirement obligations settled	**(0.5)**	(0.1)
Cash from operations (GAAP financial measure)		**95.6**	32.2

Normalized 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, and non-operating related expenses (recoveries) such as transaction costs related to acquisitions. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP. Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in non-cash working capital, expenditures incurred to settle asset retirement obligations and non-operating related expenses, such as transaction costs related to acquisitions.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income ($ millions)	Three Months Ended March 31 **2012**	2011 (restated)
Gas	**30.1**	30.2
Power	**26.9**	26.6
Utilities	**19.4**	11.7
Sub-total: Operating Businesses	**76.4**	68.5
Corporate[(1)]	**(6.8)**	(10.2)
	69.6	58.3

[(1)]Includes mark-to-market gain/loss on equity investments, excludes mark-to-market gains/losses on risk management contracts.

GAS

OPERATING STATISTICS	Three Months Ended March 31 2012	2011
Extraction and Transmission (E&T)		
Extraction inlet gas processed (Mmcf/d)(1)	**944**	909
Extraction ethane volumes (Bbls/d)(1)	**29,155**	27,892
Extraction NGL volumes (Bbls/d)(1)	**16,031**	14,261
Total extraction volumes (Bbls/d)(1)	**45,186**	42,153
Frac spread - realized ($/Bbl)(1) (2)	**34.11**	32.45
Frac spread - average spot price ($/Bbl)(1) (3)	**40.42**	40.91
Field Gathering and Processing (FG&P)		
Processing throughput (gross Mmcf/d)(1)	**400**	375
Energy Services		
Average volumes transacted (GJ/d)(4)	**376,071**	403,777

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

In first quarter 2012, average ethane and NGL volumes in the extraction business increased by 1,263 Bbls/d and 1,770 Bbls/d, respectively compared to same quarter 2011. Volumes were higher at most extraction facilities as a result of higher inlet volumes, and commencement of the Septimus Pipeline in December 2011. These increases were partially offset by lower volumes processed at the Edmonton Extraction Plant due to milder winter conditions in first quarter 2012.

FG&P throughput in first quarter 2012 averaged 400 Mmcf/d compared to 375 Mmcf/d in first quarter 2011 and 391 Mmcf/d in fourth quarter 2011. The addition of the Marlboro Gas Plant and expanded facilities during 2011 resulted in higher volumes, more than offsetting declines and shut-ins led by producers in response to low natural gas prices. As at March 31, 2012, management has estimated between 15 to 20 Mmcf/d of flowing natural gas wells had been shut-in that were previously processed at AltaGas' facilities.

During first quarter 2012, available volumes at certain gas processing facilities grew by approximately 69 Mmcf/d, which more than offset declines and shut-ins of approximately 44 Mmcf/d. This resulted in 156 percent of the current quarter’s declines being offset by the addition of new volumes, also known as the replacement factor (fourth quarter 2011 – 101 percent).

Three Months Ended March 31

The Gas segment recorded operating income of $30.1 million in first quarter 2012 compared to $30.2 million for same quarter 2011. Excluding approximately $8 million of one-time gains recorded from the sale of the Groundbirch facility and settlement of a take-or-pay contract in first quarter 2011, the Gas segment reported a 36 percent increase in operating income over first quarter 2011. The increase was due to higher frac exposed volumes, higher extraction fees earned from increased volumes, and higher volumes processed at some FG&P facilities. These increases were partially offset by lower volumes from some field facilities and lower transmission revenue which was driven by lower daily contract quantity on the Suffield system.

During first quarter 2012, AltaGas had NGL frac spread hedges that covered approximately 70 percent of frac exposed production at an average price of $35.61/Bbl. During first quarter 2011, NGL frac spread hedges covered approximately 70 percent of frac exposed production at an average price of $26.85/Bbl.

Net revenue in the Gas business for first quarter 2012 was $87.5 million, same as first quarter 2011. Excluding one-time gains recorded in first quarter 2011, net revenue increased in first quarter 2012 due to higher frac exposed volumes, higher extraction fees from increased volumes and contributions from new and expanded gas processing facilities. These increases were partially offset by lower processing volumes in some of the field processing facilities and lower transmission revenues.

Operating and administrative expense in first quarter 2012 was $42.9 million compared to $43.2 million in first quarter 2011. Higher operating costs at extraction facilities from higher volumes and higher administration costs associated with the growth of the division were offset by lower operating costs at certain gas processing facilities.

Amortization expense in first quarter 2012 was $13.8 million compared to $13.5 million in first quarter 2011. Accretion expense in first quarter 2012 was $0.8 million compared to $0.6 million in first quarter 2011.

Gas Outlook

The Gas business is expected to deliver stronger results for full year 2012 compared to full year 2011. However, second quarter 2012 results are expected to be lower than first quarter 2012 due to normal production outages required to commission new equipment for the Co-stream Project and Blair Creek Expansion, and planned maintenance activities at other facilities. In addition, local market prices for propane have drifted lower from first quarter highs and is expected to result in lower realized frac spreads in second quarter.

For full year 2012, stronger results are expected due to the completion of the Co-stream Project and Gordondale, as well as expansions at other field processing and extraction assets, as producers look to increase netbacks from liquids rich gas. Furthermore, the addition and expansion of transmission assets during 2012 are expected to improve results over 2011. In early 2012, management entered into a letter of intent with a major producer to construct, own and operate two pipelines, a C3+ (propane-plus) and a C5+ (condensate), both approximately 45 kilometres in length to connect the producer’s processing facilities to the Plateau system within northeast B.C. This project, along with expansions of other transmission assets are expected to cost approximately $40 million and commence operations in late 2012. Stronger results are also expected as a result of no major turnarounds in 2012, compared to two major turnarounds in 2011.

The above 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 the 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 a full year operation of the Septimus Pipeline, the addition of the Co-stream Project in early third quarter 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 is expected to commence commercial operations in early third quarter 2012. These projects, including full year contributions from facilities that were added or expanded during 2011 (Marlboro Gas Plant, Henderson Pipeline, Alder Flats Gas Plant, debottleneck at Bantry and Princess) 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 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 approximately 10 percent lower than expected, but still higher than 2011 due to the addition of Gordondale and other volume growth 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 range between $35/Bbl and $45/Bbl for the remainder of 2012. Management estimates that 13 percent of total extraction volumes in 2012 will be exposed to frac spread. For 2012, approximately 80 percent of the exposure has been hedged at an average price of approximately $35/Bbl compared to 70 percent hedged at approximately $28/Bbl in 2011.

POWER

OPERATING STATISTICS

	Three Months Ended March 31	
	2012	2011
Volume of power sold (GWh)[(1)]	**816**	740
Average price realized on the sale of power ($/MWh)[(1)]	**72.56**	78.76
Alberta Power Pool average spot price ($/MWh)[(1)]	**60.12**	83.33

(1) Average for the period.

Three Months Ended March 31

The Power segment reported operating income of $26.9 million for first quarter 2012 compared to $26.6 million for same quarter 2011. Operating income increased as a result of hedging a higher percentage of volumes exposed to Alberta power pool price, higher hedged prices, increased generation and prices received at the gas-fired peaking plants, lower natural gas prices at all gas-fired generating facilities, higher generation from Bear Mountain, and the addition of new biomass and hydro power generation facilities. These increases were partially offset by lower Alberta power pool prices, higher PPA costs and higher general and administrative costs.

In first quarter 2012, AltaGas was 72 percent hedged in Alberta at an average price of $80/MWh. In first quarter 2011, AltaGas was 57 percent hedged at an average price of $65/MWh.

Net revenue for first quarter 2012 was $34.6 million compared to $32.1 million for same quarter 2011. Net revenue increased due to higher hedged volumes, higher hedged prices, increased generation and prices received at the gas-fired peaking plants, lower natural gas prices at all gas-fired generating facilities, higher generation from Bear Mountain and the addition of new biomass and hydro power generation facilities. These increases were partially offset by lower Alberta power pool prices and higher PPA costs.

Operating and administrative expense was $5.1 million for first quarter 2012 compared to $3.0 million for same quarter 2011. The increase was primarily due to acquisition costs and higher maintenance costs at the peaking facilities and higher variable costs at Bear Mountain.

Amortization expense was $2.5 million for first quarter 2012 compared to $2.6 million for same quarter 2011.

Power Outlook

Overall the Power business is expected to report slightly lower earnings in 2012 compared to 2011. Earnings are expected to increase as a result of 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 a 50 percent interest in a wind farm in the United States with long-term PPAs is also expected to increase earnings.

The increased earnings from new assets and the effective hedging strategy is expected to partially offset the impact of lower power prices in Alberta in 2012 compared to 2011 based on the current forward spot prices. A major maintenance outage at the Sundance 3 facility has been scheduled by its operator for the middle of 2012 due to the mechanical failure of critical generator components experienced in 2010. During the outage, AltaGas receives revenue from the operator based on the 30-day RAPP. Second quarter has historically been a period of lower power prices and AltaGas expects results in second quarter 2012 to follow this trend.

For second quarter 2012, AltaGas has hedged approximately 68 percent of volumes exposed to Alberta power pool price at an average price of $64/MWh. For third and fourth quarter 2012, AltaGas has hedged approximately 50 percent at an average price of $66/MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages.

UTILITIES

OPERATING STATISTICS

	Three Months Ended March 31	
	2012	2011
Natural gas deliveries - end-use (PJ)[1]	**10.8**	9.3
Natural gas deliveries - transportation (PJ)[1]	**2.0**	1.3
Service sites [2]	**115,623**	75,055
Degree day variance from normal - AUI (%) [3]	**(11.5)**	23.6
Degree day variance from normal - Heritage Gas (%) [3]	**(8.6)**	8.0

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

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

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

REGULATORY METRICS

	Three Months Ended March 31	
	2012	2011
Approved return on equity (%)		
AUI[1]	**8.75**	9.00
PNG	**10.09**	-
Heritage Gas	**11.00**	13.00
Approved return on debt (%)		
AUI	**5.18**	5.28
PNG	**6.29**	-
Heritage Gas	**7.25**	8.75
Rate base		
AUI[2]	**174.1**	153.5
PNG[2]	**178.7**	-
Heritage Gas[3]	**186.3**	168.4

[1] General rate application decision received in third quarter 2011 adjusted approved ROE to 8.75 percent

[2] Mid-year rate base

[3] Weighted average rate base over the year

Three Months Ended March 31

The Utility business is predominantly comprised of natural gas distribution rate-regulated utilities, where financial results are based on a regulated allowed return on capital invested. Rate-regulated cost-of-service utilities such as AUI in Alberta, PNG in British Columbia 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 contribution to consolidated net income of the Corporation.

Operating income in the Utility business 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 for AUI and Heritage Gas can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. For AUI and Heritage Gas, 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. PNG has a rate stabilization adjustment mechanism approved by the British Columbia Utilities Commission (BCUC) which allows PNG to record the after tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates.

The Utility business reported operating income of $19.4 million for first quarter 2012, a 67 percent increase compared to $11.7 million for same quarter 2011. Operating income increased mainly due to the acquisition of PNG, which contributed $10.1 million to operating income in the quarter and rate base growth at AUI and Heritage Gas. These increases were partially offset by warmer weather and lower approved ROE at the Alberta and Nova Scotia utilities.

Net revenue for first quarter 2012 was $43.3 million compared to $26.1 million for the same quarter 2011. Net revenue was higher mainly due to the addition of PNG in December 2011, higher recoverable costs at the utilities and rate base growth at both AUI and Heritage Gas. These increases were partially offset by a decrease in delivered gas volumes due to 20 percent and 7 percent warmer weather experienced in Alberta and Nova Scotia respectively in first quarter 2012 when compared to same quarter 2011, and lower applied ROE in first quarter 2012 compared to first quarter 2011.

Operating and administrative expense was $18.9 million for first quarter 2012 compared to $11.4 million for same quarter 2011. The increase in operating costs was mainly due to the addition of PNG. Primarily all operating and administrative costs incurred at the utilities are recoverable through the rate setting mechanism to customers.

Amortization expense was $5.0 million in first quarter 2012 compared to $3.1 million in first quarter 2011. The increase in amortization expense was mainly due to the addition of PNG and $0.7 million higher depletion expense at Ikhil due to lower expected remaining reserves.

Utilities Outlook

Results in 2012 are expected to be stronger than 2011, driven by rate base growth of 14 percent and 12 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 business. 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. 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 US$725 million of rate base through the SEMCO acquisition and rate base growth at the Canadian utilities. In addition, Heritage Gas is expected to have approximately $11 million of work in progress by year end for CNG infrastructure which is expected to be included in rate base in early 2013. AltaGas expects total utility customers to increase to approximately 536,000 in 2012 from approximately 115,000 in 2011. In 2012, AltaGas expects to receive $20 million in relation 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

Throughout 2010 and 2011 AUI operated in regulatory lag for a number of items, including all of AUI's debt recovery rates and its full 2010 to 2012 General Rate Application (GRA) including costs of service and capital programs. On April 9, 2012 the Alberta Utilities Commission (AUC) issued a decision on AUI's 2010-2012 GRA. The decision approved AUI's applied for capital programs for 2010, 2011 and 2012, along with revenue requirements for 2010 and 2011 which were $3.1 million and $3.9 million lower than recognized by AUI. The main reason for the lower revenue requirements was lower approved depreciation and cost of removals, neither of which affect earnings in the period along with lower than applied for interest rates on AUI's debt. The net effect of the 2010–2012 GRA decision is expected to decrease AltaGas' 2012 earnings by approximately $0.2 million.

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. The hearing for AUI's IR application commenced on April 16, 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

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 filed an update to the GRA on March 15, 2012, to reflect its new forecast of 2012 costs based on its acquisition by AltaGas. A decision on the application is expected in third quarter 2012.

Heritage Gas

Heritage Gas is currently in the first year of an NSUARB approved three-year test period. In 2012 Heritage Gas is required to file new cost-of-service and rate design studies for the years 2013 and 2014 to update the allocation of costs amongst Heritage Gas' customers.

In 2012, Heritage Gas is forecasting to spend approximately $31 million to continue the expansion of service to the regions of the Halifax Regional Municipality along with the Amherst/Airport region. The 2012 capital expenditures will also include approximately $11 million, with an additional $3 million in 2013, for Heritage Gas to develop and construct a compressed natural gas (CNG) trucking network in Nova Scotia. To date, Heritage Gas has signed a Memorandum of Agreements (MOA) with two major customers and expects to begin service to these customers in early 2013. On April 2, 2012 Heritage Gas filed a franchise extension application with the Nova Scotia Utility and Review Board (NSUARB) related to CNG. CNG trucking will enable Heritage Gas to expand its gas distribution business and access customers which would otherwise be uneconomical.

Inuvik Gas & Ikhil

The Ikhil Joint Venture operator, along with the other joint venture partners, continues to work with the town of Inuvik, the Northwest Territories Government and other parties to evaluate alternative gas supply options for meeting future energy requirements.

CORPORATE

Three Months Ended March 31

The operating loss for first quarter 2012 was $6.8 million compared to $10.2 million for first quarter 2011. The decreased loss was due to $1.7 million of unrealized pre-tax gain on equity investments in first quarter 2012 compared to an unrealized pre-tax loss of $2.8 million in same quarter 2011. This was partially offset by higher general and administrative costs primarily due to transaction costs of $1.3 million related to the SEMCO acquisition.

Net revenue was $3.0 million in first quarter 2012 compared to net revenue in a deficit position of $9.9 million in same quarter in 2011. The increase was primarily due to changes in unrealized pre-tax gain versus loss on risk management contracts of $8.1 million, as well as an unrealized gain of $1.7 million on an equity investment compared to an unrealized loss of $2.8 million in same quarter last year.

Operating and administrative expense was $7.8 million in first quarter 2012 compared to $6.2 million in first quarter 2011. The increase in general and administrative expense is primarily due to professional fees of $1.3 million related to the acquisition of SEMCO.

Amortization expense was $0.9 million in first quarter 2012, same as first quarter 2011.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2012 in the Corporate segment is expected to be higher than the loss reported in 2011 primarily due to $7.5 million of transaction costs related to the acquisition of SEMCO and higher general and administrative costs related to the Corporation's growth, partially offset by lower costs in 2012 compared to 2011 related to the 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.

INVESTED CAPITAL

During first quarter 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $201.6 million compared to $55.3 million in first quarter 2011. The net invested capital was $187.8 in first quarter 2012 compared to $27.0 in same quarter 2011.

Invested Capital - Investment Type — **Three Months Ended March 31, 2012**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**84.2**	**72.0**	**5.0**	**0.1**	**161.3**
Intangible assets	**0.9**	**-**	**0.1**	**-**	**1.0**
Long-term investments and other assets	**(0.1)**	**36.0**	**0.1**	**3.3**	**39.3**
	85.0	**108.0**	**5.2**	**3.4**	**201.6**
Disposals:					
Property, plant and equipment	**-**	**(13.8)**	**-**	**-**	**(13.8)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**85.0**	**94.2**	**5.2**	**3.4**	**187.8**

Invested Capital - Investment Type					Three Months Ended March 31, 2011
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	25.0	29.2	4.7	1.8	60.7
Intangible assets	0.7	-	-	-	0.7
Long-term investments and other assets	0.6	(0.2)	-	(6.5)	(6.1)
	26.3	29.0	4.7	(4.7)	55.3
Disposals:					
Property, plant and equipment	(28.0)	-	-	-	(28.0)
Long-term investments and other assets	-	-	-	(0.3)	(0.3)
Net Invested capital	(1.7)	29.0	4.7	(5.0)	27.0

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

Growth capital expenditures of $200.0 million (first quarter 2011 - $53.5 million) was reported in first quarter 2012. In the Gas business, growth capital comprised $28.1 million for construction of the Co-stream Project, $36.1 million for construction of Gordondale, $11.3 million for the Blair Creek expansion, and $8.0 million for various Gas related projects. Within the Power business, growth capital projects included $49.1 million for the Forrest Kerr Project, $34.7 million for the business acquisition of Decker Energy International Inc. (DEI), $12.1 million buyout of Maxim capital lease, $3.4 million for the Harmattan Cogeneration projects, $3.3 million for the Crowsnest Pass project, $5.4 for various renewable power development projects. The Utility business saw growth capital of $5.2 million. Corporate segment reported an increase in capital of $3.3 million related to the increase in fair value of AltaGas' investment in Alterra.

Maintenance and administrative capital expenditures in 2012 were $1.1 million and $0.5 million, respectively (2011 $0.9 million and $0.9 million, respectively).

Invested Capital - Use					**Three Months Ended March 31, 2012**
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Maintenance	**1.1**	**-**	**-**	**-**	**1.1**
Growth	**83.5**	**108.0**	**5.2**	**3.3**	**200.0**
Administrative	**0.4**	**-**	**-**	**0.1**	**0.5**
Invested capital	**85.0**	**108.0**	**5.2**	**3.4**	**201.6**

Invested Capital - Use					Three Months Ended March 31, 2011
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	0.9	-	-	-	0.9
Growth	25.1	29.0	4.7	(5.3)	53.5
Administrative	0.3	-	-	0.6	0.9
Invested capital	26.3	29.0	4.7	(4.7)	55.3

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 first quarter 2012, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 8:

- Commodity forward contracts: The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services division transacts primarily on this basis. PNG has historically hedged exposures to fluctuations in natural gas prices through the use of derivative financial instruments, in accordance with its annual gas contracting and gas supply price risk management plan. PNG has not entered into any new hedging arrangements since February 2011 and the existing hedges will expire by October 2012. These estimated fair market values have no impact on earnings due to the regulated nature of PNG's operations. Based on the current regulatory process, unrealized gains or losses arising from PNG related financial instruments are treated as part of the cost of gas and are recovered from its customers.
- Commodity swap contracts:

    Power hedges: AltaGas executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power business results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $10.89/MWh to $999.99/MWh in first quarter 2012 and $6.57/MWh to $999.99/MWh in first quarter 2011. The average Alberta spot price was $60.12/MWh in first quarter 2012 (first quarter 2011 - $83.33/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 $72.56/MWh in first quarter 2012 (first quarter 2011 - $78.76/MWh). For the second quarter, AltaGas has hedged approximately 68 percent of its expected Alberta based power sales at an average price of $64/MWh. For the third and fourth quarters of 2012, AltaGas has hedged approximately 50 percent at average prices of $66/MWh.

    NGL frac spread hedges: The Corporation executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During first quarter 2012, the Corporation had NGL frac spread hedges for an average of 4,475 Bbls/d at an average price of $35.61/Bbl. The average indicative spot NGL frac spread for first quarter 2012 was approximately $40/Bbl (first quarter 2011 – approximately $41/Bbl). The average NGL frac spread realized by AltaGas in first quarter 2012 was $34.11/Bbl (first quarter 2011 - $32.45/Bbl). The Corporation has hedged an average of 4,475 Bbls/d, or approximately 80 percent of volumes that are exposed to spot prices for the remainder of 2012, at an average price of $35/Bbl. For 2013, AltaGas has hedged approximately one-third of its volumes that are exposed to frac spread at an average price of $35/Bbl.
- Interest rate forward contracts: From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. At March 31, 2012, the Corporation had no interest rate swaps outstanding. At March 31, 2012, the Corporation had fixed the interest rate on 75 percent of its debt including medium-term notes (MTNs) (December 2011 - 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 April 13, 2012, AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020.

On March 2, 2012, 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 with a new maturity date of May 30, 2016.

On March 2, 2012, AltaGas amended and extended its $75 million extendible revolving term credit facility with two Canadian chartered banks. The credit facility's term was extended with a new maturity date of May 30, 2016.

On March 2, 2012, AltaGas closed a new US$300 million unsecured credit facility maturing on March 2, 2013.

On December 20, 2011, in connection with the PNG acquisition, AltaGas assumed a $25 million bank operating facility which is available for working capital purposes and expires on May 28, 2012.

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.

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

Cash Flows		Three Months Ended March 31
($ millions)	**2012**	2011 (restated)
Cash from operations	**95.6**	32.2
Investing activities	**(243.9)**	(44.6)
Financing activities	**146.6**	121.2
Change in cash	**(1.7)**	108.8

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $95.6 million in first quarter 2012 compared to $32.2 million in first quarter 2011. The increase in cash from operations was primarily a result of higher income before taxes, offset by lower distributions from equity investments and lower non-cash working capital.

Working Capital		Three Months Ended March 31
($ millions except current ratio)	**2012**	2011 (restated)
Current assets	**321.5**	377.4
Current liabilities	**388.8**	346.0
Working capital	**(67.3)**	31.4
Current ratio	**0.83**	1.09

Working capital was in a deficit position of $67.3 million as at March 31, 2012, compared to a surplus position of $31.4 million as at March 31, 2011. The working capital ratio was 0.83 at the end of first quarter 2012 compared to 1.09 at the end of same quarter 2011. The working capital ratio decreased due to an increase in accounts payable, and a decrease in cash balance. This was partially offset by a decrease in current portion of long-term debt and an increase in accounts receivable.

Investing Activities

Cash used for investing activities in first quarter 2012 was $243.9 million compared to $44.7 million in first quarter 2011. Investing activities in first quarter 2012 primarily comprised of $202.9 million property, plant and equipment expenditures, $34.7 of business acquisition and $3.0 million of long-term investment acquisitions, compared to $46.1 million of property, plant and equipment expenditures in first quarter 2011.

Financing Activities

Cash received from financing activities was $146.6 million in first quarter 2012 compared to $121.2 million in first quarter 2011. Financing activities in first quarter 2012 primarily comprised the issuance of $279.8 million of bankers acceptances and repayment of $100.0 million MTNs compared to the issuance of $200.0 million of MTNs and repayments of $59.5 million in first quarter 2011. Dividends paid in first quarter 2012 were $33.3 million and net proceeds from issuance of common shares were $14.2 compared to $29.8 million and $11.6 million, respectively, in first quarter 2011.

CAPITAL RESOURCES

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. As at March 31, 2012, AltaGas had total debt outstanding of $1,513.7 million, up from $1,337.1 million at December 31, 2011. As at March 31, 2012, AltaGas had $1,075 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 $1,431 million. As at March 31, 2012, AltaGas had drawn bank debt of $352.1 million and letters of credit outstanding of $195.4 million against the syndicated credit facilities, the extendible revolving letter of credit facility, the bilateral letter of credit facility, the term revolver, and the demand from operating facilities. As at March 31, 2012, the Corporation had $883.5 million in available credit facilities and $1.2 million in cash and cash equivalents. On April 13, 2012, AltaGas issued $200 million of senior unsecured MTNs which was used to reduce outstanding indebtedness under its credit facilities. The Corporation has approximately $1,083.5 million in available credit facilities on a pro forma basis subsequent to the MTN issuance as at April 13, 2012.

On December 7, 2011, a new base shelf prospectus was filed with a limit of $2 billion and valid for 25 months. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance.

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

The US$1.135 billion acquisition of SEMCO expected to close in third quarter 2012 includes approximately US$355 million in assumed debt. The transaction will be funded through the net proceeds of the subscription receipts offering, together with funds to be advanced pursuant to some combination of the existing credit facilities, the new credit facility, and the proceeds of future debt and preferred share financings, as determined by AltaGas.

On February 22, 2012, AltaGas closed approximately $403.0 million in gross proceeds held in trust in connection with a subscription receipts offering for total consideration of 13,915,000 common shares. The subscription receipts offering represents the holder's right to receive one common share of the issuer contingent upon acquisition close. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.

As at March 31, 2012, AltaGas' current portion of long-term debt was $7.0 million.

AltaGas' earnings interest coverage for the rolling three months ended March 31, 2012 was 2.33 times.

Credit facilities ($ millions)	Borrowing capacity	**Drawn at March 31 2012**	Drawn at December 31 2011
Demand operating facilities	71.0	**6.0**	3.4
Extendible revolving letter of credit facility	75.0	**64.7**	67.7
PNG operating facility	25.0	**14.3**	13.9
PNG term revolver	35.0	**20.0**	20.0
Bilateral letter of credit facility	125.0	**124.3**	124.3
AltaGas Ltd. revolving credit facility (1)	600.0	**154.0**	8.0
Utility Group revolving credit facility (2)	200.0	**164.2**	30.4
USD credit facility (3)	300.0	**-**	-
	1,431.0	**547.5**	267.7

(1) Revolving credit facility maturing May 30, 2016.

(2) Revolving credit facility maturing November 17, 2015.

(3) USD unsecured credit facility maturing March 2, 2013 (assumed at par).

As at March 31, 2012, AltaGas held in aggregate $71.0 million (December 31, 2011 - $71.0 million) in demand operating and demand letter of credit facilities. As at March 31, 2012, AltaGas had draws and letters of credit of $6.0 million (December 31, 2011 - $3.4 million) outstanding against these demand facilities.

As at March 31, 2012, AltaGas held a $75.0 million (December 31, 2011 - $75.0 million) unsecured four-year extendible revolving letter of credit facility with two Canadian chartered banks maturing on May 30, 2016. AltaGas may also borrow by way of prime loans, US 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 March 31, 2012, AltaGas had letters of credit of $64.7 million (December 31, 2011 - $67.7 million) outstanding against the extendible revolving letter of credit facility.

As at March 31, 2012, AltaGas held a $25.0 million bank operating facility which is available for PNG's working capital purposes and expires on May 28, 2012. The operating facility was acquired through the acquisition of PNG. Draws and letters of credit outstanding at March 31, 2012 were $14.3 million (December 31, 2011 - $13.9 million).

As at March 31, 2012, AltaGas held a $35.0 million term revolver which was acquired through the acquisition of PNG. Draws outstanding at March 31, 2012 were $20.0 million (December 31, 2011 - $20.0 million).

As at March 31, 2012, AltaGas held a $125.0 million unsecured bilateral letter of credit facility. Borrowings on the facility bear fees and interest rates relevant to the nature of the draws made. At March 31, 2012, AltaGas had $124.3 million (December 31, 2011 - $124.3 million) letters of credit outstanding under the bilateral facility.

AltaGas has a $600 million, four-year revolving credit facility maturing on May 30, 2016. Borrowings on the facility can be by way of prime loans, US base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At March 31, 2012, AltaGas had $154.0 million (December 31, 2011 - $8.0 million) of debt outstanding under the syndicated facility.

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, US base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At March 31, 2012, AltaGas had $164.2 million (December 31, 2011 - $30.4 million) of debt outstanding under the facility.

AltaGas has a US$300 million, unsecured credit facility maturing on March 2, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptance equivalent loans. At March 31, 2012, AltaGas had $Nil outstanding under the facility.

RELATED PARTIES

AltaGas and one of its managers agreed on a loan in the principal amount of $750 thousand, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015 (first quarter 2011 - $750 thousand).

During first quarter 2012, AltaGas paid rent under a lease for office space and equipment to 2013761 Ontario Inc., which is partially owned by a former employee of AltaGas. Payments of $8 thousand were made in first quarter 2012 (first quarter 2011 - $23 thousand).

SHARE INFORMATION

At March 31, 2012, AltaGas had 89.8 million common shares and 8.0 million series A preferred shares outstanding with a combined market capitalization of $3 billion based on a closing trading price on March 31, 2012, of $30.95 per common share and $25.80 per series A preferred share. As at March 31, 2012, there were 5.3 million options outstanding and 2.3 million options exercisable under the terms of the share option plan.

DIVIDENDS

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

On 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 following table summarizes AltaGas' dividend declaration:

Dividends Years ended December 31 ($ per common share)	**2012**	2011
First quarter	**0.345**	0.330
Second quarter	**-**	0.330
Third quarter	**-**	0.330
Fourth quarter	**-**	0.340
Total	**0.345**	1.330

Preferred Share Dividends Years ended December 31 ($ per preferred share)	**2012**	2011
First quarter	**0.3125**	0.3125
Second quarter	**-**	0.3125
Third quarter	**-**	0.3125
Fourth quarter	**-**	0.3125
Total	**0.3125**	1.2500

SUBSEQUENT EVENT

On April 13, 2012, AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020. 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) was to replace Canadian Generally Accepted Accounting Principles (Canadian GAAP) for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

On September 10, 2010, the 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. The Canadian Securities Administrators provide for a similar one-year deferral pursuant to National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards (NI 52-107).

As per AcSB Decision Summary March 2012, the AcSB announced the deferral extension of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by one year to January 1, 2013, in light of recent discussions of the IASB’s future agenda. The AcSB expects to issue the amendment to the Introduction to Part 1 of the Handbook in May 2012.

AltaGas is a qualified entity for the deferral period permitted by AcSB and NI 52-107. AltaGas has elected to use the deferral offered by the AcSB and NI 52-107, given the uncertainty with respect to the application of IFRS to the RRA. AltaGas 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.

Pursuant to NI 52-107, US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

SIGNIFICANT ACCOUNTING POLICIES

Except as otherwise disclosed, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP financial statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

CRITICAL ACCOUNTING ESTIMATES

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

AltaGas' critical accounting estimates continue to be 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' 2011 Financial Report and the notes to the interim Consolidated Financial Statements for the three months ended March 31, 2012.

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 US GAAP.

During first quarter 2012, 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(1)

($ millions)	**Q1-12**	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10
Total revenue	**376.5**	399.8	339.2	322.8	384.5	362.2	297.4	334.0
Net revenue(2)	**167.4**	156.9	116.5	107.2	136.1	130.8	102.6	124.8
Operating income(2)	**69.6**	49.2	33.5	34.2	58.3	47.6	32.6	35.6
Net income before taxes	**57.8**	44.6	18.0	11.8	38.5	35.4	10.3	26.3
Net income applicable to common shares(3)	**41.3**	31.7	11.1	13.3	26.7	26.5	6.0	28.4

($ per share)	**Q1-12**	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10
Net income applicable to common shares								
Basic(3)	**0.46**	0.38	0.13	0.16	0.32	0.32	0.07	0.35
Diluted(3)	**0.45**	0.37	0.13	0.16	0.32	0.32	0.07	0.35
Distributions / dividends declared	**0.345**	0.34	0.33	0.33	0.33	0.33	0.33	0.54

(1) *Restated to comply with US GAAP from Q1-11.*

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

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

Significant items that impacted individual quarterly earnings were as follows:

- 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 Harmattan;
- In first quarter 2011, AltaGas accepted an offer from a producer to sell the Groundbirch facility, resulting in a pre-tax gain of approximately $6 million;
- 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;
- 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 between tax and book values are expected to reverse. This resulted in a decrease of future tax liabilities of $6.8 million;
- In the third and fourth quarters 2011, turnarounds at Harmattan and Younger reduced revenue and increased operating expenses resulting in lower operating income of approximately $12 million before taxes. These turnarounds have occurred every three years; and
- In fourth quarter 2011, AltaGas acquired all the outstanding common shares of PNG for $224 million including assumed debt of approximately $86 million. In the quarter, AltaGas recorded $5.7 million in pre-tax transaction costs primarily related to the acquisition of PNG and other business development related activities.

Consolidated Balance Sheets

(unaudited)

($ thousands)	March 31 2012	December 31 2011 (restated)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 1,187**	$ 2,875
Accounts receivable	**219,143**	239,210
Inventory	**11,172**	12,467
Restricted cash holdings from customers	**26,009**	19,672
Regulatory assets	**2,768**	5,141
Risk management assets *(note 8)*	**54,002**	68,404
Prepaid expense and other current assets	**7,169**	8,642
	321,450	356,411
Property, plant and equipment	**2,622,638**	2,486,050
Intangible assets	**176,770**	177,516
Goodwill *(note 4)*	**281,123**	281,123
Regulatory assets	**120,009**	120,594
Risk management assets *(note 8)*	**22,455**	21,642
Long-term investments and other assets	**28,766**	25,408
Investments accounted for by equity method	**122,911**	87,144
	$ 3,696,122	$ 3,555,888
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 6)*	**$ 252,191**	$ 314,085
Dividends payable	**10,324**	10,264
Short-term debt	**17,539**	16,824
Current portion of long-term debt *(note 5)*	**7,005**	105,962
Customer deposits	**31,750**	25,570
Regulatory liabilities	**2,768**	503
Risk management liabilities *(note 8)*	**61,171**	72,973
Other current liabilities *(note 6)*	**6,067**	11,325
	388,815	557,506
Long-term debt *(note 5)*	**1,489,178**	1,214,298
Asset retirement obligations	**44,756**	44,318
Deferred income taxes	**269,238**	265,782
Regulatory liabilities	**26,665**	26,686
Risk management liabilities	**22,052**	20,608
Other long-term liabilities	**28,800**	28,810
Future employee obligations	**38,188**	37,041
	2,307,692	2,195,049
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 89.82 million issued and outstanding *(note 9)*	**1,218,444**	1,204,269
Preferred shares cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 9)*	**194,126**	194,126
Contributed surplus	**8,006**	7,441
Accumulated other comprehensive loss	**(12,857)**	(12,297)
Accumulated deficit	**(27,756)**	(38,126)
	1,379,963	1,355,413
Non-controlling interests	**8,467**	5,426
	$ 3,696,122	$ 3,555,888

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(unaudited)

($ thousands except per share amounts)	March 31 2012	Three Months Ended March 31 2011 (restated)
REVENUE		
Operating	**$ 361,400**	$ 368,372
Unrealized gain (loss) on risk management contracts *(note 8)*	**1,157**	(6,910)
Other (expenses) revenue	**1,813**	(3,101)
Income from equity investments	**12,145**	26,119
	376,515	384,480
EXPENSES		
Cost of sales	**209,057**	248,256
Operating and administrative	**73,729**	64,170
Accretion of asset retirement obligations	**815**	608
Depreciation, depletion and amortization	**22,190**	20,053
	305,791	333,087
Foreign exchange loss (gain)	**134**	(38)
Interest expense		
Short-term debt	**457**	177
Long-term debt	**12,304**	12,727
Income before income taxes	**57,829**	38,527
Income tax expense		
Current	**3,164**	2,118
Deferred	**10,596**	7,197
Net income after taxes	**44,069**	29,212
Net income applicable to non-controlling interests	**299**	-
Net income applicable to the controlling interests	**43,770**	29,212
Preferred share dividends	**2,500**	2,500
Net income applicable to common shares	**$ 41,270**	$ 26,712
Net income per common share (note 10)		
Basic	**$ 0.46**	$ 0.32
Diluted	**$ 0.45**	$ 0.32
Weighted average number of common shares outstanding (note 10)		
($ thousands)		
Basic	**89,491**	82,753
Diluted	**90,865**	84,618

See accompanying notes to the Consolidated Financial Statements.

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

(unaudited)

		Three Months Ended
	March 31	March 31
	2012	2011
($ thousands)		(restated)
Net income after taxes	**$ 44,069**	$ 29,212
Other comprehensive (loss) income, net of tax		
Unrealized income (loss) on available-for-sale financial assets (net of tax of ($0.20) million and $0.33 million)	**1,400**	(2,166)
Unrealized income (loss) on derivatives designated as cash flow hedges (net of tax of $0.2 million and ($0.1) million)	**(556)**	257
Reclassification to net income of net gain on derivatives designated as cash flow hedges	**165**	153
Net loss arising during the period from pension and post-retirement benefit plans (net of tax of $ 0.1 million)	**(1,569)**	-
	(560)	(1,756)
Comprehensive income	**$ 43,509**	$ 27,456
Accumulated other comprehensive (loss) income, beginning of period	**$ (12,297)**	$ (5,632)
Other comprehensive income (loss), net of tax	**(560)**	(1,756)
Accumulated other comprehensive (loss), end of period	**$ (12,857)**	$ (7,388)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(unaudited)

($ thousands)		Three Months Ended **March 31 2012**	March 31 2011 (restated)
Common shares *(note 9)*			
Balance, beginning of period	**$**	**1,204,269**	1,023,033
Shares issued for cash on exercise of options		**5,727**	1,801
Shares issued under DRIP [(1)]		**8,448**	9,839
Balance, end of period		**1,218,444**	1,034,673
Preferred shares *(note 9)*		**194,126**	194,126
Contributed surplus			
Balance, beginning of period		**7,440**	5,672
Amortization of share options		**849**	425
Exercise of share options		**(209)**	(507)
Cancellation (forfeitures) of share options		**(74)**	(48)
Balance, end of period		**8,006**	5,542
Accumulated deficit *(note 9)*			
Balance, beginning of period		**(38,126)**	(8,739)
Net income applicable to the controlling interests		**43,770**	29,212
Common share dividends		**(30,900)**	(27,329)
Preferred share dividends		**(2,500)**	(2,500)
Balance, end of period		**(27,756)**	(9,356)
Accumulated other comprehensive income (loss)			
Balance, beginning of period		**(12,297)**	(5,632)
Other comprehensive (loss) income		**(560)**	(1,756)
Balance, end of period		**(12,857)**	(7,388)
Total shareholders' equity		**1,379,963**	1,217,597
Non-controlling interests			
Balance, beginning of period		**5,426**	-
Net income applicable to non-controlling interests		**299**	-
Redemption of non-controlling interests		**(5,197)**	-
Business acquisitions *(note 3)*		**7,939**	-
Balance, end of period		**8,467**	-
Total equity		**1,388,430**	1,217,597

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

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(unaudited)

($ thousands)	Three Months Ended March 31 2012	March 31 2011 (restated)
Cash from operations		
Net income after taxes	**$ 44,069**	$ 29,212
Items not involving cash:		
Depreciation, depletion and amortization	**22,190**	20,053
Accretion of asset retirement obligations	**815**	608
Share-based compensation	**565**	(131)
Future income tax expense	**10,596**	7,197
Gain on sale of assets	**-**	(6,172)
Income from equity investments	**(12,145)**	(26,119)
Unrealized (gains) losses on risk management contracts	**(1,157)**	6,910
Unrealized (gains) losses on held-for-trading investments	**(1,726)**	2,762
Other	**2,679**	978
Asset retirement obligations settled	**(449)**	(134)
Distributions from equity investments	**8,221**	26,298
Contributions to equity investments	**(167)**	-
Net change in non-cash working capital *(note 12)*	**22,151**	(29,230)
	95,642	32,232
Investing activities		
Change in restricted cash holdings from customers	**(6,337)**	1,749
Acquisition of property, plant, and equipment	**(202,891)**	(46,111)
Acquisition of intangible assets	**-**	(1,452)
Investment in regulatory assets	**3,004**	1,150
Acquisition of long-term investments	**(3,000)**	-
Business acquisitions, net of cash acquired	**(34,705)**	-
	(243,929)	(44,664)
Financing activities		
Issuance (repayment) of short-term debt	**715**	(8,637)
Net issuance (repayment) of revolving long-term debt	**167,345**	(50,856)
Net issuance of long-term debt	**541**	199,108
Repayment of long-term debt	**(2,838)**	(220)
Dividends	**(33,340)**	(29,829)
Net proceeds from issuance of common shares	**14,176**	11,641
	146,599	121,207
Change in cash and cash equivalents	**(1,688)**	108,775
Cash and cash equivalents, beginning of period	**2,875**	1,023
Cash and cash equivalents, end of period	**$ 1,187**	$ 109,798

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

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

1. ORGANIZATION AND OVERVIEW OF BUSINESS

On July 1, 2010 AltaGas Ltd. (AltaGas or the Corporation) completed its conversion from an income trust to a corporation pursuant to a plan of arrangement (the Arrangement) under the Canadian Business Corporations Act. The material businesses of AltaGas Ltd. are operated by the Corporation, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

AltaGas is a diversified energy infrastructure business with focus on natural gas, power and regulated utilities. AltaGas has three operating businesses, Gas, Power and Utilities. AltaGas' Gas business serves producers in the Western Canada Sedimentary Basic (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing. The Gas business include expansions at several gas processing facilities within liquids-rich development areas as well as construction of the Harmattan Co-stream (Co-stream Project) and the Gordondale Gas Processing Facility (Gordondale). The Power business includes 555 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. AltaGas owns 50 percent of the Sundance B Power Purchase Arrangements (PPAs), giving it the rights to power output and ancillary services from coal fired base load generation until December 31, 2020. Further generation is in various stages of construction and development including the Northwest run-of-river projects (Northwest Projects), which consist of the Forrest Kerr run-of-river project (Forrest Kerr Project), currently under construction, to come online in 2014 followed by McLymont Creek and Volcano Creek run-of-river projects (McLymont and Volcano Projects), in advanced stages of development, expected to come online in late 2015. The 277 MWs Northwest Projects are contracted with 60-year fully inflation indexed Energy Purchase Arrangements (EPAs) with BC Hydro. The Utility business is comprised of mainly natural gas distribution utilities. The utilities are allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the capital investment base. AltaGas owns and operates utility assets that deliver natural gas to end users in Alberta, British Columbia, and Nova Scotia. AltaGas also owns a one-third interest in the utility which delivers natural gas to end-users in Inuvik, Northwest Territories. The Utility business is comprised of AltaGas Utilities Inc. (AUI), the Alberta utility business, Pacific Northern Gas Ltd. (PNG), the British Columbia utility business and Heritage Gas Limited (Heritage Gas), the Nova Scotia utility.

On February 1, 2012, AltaGas and AltaGas Utility Holdings (U.S.) LLC (AUH(US)) entered into an agreement with Continental Energy Systems LLC (Continental) and SEMCO Holding Corporation (SEMCO) pursuant to which AUH(US) agreed to acquire all of the issued and outstanding shares of SEMCO for aggregate consideration of US$1.135 billion, subject to adjustment, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy Inc. (SEMCO Energy), a privately held regulated public utility company headquartered in Port Huron, Michigan, with natural gas distribution operations in Alaska and Michigan. The closing of the acquisition is subject to receipt of required regulatory approvals and the satisfaction or waiver of certain closing conditions. The closing of the acquisition is expected to occur in third quarter 2012. On March 2, 2012, the Federal Trade Commission has granted approval of the application for early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP). These unaudited interim Consolidated Financial Statements have been restated to give effect to the results of operations financial position and cash flows as if US GAAP had always been applied.

Pursuant to National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards (NI 52-107), US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

These unaudited interim Consolidated Financial Statements of AltaGas Ltd. include the accounts of the Corporation and all of its wholly owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership including Younger, Sarnia Airport Storage Pool Limited (Sarnia Storage), Alton Natural Gas Storage (Alton), ASTC Power Partnership (ASTC), McNair Creek Hydro Limited Partnership, Inuvik Gas Ltd. (Inuvik Gas), Ikhil Joint Venture, Craven LP, LLC and Grayling Generating Station Limited Partnership. Transactions between AltaGas Ltd. and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “Non-controlling interests” in the consolidated financial statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries is shown as an allocation of the consolidated net income and is presented separately in the "net income applicable to non-controlling interests".

These unaudited interim Consolidated Financial Statements do not contain all disclosures required by US GAAP for annual Consolidated Financial Statements. Note 20 to these unaudited interim Consolidated Financial Statements detail the Canadian GAAP to US GAAP transition and reconciliation information.

SIGNIFICANT ACCOUNTING POLICIES

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method assets and liabilities of the acquired entity are recorded at fair value. Acquisition-related costs are expensed immediately. The excess of the consideration transferred over the fair value of the assets and liabilities acquired is recognized as goodwill.

Rate-Regulated Operations

AltaGas Utilities Inc. (AUI), Heritage Gas, Pacific Northern Gas Ltd. (PNG) and Inuvik Gas (collectively "Utilities") engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC), Nova Scotia Utility and Review Board (NSUARB), British Columbia Utilities Commission (BCUC) and the Northwest Territories Public Utilities Board (NWTPUB), respectively.

The AUC, NSUARB and BCUC exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC, NSUARB and BCUC, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive commodity market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that will be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are to be refunded to customers through the rate-setting process.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, balances with banks and investments in money market instruments with original maturities of less than three months.

Inventory

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

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by AltaGas and therefore they are separately presented as restricted cash holdings from customers in the consolidated balance sheet. Any corresponding liability is classified as customer deposits within current liabilities.

Cash deposited by customers under the terms of natural gas utility service rules is unrestricted and is available for general use by respective rate-regulated subsidiaries of AltaGas. As such these funds are included in cash and cash equivalents in the consolidated balance sheet. Any corresponding liability is classified as customer deposits within current liabilities.

Property, Plant and Equipment (PPE) and Amortization

Property, plant and equipment are carried at cost. 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 utilities 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 range of useful lives for AltaGas' property, plant and equipment is as follows:

Gas	
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

Power	
Power generation assets	20 - 30 years
Utilities	
Utilities assets	1 - 33 percent
Corporate	
Other assets	1 - 5 years

Leases are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases.

Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction (AFUDC). AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction. It is calculated as the mid-year cost of construction work-in-progress multiplied by the regulated percentage cost of capital. Capitalized overhead, administrative expenses and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers in future periods through depreciation charges.

As required by the respective regulatory authorities, net additions to utilities assets at Heritage Gas are not depreciated until the year after they are brought into active service and net additions to utilities assets at AUI are depreciated commencing in the year in which the assets are brought into active service. Pursuant to the NSUARB decision dated February 12, 2009, Heritage Gas was ordered to suspend amortization for regulatory purposes for the periods 2009 through 2011.

Intangible Assets

Energy arrangements, contracts and relationships are recorded at cost, and are amortized on a straight-line basis over their term or estimated useful life:

Energy services relationships	15-19 years
E&T contracts	10 - 20 years
Electricity service agreement	60 years
Software	28 - 120 months
Land rights	25 - 60 years
Franchises and consents	9 - 25 years

AltaGas owns 50 percent of two Sundance B Power Purchase Arrangements (PPAs) through its interest in the ASTC. ASTC is committed to purchasing all of the power from the two 353 MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses hereunder are accounted for using the equity method. Acquisition of the Sundance B PPAs required a capital outlay. AltaGas is obligated to make payments to the owners of the underlying generating units over the remaining term of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the power is recorded based on target generator availability. The capital outlay is included in the energy services relationships.

Other energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp., PremStar Energy Canada Ltd. (re-named AltaGas Energy Limited Partnership subsequent to acquisition), ECNG Canada Ltd. and Energetics Group Inc., and are amortized on a straight-line basis over the 15-year expected useful life of the relationships.

The E&T contracts were acquired through the acquisition of Taylor NGL Limited Partnership (Taylor) and are amortized on a straight-line basis over the average expected life of the contracts.

The electricity service agreement relates to the 60-year CPI indexed electricity purchase agreement (EPA) for the Forrest Kerr Project which is expected to be operational in July 2014. Until commercial operation, the asset is not subject to amortization.

Goodwill

Goodwill represents that portion of the consideration transferred on acquisitions which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but tested at least annually for impairment, or more often when impairment indicators exist.

Financial Instruments

AltaGas uses the settlement date for transactions to account for financial instruments. Any difference in value between the trade and settlement date for third-party transactions are recognized on the balance sheet and in net income or in OCI as appropriate.

All financial instruments, including derivatives, are recorded on the Consolidated Balance Sheet initially at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement is determined by classification.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, with subsequent changes in fair value are recorded in net income. AltaGas does not have any held-to-maturity financial instruments. Loans and receivables are recognized at amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value and changes to fair value are recorded through other comprehensive income (OCI). Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in other revenue.

Other financial liabilities not classified as held-for-trading are recognized at amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are not the same as those of a stand-alone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the normal purchase and sale exemption, are carried on the Consolidated Balance Sheet at fair value.

Hedges

As part of its risk management strategy, AltaGas uses derivatives to reduce its exposure to commodity price, interest rate and foreign exchange risk. AltaGas designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. AltaGas performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item.

The effective portion of changes in the fair value of cash flow hedges is recognized in OCI. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by using the equity method. Other long-term investments are recorded at cost or designated as available-for-sale or held-for-trading. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost.

Development Costs

AltaGas expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations. Certain utility assets will have future legal obligations on retirement but an asset retirement obligation has not been recorded due to their indeterminate life, and corresponding indeterminable timing and scope of these asset retirement obligations.

Revenue Recognition

In the Gas reporting segment, the extraction and transmission, field gathering and processing and energy services operations recognize revenue at the time the product or service is delivered.

The Power reporting segment recognizes revenue at the time the product or service is delivered.

The Utility reporting segment recognizes revenue when the product or service is delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate-setting mechanism mandated by the applicable regulatory authority.

Realized gains and losses from risk management activities related to commodity prices are recognized when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheet. Unrealized gains and losses in respect of fair value changes to AltaGas' risk management activities which do not meet the criteria as effective hedges are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate reporting segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred. For financial instruments classified as other than held-for-trading transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate, a shorter period, to the net carrying amount of the financial asset or liability.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the average exchange rate applicable to the period.

Share-Based Compensation Plans

Pursuant to the Arrangement, AltaGas Ltd. assumed the obligations of the Trust in respect of outstanding unit options. Upon exercise of the outstanding share 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.

AltaGas follows the fair value method of accounting for share options granted to certain employees, including officers. Share options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by AltaGas on exercise of the option rights is credited to shareholders' capital.

AltaGas uses the Black-Scholes model to determine the fair value of the options on their grant date and recognizes the share-based compensation cost over the vesting period.

AltaGas has a share-based compensation plan in which participants receive phantom shares requiring settlement in cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom shares is recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheets.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost is the sum of the individual current service costs, and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 15.3 years and 13.2 years respectively.

Unamortized actuarial gains (losses) and transitional obligations are initially recognized in the other comprehensive income (losses) and amortized on a straight-line basis over the average remaining service life of active employees for the respective plan through the income statement.

Income Taxes

Prior to July 1, 2010 the Trust was a taxable entity under the Income Tax Act (Canada), and its income that was not paid or payable to the unitholders in a particular taxation year was taxable. The Trust allocated all of its taxable income to the unitholders in accordance with its Trust Indenture and met the requirements of the Income Tax Act (Canada). Accordingly, no provision for current income tax expense was made for the Trust. Temporary differences occurred when the book carrying value of the Trust’s assets and liabilities for accounting purposes differed from the amounts attributed to these same assets and liabilities for tax purposes. A tax rate of nil was applied to any temporary differences reversing before 2012.

After July 1, 2010 income taxes for the Corporation and its subsidiaries are calculated using the liability method of tax accounting. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax bases of assets and liabilities and are measured using the enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.
The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future rates and recovered from or paid to customers in the future.

Net Income per Share

Basic net income per share is calculated on the basis of the weighted average number of common shares during the period. Diluted net income per share is calculated as if the proceeds obtained upon exercise of options were used to purchase shares at the average market price during the period plus the shares issuable on conversion of outstanding convertible debentures and warrants.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. Cost is deemed to be the fair value as no active market currently exists for emission credits.

Use of Estimates and Measurement Uncertainty

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

CHANGE IN ACCOUNTING POLICIES

Balance Sheet Disclosures (Topic 210) about Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. Accounting Standards Update (ASU) Number (No.) 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. AltaGas is currently evaluating the impact of the standard on the financial statements.

Asset impairment - Intangibles Assets and Goodwill

Effective January 1, 2012, AltaGas has adopted ASU No. 2011-08, "Intangibles – Goodwill and Other". This new approach is used when events or circumstances indicate that goodwill may be impaired. In line with this standard, AltaGas' reporting segments will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting segment's goodwill may not be recoverable if the carrying amount of the reporting segment as a whole exceeds the reporting segment's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Comprehensive Income and Equity

In June 2011, FASB issued ASU No. 2011-05, "Other Comprehensive Income". This standard amends Accounting Standards Codification (ASC) 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The adoption of this update changes the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the financial statements. The amendment is effective January 1, 2012.

3. BUSINESS ACQUISITION

Decker Energy International Inc.

On November 23, 2011, AltaGas DEI Acquisition Inc. entered into an Agreement and Plan of Merger with Decker Energy International Inc. (DEI). Pursuant to this, AltaGas DEI Acquisition Inc. merged with DEI on January 26, 2012 to form DEI. At this time, DEI became an indirect wholly owned subsidiary of AltaGas. DEI is an independent power company whose primary assets are comprised of a 30 percent working interest in the 37 MW Grayling Generating Station in Michigan – a wood biomass power facility, and a 50 percent working interest in the 48 MW Craven County wood biomass power facility in North Carolina. Fuel supply for the biomass facilities include wood chips, mill residuals and other wood waste products from several suppliers. These assets are fully contracted with long-term Power Purchase Arrangements (PPAs).

AltaGas paid cash for an aggregate purchase price of $34.7 million. Transaction costs related to the acquisition cost amounted to $1.4 million and were expensed in the Consolidated Income Statement.

4. GOODWILL

	March 31 2012	December 31 2011
Balance, beginning of period	$ 281,123	$ 222,602
Acquisition	-	58,595
US GAAP transitional adjustment *(note 20)*	-	(74)
Balance, as at March 31, 2012	$ 281,123	$ 281,123

5. LONG-TERM DEBT

	March 31 2012	December 31 2011 (restated)
Credit facilities	$ 320,248	$ 38,962
Medium-term notes	1,075,000	1,175,000
Debentures notes	87,368	87,375
Loan from Province of Nova Scotia	4,882	4,815
Capital lease obligations	-	4,567
Promissory notes	3,839	3,839
Other long-term debt	4,846	5,702
	1,496,183	1,320,260
Less current portion	7,005	105,962
	$ 1,489,178	$ 1,214,298

Credit Facilities

As at March 31, 2012, AltaGas held a $600 million unsecured extendible revolving four-year credit facility with a syndicate of Canadian chartered banks. The facility matures on May 30, 2016. The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. As at March 31, 2012, AltaGas had $156.0 million of bankers acceptances (December 31, 2011 - $8.0 million) under the syndicated facility.

The Utility Group $200 million facility matures 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. As at March 31, 2012, AltaGas had $164.2 million of bankers acceptances outstanding (December 31, 2011 - $30.4 million) under the Utility Group facility.

On March 2, 2012, AltaGas obtained a US$300 million, unsecured credit facility maturing on March 2, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptance equivalent loans. At March 31, 2012, AltaGas had $nil outstanding under the facility.

Medium-Term Notes ("MTNs")

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.

On October 17, 2011, AltaGas issued $200 million of 4.55 percent senior unsecured MTNs. The notes mature of January 17, 2019.

Debentures Notes

As at March 31, 2012, AltaGas had $20.0 million outstanding (December 31, 2011 - $20.0 million) under the PNG 5 year Revolver due January 30, 2015, bearing interest at a floating rate at March 31, 2012 of 4.35 percent (December 31, 2011 - 4.35 percent).

As at March 31, 2012, AltaGas had $13.1 million outstanding (December 31, 2011 - $13.4 million) under the PNG RoyNat Debenture due September 15, 2017, bearing interest at a floating rate at March 31, 2012 of 3.7 percent (December 31, 2011 - 3.7 percent), payable in monthly installments of $0.1 million, beginning on September 15, 2010, with a final installment of $6.6 million at maturity.

As at March 31, 2012, AltaGas had $12.2 million outstanding (December 31, 2011 - $12.2 million) under the PNG 2018 Series Debenture, 8.75 percent due November 15, 2018, payable in annual installments of $0.6 million through to 2013 and $1.0 million in each of the years 2014 to 2017, with a final installment of $7.0 million at maturity.

As at March 31, 2012, AltaGas had $16.0 million outstanding (December 31, 2011 - $16.0 million) under the PNG 2025 Series Debenture, 9.30 percent due July 18, 2025, payable in annual installments of $0.5 million, with a final installment of $9.5 million at maturity.

As at March 31, 2012, AltaGas had $17.0 million outstanding (December 31, 2011 - $17.0 million) under the PNG 2027 Series Debenture, 6.90 percent due December 2, 2027, payable in annual installments of $0.5 million, with a final installment of $9.5 million at maturity.

Collateral for each the above Secured Debentures consists of a specific first mortgage on substantially all of PNG's plant, property and equipment and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

As at March 31, 2012, AltaGas had $8.7 million outstanding (December 31, 2011 - $8.8 million) under the PNG 2024 CFI Debenture, 7.39 percent due November 1, 2024, payable in monthly blended principal and interest mortgage style installments that total to $1.1 million annually. Collateral for the 2024 CFI Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek and a first security interest over all the interests of PNG and its partner in partnership interests and shares in McNair Creek.

Loan from Province of Nova Scotia

The loan has a face value of $5.6 million, is non-interest bearing and if certain prescribed revenue targets are achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. Heritage Gas may also elect to fully repay the loan at any time with no penalty. The loan is recorded at its amortized cost of $4.9 million as at March 31, 2012 (December 31, 2011 - $4.8 million). Interest expense is recorded at the effective interest rate of 6 percent.

Capital Lease Obligations

On September 1, 2004 AltaGas entered into a 10-year capital lease for 25 MW of gas-fired power peaking capacity with an option to extend the term for an additional 15 years. The lease was terminated during first quarter 2012, and the leased assets were acquired by AltaGas.

Promissory Note

AltaGas has a promissory note agreement with a Chartered Bank as lender maturing on October 25, 2015. On January 17, 2011, the lender advanced the available funds under the promissory note agreement.

Letter of Credit Facilities

As at March 31, 2012, AltaGas held a $75 million unsecured four-year extendible revolving letter of credit facility with two Canadian chartered banks maturing on May 30, 2016. 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 draws made. As at March 31, 2012, AltaGas had letters of credit of $64.7 million (December 31, 2011 - $67.7 million) outstanding against the extendible revolving letter of credit facility.

On April 26, 2011, AltaGas closed a $125 million unsecured bilateral letter of credit facility. AltaGas may borrow by way of letters of credit under the facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. As at March 31, 2012, AltaGas had $124.3 million letters of credit outstanding under the bilateral facility.

6. NORTHWEST TRANSMISSION LINE

In 2010, AltaGas entered into a 60-year Indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project. As at March 31, 2012, AltaGas is obligated to pay approximately $69.3 million over the next twenty-seven months to BC Hydro in support of the construction and operation of the Northwest Transmission Line. $40.5 million of this amount is recorded in accounts payable and accrued liabilities and $28.8 million in other long-term liabilities.

7. CAPITAL DISCLOSURE

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

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. AltaGas' target debt-to-total capitalization ratio is approximately 50 percent. AltaGas' debt-to-total capitalization ratio as at March 31, 2012, was 52.3 percent (December 31, 2011 - 49.6 percent).

	March 31 2012	December 31 2011 (restated)
Debt		
Short-term debt	**$ 17,539**	$ 16,824
Current portion of long-term debt	**7,005**	105,962
Long-term debt	**1,489,178**	1,214,298
Less cash and cash equivalent	**(1,187)**	(2,875)
	1,512,535	1,334,209
Shareholders' equity	**1,379,963**	1,355,413
Total capitalization	**$ 2,892,498**	$ 2,689,622
Debt-to-total capitalization ratio (%)	**52.3**	49.6

All of the borrowing facilities have covenants customary for these 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.

The following table summarizes the Corporation's debt covenants for all credit facilities as at March 31, 2012:

Ratios	Debt covenant requirements
Debt-to-capitalization	not greater than 60 percent
EBITDA-to-interest expense	not less than 2.5x
Debt-to-capitalization (Utility Group)	not greater than 67.5 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

8. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

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

Fair Values of Financial Instruments

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

The fair value of long-term debt has been estimated based on discounted future interest and principal payments using estimated interest rates.

The carrying amount and fair values of AltaGas' financial assets and liabilities were as follows:

Summary of Fair Values March 31, 2012	Held-for-trading	Cash flow hedges	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents[1]	$ 1,187	$ -	$ -	$ -	$ -	$ -	$ 1,187
Short-term investment [1]	-	-	-	-	-	-	-
Accounts receivable[1]	-	-	209,624	-	-	9,519	219,143
Restricted cash holdings from customers[1]	-	-	26,009	-	-	-	26,009
Risk management assets (current)	53,766	236	-	-	-	-	54,002
Prepaid expense and other current assets[1]	-	-	2,304	-	-	4,865	7,169
Risk management assets (non-current)	22,455	-	-	-	-	-	22,455
Long-term investments and other assets	5,265	-	-	4,890	-	18,611	28,766
	$ 82,673	$ 236	$ 237,937	$ 4,890	$ -	$ 32,995	$ 358,731
Financial liabilities							
Accounts payable and accrued liabilities[1]	$ -	$ -	$ -	$ -	$ 62,240	$ 189,951	$ 252,191
Dividends payable	-	-	-	-	10,324	-	10,324
Short-term debt[1]	-	-	-	-	17,539	-	17,539
Current portion of long-term debt	-				7,005		7,005
Customer deposits[1]	-	-	-	-	31,750	-	31,750
Risk management liabilities (current)	58,923	2,248	-	-	-	-	61,171
Other current liabilities[1]	-				2,574	3,493	6,067
Long-term debt	-	-	-	-	1,489,178	-	1,489,178
Risk management liabilities (non-current)	22,052	-	-	-	-	-	22,052
Other long-term liabilities	-	-	-	-	-	28,800	28,800
	$ 80,975	$ 2,248	$ -	$ -	$ 1,620,610	$ 222,244	$ 1,926,077

[1] *Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.*

Summary of Fair Values December 31, 2011 (restated)	Held-for-trading	Cash flow hedges	Loans and receivables	Available for sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents[1]	$ 2,875	$ -	$ -	$ -	$ -	$ -	$ 2,875
Accounts receivable[1]	-	-	231,203	-	-	8,007	239,210
Restricted cash holdings from customers[1]	-	-	19,672	-	-	-	19,672
Risk management assets (current)	48,073	20,331	-	-	-	-	68,404
Prepaid expense and other assets[1]			2,594			6,048	8,642
Risk management assets (non-current)	21,586	56	-	-	-	-	21,642
Long-term Investments and other assets (note 8)	3,539	-	-	6,844	-	15,025	25,408
	$ 76,073	$ 20,387	$ 253,469	$ 6,844	$ -	$ 29,080	$ 385,853
Financial liabilities							
Accounts payable and accrued liabilities[1]	$ -	$ -	$ -	$ -	$ 77,923	$ 236,162	$ 314,085
Dividends payable[1]	-	-	-	-	10,264	-	10,264
Short-term debt[1]	-	-	-	-	16,824	-	16,824
Current portion of long-term debt					105,962		105,962
Customer deposits[1]	-	-	-	-	25,570	-	25,570
Risk management liabilities (current)	54,010	18,963	-	-	-	-	72,973
Other current liabilities[1]					1,716	9,609	11,325
Long-term debt	-	-	12,825	-	1,201,473	-	1,214,298
Risk management liabilities (non-current)	20,250	358	-	-	-	-	20,608
Other long-term liabilities	-	-	-	-	10	28,800	28,810
	$ 74,260	$ 19,321	$ 12,825	$ -	$1,439,742	$ 274,571	$ 1,820,719

[1] *Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.*

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

	Three Months Ended March 31 **2012**	2011 (restated)
Natural gas	**$ (4,132)**	$ 1,413
Storage optimization	**1,465**	(1,502)
NGL Frac Spread	**(3,968)**	(6,713)
Power	**8,752**	(449)
Heat rate	**(531)**	698
Interest rate swaps	**7**	(105)
Foreign exchange	**(436)**	(252)
	$ 1,157	$ (6,910)

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

	Unrealized losses	Tax recovery	As at March 31 2012	Unrealized losses	Tax recovery	As at March 31 2011 (restated)
NGL Frac Spread	**$ (2,248)**	**$ 562**	**$ (1,686)**	$ (1,262)	$ 322	$ (940)
Bond forward	**(1,508)**	**-**	**(1,508)**	(2,148)	-	(2,148)
Available-for-sale	**(5,137)**	**642**	**(4,495)**	(817)	106	(711)
OCI	**$ (8,893)**	**$ 1,204**	**$ (7,689)**	$ (4,227)	$ 428	$ (3,799)

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

	For Three Months Ended			For Three Months Ended		
	Unrealized Gains (losses)	**Tax (expense) recovery**	**March 31 2012**	Unrealized Gains (losses)	Tax (expense) recovery	March 31 2011 (restated)
NGL Frac Spread	**$ (741)**	**$ 185**	**$ (556)**	$ (497)	$ 754	$ 257
Bond forward	**165**	**-**	**165**	153	-	153
Available-for-sale	**1,600**	**(200)**	**1,400**	(2,499)	333	(2,166)
OCI	**$ 1,024**	**$ (15)**	**$ 1,009**	$ (2,843)	$ 1,087	$ (1,756)

Fair Value Hierarchy

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

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

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

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

March 31, 2012	Level 1	Level 2	Level 3	Total
Financial Assets				
Held-for-trading [(1)]	**5,265**	**76,221**	**-**	**81,486**
Cash flow hedges	**-**	**236**	**-**	**236**
Available for sale	**4,890**	**-**	**-**	**4,890**
Financial Liabilities				
Held-for-trading	**-**	**80,975**	**-**	**80,975**
Cash flow hedges	**-**	**2,248**	**-**	**2,248**

December 31, 2011 (restated)	Level 1	Level 2	Level 3	Total
Financial Assets				
Held-for-trading [(1)]	3,539	69,659	-	73,198
Cash flow hedges	-	20,387	-	20,387
Available for sale	6,844	-	-	6,844
Financial Liabilities				
Held-for-trading	-	74,260	-	74,260
Cash flow hedges	-	19,321	-	19,321

[(1)] *Excludes cash and cash equivalents as carrying amount approximates fair value.*

Long-term Investments and Other Assets

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (formerly Magma Energy Corp., "Alterra") through a private equity offering. These shares were classified as available for sale. The changes in fair value of these common shares are being reported in OCI, as an unrealized pre-tax gain of $1.6 million as at March 31, 2012 (March 31, 2011 - unrealized pre-tax loss of $2.5 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. All shares of Alterra are reported in long term investments and other assets.

Summary of Unrealized Gains (Losses) on Held-for-Trading Recognized in Net Income

	Three Months Ended	
	March 31, 2012	March 31, 2011
Financial assets held-for-trading	**$ 1,726**	$ (2,762)

9. SHAREHOLDERS' EQUITY

Authorization

As at March 31, 2012, 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 issued and outstanding common shares.

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.

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

Common Shares Issued and Outstanding	Number of shares	Amount
December 31, 2011	**89,248,374**	**$ 1,204,269**
Shares issued for cash on exercise of options	**280,200**	**5,727**
Shares issued under DRIP	**295,430**	**8,448**
Issued and outstanding at March 31, 2012	**89,824,004**	**$ 1,218,444**

	Three Months Ended March 31	
Weighted Average Shares Outstanding	**2012**	2011
Number of shares - basic	**89,491,534**	82,753,280
Dilutive equity instruments [1]	**1,373,832**	1,865,161
Number of shares - diluted	**90,865,366**	84,618,441

[1] *Includes in-the-money options*

Subscription Receipts

On February 22, 2012, AltaGas closed approximately $403.0 million in gross proceeds held in trust in connection with a subscription receipts offering for total consideration of 13,915,000 common shares. The subscription receipts offering represents the holder's right to receive one common share of the issuer contingent upon acquisition close. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. At March 31, 2012, 4,026,270 shares were reserved for issuance under the plan. As at March 31, 2012, options granted under the plan generally have a term of 10 years until expiry and vest no longer than over a four-year period.

As at March 31, 2012, outstanding options were exercisable at various dates within the next ten years. As at March 31, 2012, the unexpensed fair value of share option compensation cost associated with future periods was $4.9 million (December 31, 2011 - $5.8 million).

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

	Options outstanding	
	Number of options	**Exercise price[1]**
Share options outstanding, December 31, 2011	**5,337,705**	**$ 22.37**
Granted	**-**	**-**
Exercised	**(280,200)**	**19.69**
Cancelled/Forfeited	**(101,375)**	**(20.08)**
Share options outstanding, March 31, 2012	**4,956,130**	**$ 22.55**
Share options exercisable, March 31, 2012	**2,250,698**	**$ 21.40**

[1] *Weighted average.*

The following table summarizes the employee share option plan as at March 31, 2012:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted Average Exercise price	Weighted Average Remaining contractual life	Number exercisable	Exercise price
$7.25 to $15.25	639,705	$ 14.22	6.64	480,935	$ 14.21
$15.26 to $25.08	2,644,925	20.54	7.74	1,181,450	21.11
$25.09 to $31.82	1,671,500	28.93	7.82	588,313	27.84
	4,956,130	$ 22.55	7.62	2,250,698	$ 21.40

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. The phantom shares are valued based on dividends declared and the trading price of the Corporation's common shares. The shares vest on a graded vesting schedule over three years. The compensation expense recorded in first quarter 2012 in respect of this plan was $1.6 million (first quarter 2011 - $2.1 million). As at March 31, 2012, the unexpensed fair value of equity-based compensation costs associated with future periods was $14.0 million (first quarter 2011 - $14.8 million).

10. NET INCOME APPLICABLE TO COMMON SHARES

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

	Three Months Ended March 31	
	2012	2011 (restated)
Numerator:		
Net income applicable to common shares - basic	**$ 41,270**	$ 26,712
Net income applicable to common shares - diluted	**$ 41,270**	$ 26,712
Denominator:		
Weighted-average number of common shares outstanding	**89,491**	82,753
Dilutive equity instruments[1]	**1,374**	1,865
Number of shares outstanding - diluted	**90,865**	84,618
Basic net income applicable to common shares	**$ 0.46**	$ 0.32
Diluted net income applicable to common shares	**$ 0.45**	$ 0.32

[1] *Includes in-the-money options*

11. COMMITMENTS

On February 1, 2012, AltaGas Ltd. and a wholly owned subsidiary of AltaGas entered into a definitive agreement with Continental to acquire SEMCO for US$1.135 billion, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy, Inc. a privately held regulated public utility company headquartered in Port Huron, Michigan. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR and an 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 transaction is subject to customary approvals including regulatory approvals from the Michigan Public Service Commission, the Regulatory Commission of Alaska and expiration of the waiting period under the HSR. On March 2, 2012, the Federal Trade Commission granted the application for early termination of the waiting period under HSR. The closing of the acquisition is subject to receipt of required regulatory approvals and the satisfaction or waiver of certain closing conditions. The regulatory approval process is expected to take approximately six months and AltaGas expects the acquisition to close in the third quarter, 2012. The transaction is expected to be accounted for as a business acquisition using the acquisition method of accounting.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $12.7 million over the next 11 years, of which $5.3 million is payable in the next five years.

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

In 2010, AltaGas entered into a 60-year CPI indexed Electricity Purchase Agreement (EPA) with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project. At March 31, 2012, AltaGas is committed to pay approximately $162.4 million for construction work related to this project which is expected to be in service in mid-2014.

12. SUPPLEMENTAL CASH FLOW DISCLOSURES

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

	Three Months Ended March 31 2012	March 31 2011 (restated)
Accounts receivable	**$ 20,067**	$ 12,433
Inventory	**1,295**	3,240
Other current assets	**1,474**	415
Regulatory assets	**2,373**	(1,418)
Accounts payable and accrued liabilities	**(56,702)**	(54,061)
Dividends payable	**61**	47
Customer deposits	**6,181**	(1,915)
Regulatory liabilities	**2,265**	28
Other current liabilities	**(5,259)**	(5,919)
	(28,245)	(47,150)
Increase (decrease) in capital costs payable	**50,396**	17,920
Net change in non-cash working capital	**$ 22,151**	$ (29,230)

(1) *Specific line items may not agree with the net change in the Consolidated Balance Sheets due to acquisition* (Note 3)

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

	Three Months Ended March 31 2012	2011
Interest paid	**$ 15,056**	$ 8,172
Income taxes paid	**$ 5,070**	$ 2,644

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:

	Defined Benefit Plans		**Post-retirement Benefit Plans**	
For the three months ended March 31	**2012**	2011 (restated)	**2012**	2011 (restated)
Current service cost	**$ 1,144**	$ 1,188	**$ 102**	$ 92
Interest cost	**1,169**	1,108	**136**	131
Expected return on plan assets	**(869)**	(944)	**(15)**	(11)
Amortization of transitional obligation	**-**	-	**-**	31
Amortization of past service cost	**19**	19	**-**	-
Amortization of net actuarial loss	**215**	133	**20**	19
Net benefit cost recognized	**$ 1,678**	$ 1,504	**$ 243**	$ 262

14. RELATED PARTY TRANSACTIONS

AltaGas and one of its managers agreed on a loan in the principal amount of $750 thousand, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015. The loan is classified within the long-term investments and other assets and the interest is recognized in other revenue.

During first quarter 2012, AltaGas paid rent under a lease for office space and equipment to 2013761 Ontario Inc., which is partially owned by a former employee of AltaGas. Payments of $8 thousand were made in first quarter 2012 (first quarter 2011 - $23 thousand).

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 April 13, 2012, AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020. Net proceeds from the issuance will be used to reduce outstanding indebtedness and for general corporate purposes.

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. The following describes the Corporation's four reporting segments:

Gas	– NGL processing and extraction plants – transmission pipelines to transport natural gas and NGL – natural gas gathering lines and field processing facilities – energy consulting and purchase and sale of natural gas and electricity – natural gas storage facilities
Power	– coal-fired and gas-fired power output under power purchase arrangements – wind, run-of-river, gas-fired and biomass power plants – sale of power to commercial and industrial users in Alberta
Utilities	– regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia – one-third interest in gas production and distribution utility in 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 March 31, 2012 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 261,080	$ 59,416	$ 78,687	$ 1,813	$ (37,783)	$ 363,213
Unrealized gains on risk management contracts	-	-	-	1,157	-	1,157
Income from equity investments	95	11,954	96	-	-	12,145
Cost of sales	(173,654)	(36,806)	(35,512)	-	36,915	(209,057)
Operating and administrative	(42,854)	(5,077)	(18,854)	(7,812)	868	(73,729)
Accretion of asset retirement obligations	(758)	(28)	(29)	-	-	(815)
Depreciation, depletion and amortization	(13,800)	(2,543)	(4,960)	(887)	-	(22,190)
Foreign exchange loss	-	-	-	(134)	-	(134)
Interest expense	-	-	(4,371)	(8,390)	-	(12,761)
Income (loss) before income taxes	$ 30,109	$ 26,916	$ 15,057	$ (14,253)	-	$ 57,829
Net additions (reductions) to:						
Property, plant and equipment(1)	$ 84,223	$ 58,193	$ 4,971	$ 78	-	$ 147,465
Intangible assets	$ 900	$ (3)	135	16	-	$ 1,048
Long-term investment and other assets(1)	$ (101)	$ 35,968	$ 96	3,326	-	$ 39,289
Goodwill	$ 161,402	-	$ 119,721	-	-	$ 281,123
Segmented assets	$ 1,943,880	$ 810,412	$ 818,207	$ 123,623	-	$ 3,696,122

(1) *Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition (note 3)*

Three Months Ended March 31, 2011 (unaudited and restated)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 307,991	$ 43,033	$ 61,278	$ (3,011)	$ (44,020)	$ 365,271
Unrealized (losses) on risk management contracts	-	-	-	(6,910)	-	(6,910)
Income from equity investments	281	25,641	197	-	-	26,119
Cost of sales	(220,742)	(36,532)	(35,347)	-	44,365	(248,256)
Operating and administrative	(43,228)	(2,985)	(11,403)	(6,209)	(345)	(64,170)
Accretion of asset retirement obligations	(596)	(12)	-	-	-	(608)
Depreciation, depletion and amortization	(13,530)	(2,571)	(3,068)	(884)	-	(20,053)
Foreign exchange gain	-	-	-	38	-	38
Interest expense	-	-	(2,825)	(10,079)	-	(12,904)
Income (loss) before income taxes	$ 30,176	$ 26,574	$ 8,832	$ (27,055)	-	$ 38,527
Net additions (reductions) to:						
Property, plant and equipment	(3,028)	29,230	4,717	1,803	-	$ 32,722
Intangible assets	727	-	-	34	-	$ 761
Long-term investment and other assets	-	-	(201)	(6,824)	-	$ (7,025)
Goodwill	161,402	-	61,200	-	-	$ 222,602
Segmented assets	$ 1,660,087	$ 478,595	$ 490,728	$ 215,931	-	$ 2,845,341

20. US GAAP TRANSITION

ADOPTION OF US GAAP

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

On September 10, 2010, the 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. The Canadian Securities Administrators provide for a similar one year deferral pursuant to National Instrument 52-107 "Acceptable Accounting Principles and Auditing Standards" (NI 52-107).

AltaGas is a qualified entity for the deferral period permitted by AcSB and NI 52-107. AltaGas has elected to use the deferral offered by the AcSB and NI 52-107 given the uncertainty with respect to the application of IFRS to the RRA. In 2011, AltaGas reassessed the accounting policy choices available and decided to adopt US GAAP effective January 1, 2012.

Pursuant to NI 52-107, US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under US securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

For financial reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Corporation’s 2012 financial statements. Consolidated financial statements have been restated to give effects to the results of financial positions, operations and cash flows as if US GAAP has always been applied.

Measurement, classification and disclosure differences arising out of the Corporation’s election to adopt US GAAP are presented below. With respect to measurement and classification differences, Section I “US GAAP differences” presents quantitative reconciliations of balance sheets, statements of income and statements of cash flows, previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with the descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP.

Balance sheet reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. Statement of income, statement of other comprehensive income and accumulated other comprehensive loss and statement of cash flow reconciliations are presented for the three months ended March 31, 2011 and for the year ended December 31, 2011.

In addition, US GAAP requires certain disclosures of financial information, significant to the Corporation, that are in addition to the required disclosure under Canadian GAAP. This information, which is as at December 31, 2011, is presented in Section II “Additional disclosures required under US GAAP”.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP financial statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

Section I – US GAAP differences

The following table summarizes the change in total assets:

($ thousands)	Notes	January 1, 2011	December 31, 2011
Total assets - Canadian GAAP		$ 2,752,538	$ 3,542,420
Business combinations	A	(2,757)	(2,757)
Accounting for joint ventures	B	(16,394)	(13,180)
Pension and other post-retirement benefits	C	1,025	15,352
Natural gas held in storage	D	(903)	1,228
Debt financing costs	F	9,470	12,825
Total assets - US GAAP		$ 2,742,979	$ 3,555,888

The following table summarizes the change in total liabilities:

$ thousands)	Notes	January 1, 2011	December 31, 2011
Total liabilities - Canadian GAAP		$ 1,541,507	$ 2,180,280
Business combinations	A	(5,971)	(5,971)
Accounting for joint ventures	B	(16,394)	(13,180)
Pension and other post-retirement benefits	C	5,887	19,792
Natural gas held in storage	D	(255)	278
Debt financing costs	F	9,470	12,825
Income tax on preferred share dividends	G	275	1,025
Total liabilities - US GAAP		$ 1,534,519	$ 2,195,049

The following table summarizes the increases (decreases) to net income:

($ thousands)	3 months ended March 31 2011	Year ended December 31 2011
Net income applicable to common shares - Canadian GAAP	$ 26,553	$ 83,602
C. Pension and other post-retirement benefits	(33)	432
D. Natural gas held in storage	(29)	1,598
E. De-designation of cash flow hedges	409	(2,114)
G. Income tax on preferred share dividends	(188)	(750)
Total transition adjustments	159	(834)
Net income applicable to common shares - US GAAP	$ 26,712	$ 82,768
Net income applicable to common shares - basic per share - Canadian GAAP	$ 0.32	$ 0.99
Effect of US GAAP transition	-	(0.01)
Net income applicable to common shares - basic per share - US GAAP	$ 0.32	$ 0.98

The reconciliations of Balance Sheets from Canadian GAAP to US GAAP are as follows:

As at January 1, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 2,109	(1,086)	$ 1,023
Accounts receivable	B	225,217	(16,132)	209,085
Inventory	D	13,106	(903)	12,203
Restricted cash holdings from customers		17,624	-	17,624
Regulatory assets		2	-	2
Risk management assets		41,226	-	41,226
Prepaid expense and other current assets	B, C & F	5,587	(274)	5,313
		304,871	(18,395)	286,476
Property, plant and equipment	A, B	1,976,538	(53,006)	1,923,532
Intangible assets	B	139,942	(59,919)	80,023
Goodwill	A & B	199,497	23,105	222,602
Regulatory assets	C	76,515	1,406	77,921
Risk management assets		22,587	-	22,587
Long-term investments and other assets	C & F	32,588	5,338	37,926
Investments accounted for by equity method	B	-	91,912	91,912
		$ 2,752,538	(9,559)	$ 2,742,979
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	$ 229,618	(16,245)	$ 213,373
Dividends payable		9,078	-	9,078
Short-term debt		9,478	-	9,478
Current portion of long-term debt		1,508	-	1,508
Customer deposits		21,432	-	21,432
Regulatory liabilities		1,494	-	1,494
Risk management liabilities		39,209	-	39,209
Other current liabilities	B	12,302	(52)	12,250
		324,119	(16,297)	307,822
Long-term debt	F	893,498	9,470	902,968
Asset retirement obligations		39,516	-	39,516
Deferred income taxes	A, B, C, D & G	233,763	(7,724)	226,039
Regulatory liabilities		18,518	-	18,518
Risk management liabilities		20,598	-	20,598
Other long-term liabilities		15	-	15
Future employee obligations	C	11,480	7,563	19,043
		1,541,507	(6,988)	1,534,519
Common shares		1,023,033	-	1,023,033
Preferred shares		194,126	-	194,126
Contributed surplus		5,672	-	5,672
Accumulated other comprehensive (loss) income	C & E	(2,752)	(2,880)	(5,632)
Accumulated deficit	A, C, D, E & G	(9,048)	309	(8,739)
		$ 2,752,538	(9,559)	$ 2,742,979

As at March 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 111,183	(1,385)	$ 109,798
Accounts receivable	B	209,725	(13,073)	196,652
Inventory	B & D	9,907	(943)	8,964
Restricted cash holdings from customers		15,875	-	15,875
Regulatory assets		1,420	-	1,420
Risk management assets		39,967	-	39,967
Prepaid expense and other current assets	B, C & F	5,045	(310)	4,735
		393,122	(15,711)	377,411
Property, plant and equipment	A, B	2,010,268	(52,987)	1,957,281
Intangible assets	B	122,317	(62,427)	59,890
Goodwill	A & B	199,497	23,105	222,602
Regulatory assets	C	76,742	(1,292)	75,450
Risk management assets		24,188	-	24,188
Long-term investments and other assets	C & F	25,562	9,649	35,211
Investments accounted for by equity method	B	-	93,308	93,308
		$ 2,851,696	(6,355)	$ 2,845,341
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	$ 173,161	(13,849)	$ 159,312
Dividends payable		9,125	-	9,125
Short-term debt		840	-	840
Current portion of long-term debt		105,859	-	105,859
Customer deposits		19,517	-	19,517
Regulatory liabilities		1,522	-	1,522
Risk management liabilities		43,445	-	43,445
Other current liabilities	B	7,237	(1,791)	5,446
		360,706	(15,640)	345,066
Long-term debt	F	937,179	10,253	947,432
Asset retirement obligations		39,990	-	39,990
Deferred income taxes	A, B, C, D & G	241,395	1,853	243,248
Regulatory liabilities		19,094	-	19,094
Risk management liabilities		21,038	-	21,038
Other long-term liabilities		6,400	-	6,400
Future employee obligations		5,476	-	5,476
		1,631,278	(3,534)	1,627,744
Common shares		1,034,673	-	1,034,673
Preferred shares		194,126	-	194,126
Contributed surplus		5,542	-	5,542
Accumulated other comprehensive (loss) income	C & E	(4,099)	(3,289)	(7,388)
Accumulated deficit	A, C, D, E & G	(9,824)	468	(9,356)
		$ 2,851,696	(6,355)	$ 2,845,341

As at December 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 4,220	(1,345)	$ 2,875
Accounts receivable	B	251,215	(12,005)	239,210
Inventory	B & E	11,332	1,135	12,467
Restricted cash holdings from customers		19,672	-	19,672
Regulatory assets		5,141	-	5,141
Risk management assets		68,404	-	68,404
Prepaid expense and other current assets	B, C & F	8,427	215	8,642
		368,411	(12,000)	356,411
Property, plant and equipment	A & B	2,540,215	(54,165)	2,486,050
Intangible assets	B	232,685	(55,169)	177,516
Goodwill	A, B & C	258,092	23,031	281,123
Regulatory assets	C	104,786	15,808	120,594
Risk management assets		21,642	-	21,642
Long-term investments and other assets	B, C & F	16,589	8,819	25,408
Investments accounted for by equity method	B	-	87,144	87,144
		$ 3,542,420	13,468	$ 3,555,888
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	327,143	(13,058)	314,085
Dividends payable		10,264	-	10,264
Short-term debt		16,824	-	16,824
Current portion of long-term debt		105,962	-	105,962
Customer deposits		25,570	-	25,570
Regulatory liabilities		503	-	503
Risk management liabilities		72,973	-	72,973
Other current liabilities	B	11,314	11	11,325
		570,553	(13,047)	557,506
Long-term debt	G	1,201,473	12,825	1,214,298
Asset retirement obligations		44,318	-	44,318
Deferred income taxes	A, B, C, D & G	272,272	(6,490)	265,782
Regulatory liabilities		26,686	-	26,686
Risk management		20,608	-	20,608
Other long-term liabilities		28,810	-	28,810
Future employee obligations	C	15,560	21,481	37,041
		2,180,280	14,769	2,195,049
Common shares		1,204,269	-	1,204,269
Preferred shares		194,126	-	194,126
Contributed surplus		7,441	-	7,441
Accumulated other comprehensive loss	C & E	(11,522)	(775)	(12,297)
Accumulated deficit	A, C, D, E & G	(37,600)	(526)	(38,126)
Non-controlling interests		5,426	-	5,426
		$ 3,542,420	13,468	$ 3,555,888

The adjustments to March 31, 2011 equity are as follows:

($ thousands)	Common Shares	Preferred Shares	Contributed Surplus	Accumulated OCI	Retained Earnings	Total Equity
Canadian GAAP	**1,034,673**	**194,126**	**5,542**	**(4,099)**	**(9,824)**	**$ 1,220,418**
A. Business combinations	-	-	-	-	3,214	3,214
C. Pension and other post-retirement benefits	-	-	-	(3,591)	(1,305)	(4,896)
D. Natural gas held in storage	-	-	-	-	(677)	(677)
E. De-designation of cash flow hedges	-	-	-	302	(302)	-
G. Income tax on preferred share dividends	-	-	-	-	(463)	(463)
US GAAP	**1,034,673**	**194,126**	**5,542**	**(7,388)**	**(9,357)**	**$ 1,217,596**

The statements of income for three months ended March 31, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

($ thousands except per share amounts)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
REVENUE				
Operating	B	413,871	(45,499)	368,372
Unrealized (loss) on risk management contracts	D & E	(7,427)	517	(6,910)
Other (expenses) revenue	B	(3,011)	(90)	(3,101)
Income from equity investments	B	-	26,119	26,119
		403,433	(18,953)	384,480
EXPENSES				
Cost of sales	B	265,697	(17,441)	248,256
Operating and administrative	B	64,476	(306)	64,170
Accretion of asset retirement obligations		608	-	608
Depreciation, depletion and amortization	B	21,666	(1,613)	20,053
		352,447	(19,360)	333,087
Foreign exchange loss (gain)		(38)	-	(38)
Interest expense				
Short-term debt		177	-	177
Long-term debt		12,727	-	12,727
Income before income taxes		38,120	407	38,527
Income tax expense (recovery)				
Current	B & G	1,195	923	2,118
Deferred	D, E & G	7,622	(425)	7,197
Net income after taxes		29,303	(91)	29,212
Preferred share dividends	G	2,750	(250)	2,500
Net income applicable to common shares		26,553	159	26,712
Net income applicable to common share (per share)				
Basic		0.32	-	0.32
Diluted		0.31	0.01	0.32
Weighted average number of shares outstanding				
Basic		82,753	-	82,753
Diluted		84,618	-	84,618

The statements of comprehensive income and accumulated other comprehensive loss for three months ended March 31, 2011 and for the year ended December 31, 2011 reconciled from Canadian GAAP to US GAAP are as follows:

For the three months ended March 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net income after taxes		29,303	(91)	29,212
Other comprehensive (loss) income, net of tax				
Unrealized income (loss) gain on available-for-sale financial assets (net of tax of $.33 million)		(2,166)	-	(2,166)
Unrealized income (loss) on derivatives designated as cash flow hedges (net of tax of ($.11) million)	E	409	(152)	257
Reclassification to net income of net (loss) gain on derivatives designated as cash flow hedges pertaining to prior periods	E	410	(257)	153
		(1,347)	(409)	(1,756)
Comprehensive income		27,956	(500)	27,456
Accumulated other comprehensive loss, beginning of period	C & E	(2,752)	(2,880)	(5,632)
Other comprehensive loss, net of tax		(1,347)	(409)	(1,756)
Accumulated other comprehensive loss, end of period		(4,099)	(3,289)	(7,388)

For the year ended December 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net income after taxes		94,602	(1,834)	92,768
Other comprehensive (loss) income, net of tax				
Unrealized income (loss) gain on available-for-sale financial assets (net of tax of $.11 million)		(7,350)	-	(7,350)
Unrealized income (loss) on derivatives designated as cash flow hedges (net of tax of ($.06) million)	E	(2,304)	2,371	67
Reclassification to net income of net (loss) gain on derivatives designated as cash flow hedges pertaining to prior periods	E	884	(256)	628
Net loss arising during the period from pension and post-retirement benefit plans	C	-	(10)	(10)
		(8,770)	2,105	(6,665)
Comprehensive income		85,832	271	86,103
Accumulated other comprehensive loss, beginning of year	C & E	(2,752)	(2,880)	(5,632)
Other comprehensive loss, net of tax		(8,770)	2,105	(6,665)
Accumulated other comprehensive loss, end of year		(11,522)	(775)	(12,297)

The consolidated statements of cash flows for three months ended March 31, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

($ thousands)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	35,819	(3,587)	32,232
Net cash used in investing activities	B	(46,952)	2,288	(44,664)
Net cash provided by financing activities		120,207	1,000	121,207
Change in cash and cash equivalents		109,074	(299)	108,775
Cash and cash equivalents, beginning of period	B	2,109	(1,086)	1,023
Cash and cash equivalents, end of period	B	111,183	(1,385)	109,798

Notes to transitional adjustments

US GAAP discloses certain assets, liabilities, revenues and expenses on different lines in the financial statements compared to Canadian GAAP.

A. Business Combinations

Definition of business combinations

The criteria for determining the nature of transactions included in the scope of the ASC 805 differs from the criteria used under Canadian GAAP. The ASC 805 definition of a business focuses on an integrated set of activities and assets that is capable of providing a return. This requires that the integrated set include inputs and processes applied to those inputs which, together are or will be used to create outputs, but does not necessarily require that it currently include outputs. For this reason, entities considered to be in the development stage could meet the definition of a business under US GAAP. In March 2010, AltaGas acquired an entity and the transaction was accounted for under Canadian GAAP as an asset acquisition on the basis that it was a development stage entity. Under US GAAP this acquisition is accounted for as a business acquisition.

The effect on the balance sheets is reflected with the following increases (decreases):

($ thousands)	January 1 2011	December 31 2011
Property, plant and equipment	(25,932)	(25,932)
Goodwill	18,635	18,635
Future income taxes	7,297	7,297

Acquisition-related transaction costs

Under Canadian GAAP, Part V Handbook 1581 and until December 31, 2010, acquisition-related transaction costs were capitalized and included in the allocation of the purchase price to the acquired assets and assumed liabilities. Under US GAAP, acquisition-related transaction costs are expensed in the period incurred, beginning with transactions completed on or after January 1, 2009. After January 1, 2011, business combinations have been accounted for in accordance with Canadian GAAP, Part V Handbook 1582, with the same accounting treatment of acquisition-related transaction costs as per US GAAP.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Accumulated deficit	(3,051)	(3,051)
Goodwill	(4,284)	(4,284)
Deferred income taxes	(1,233)	(1,233)

Business combinations achieved in stages
Until December 31, 2010 under Canadian GAAP, Part V Handbook 1581, for business combinations achieved in stages, the acquirer does not re-measure its previously held equity interest in an acquired company. Under ASC 805, the acquirer re-measures the previously held equity interest at the acquisition-date fair value and recognizes the resulting gain or loss, if any, in income, beginning with transactions completed on or after January 1, 2009. After January 1, 2011, business combinations have been accounted for in accordance with Canadian GAAP, Part V Handbook 1582, with the same accounting treatment for business combinations achieved in stages as is required under ASC 805.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Accumulated deficit	6,265	6,265
Goodwill	8,824	8,824
Deferred income taxes	2,559	2,559

The combined effect on the balance sheets of the adoption of ASC 805 is as follows:

($ thousands)	January 1 2011	December 31 2011
Total assets		
Property, plant and equipment	(25,932)	(25,932)
Goodwill	23,175	23,175
Total liabilities		
Deferred income taxes	(5,971)	(5,971)
Equity		
Accumulated deficit	3,214	3,214

B. Accounting for Joint Ventures

The Corporation exercises joint control but not control over its investments in ASTC, Inuvik Gas, Sarnia Storage and Alton. Under Canadian GAAP, these investments were proportionately consolidated. Under the proportionate consolidation method, the Corporation recognized its pro-rata share of the jointly controlled assets and liabilities and of the jointly controlled entities in the consolidated balance sheets and recognized its pro-rata share of the revenues and expenses of the jointly controlled assets and liabilities and of the jointly controlled entities in the consolidated income statement.

Under US GAAP, the Corporation accounts for its investments in jointly controlled legal entities and most limited partnerships using the equity method whereby the amount of the Corporation's investment is adjusted quarterly for the

Corporation's pro-rata share of their net income or loss and reduced by the amount of any cash distribution received. The Corporation's pro-rata share of the entities' net income is recognized in the item “Income from equity investments” in the Statement of Income.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Cash and cash equivalents	(1,086)	(1,345)
Accounts receivable	(16,132)	(12,005)
Inventory	-	(93)
Prepaid expenses and other current assets	(91)	(201)
Property, plant and equipment	(27,074)	(28,232)
Intangible assets	(59,919)	(55,169)
Long-term investments and other assets	-	344
Goodwill	(70)	(70)
Total assets	(104,372)	(96,771)
Accounts payable and accrued liabilities	(16,245)	(13,058)
Other current liabilities	(52)	11
Deferred income taxes	(97)	(133)
Total liabilities	(16,394)	(13,180)
Investments accounted for by equity method	87,978	83,591

Presentation of equity method investments
Under Canadian GAAP, the Corporation accounted for its investment in Boston Bar Limited Partnership using the equity method. The investment was classified within 'Long-term investment and other non-current assets' and the income associated with this investment was classified in the income statement within 'Other revenue'.

Under US GAAP, the investment in Boston Bar Limited Partnership is classified within 'Investments accounted for by equity method' and income is classified within 'Income from equity investments'.

The effect on the balance sheets of this reclassification is as follows:

($ thousands)	January 1 2011	December 31 2011
Long-term investment and other assets	(3,933)	(3,553)
Investments accounted for by equity method	3,933	3,553

C. Pension and Other Post-retirement Plans

Under Canadian GAAP, the Corporation disclosed, but did not recognize, its amortized gains and losses, its past service costs and its unamortized transitional obligation associated with pension and other post-retirement benefits. Under US GAAP, the Corporation has recognized its unfunded pension obligation as a liability. The unamortized gains and losses and past service costs are recognized in accumulated other comprehensive losses and the unamortized transitional obligation previously determined under Canadian GAAP is recognized in retained earnings.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Prepaid expense and other current assets	(381)	-
Non-current assets - Regulatory assets	1,406	15,808
Goodwill	-	(74)
Long-term investments and other assets	-	(381)
Deferred income taxes	(1,676)	(1,689)
Future employee obligations	7,563	21,481
Accumulated other comprehensive (loss) income	(3,590)	(3,599)
Accumulated deficit	(1,271)	(840)

D. Risk Management: Natural Gas Held in Storage

US GAAP requires inventory to be carried at the lower of cost and net realizable value. Under Canadian GAAP, AltaGas designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. As a result, proprietary natural gas held in storage was carried at fair value based on published market prices as at the balance sheets dates less costs to sell.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Inventory	(903)	1,228
Deferred income taxes	(255)	278
Accumulated deficit	(648)	950

E. Risk Management: De-designation of Cash Flow Hedges

Under Canadian GAAP the results of the joint venture ASTC were accounted for using proportionate consolidation. AltaGas hedged the power delivered by ASTC to the Alberta Power Pool. Under Canadian GAAP, hedge accounting was applied to those cash flow hedges. Under US GAAP, a forecasted transaction is eligible for designation as a hedged transaction in a cash flow hedge if the forecasted transaction is a transaction with a party external to the reporting entity and it presents an exposure to variations in cash flows for the hedged risk that could affect reported earnings. US GAAP specifically states specifically that “equity-method investments cannot be considered analogous to a consolidated subsidiary. Under the equity method of accounting, the investor generally records its share of the earnings or loss from the investment. In addition, the equity-method investment represents the investor's share of the investee's net assets”.

The cash flow hedges for the power delivered by ASTC have been de-designated and the after-taxes unrealized gains have been reversed from the statement of accumulated other comprehensive loss and recognized in earnings and accumulated deficit.

F. Debt Financing Costs

Under Canadian GAAP, debt financing costs were netted against long-term debt. Under US GAAP, debt financing costs are included in "other current assets" and "long-term investments and other assets" depending on the underlying terms of the related debts.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Prepaid expenses and other current assets	197	417
Long-term investments and other assets	9,273	12,407
Long-term debt	9,470	12,825

G. Income Tax on Preferred Share Dividends

Measurement
Under Canadian GAAP, the substantively enacted tax rate was used to measure the future tax asset offset to the Part VI.I tax. Under US GAAP, the enacted tax rate must be used.

The effect on the balance sheets of this GAAP difference is as follows:

As at ($ thousands)	January 1 2011	December 31 2011
Deferred income taxes	275	1,025
Accumulated deficit	(275)	(1,025)

Presentation
Under Canadian GAAP Part V, when preferred shares are classified as equity and dividends on preferred shares are charged to retained earnings, the related corporation tax is charged to retained earnings. Income tax reductions or recoveries as a result of the Part VI.I tax are also accounted for in the same manner as the Part VI.I tax that led to the reduction and receive the same accounting treatment as the dividends to the extent the income tax reductions or recovery arises in the same period as the Part VI.I tax.

Under US GAAP, Part VI.I tax income tax reductions or recoveries are included in income tax expense.

This resulted in no effect on the balance sheets as at January 1, 2011 and December 31, 2011.

Section II – Additional disclosures required under US GAAP

The following represents the effect of US GAAP adoption to the note disclosures required for annual financial statements that are not otherwise found in these interim consolidated financial statements or Canadian GAAP annual financial statements.

Financial Statement Effects of Rate Regulation

AltaGas accounts for certain transactions in accordance with applicable regulations enforced by AUC, BCUC and NSUARB, which may be different in the absence of rate regulation. This results in the creation of regulatory assets and liabilities.

As at January 1, 2011 and December 31, 2011, the effect on the note 'financial statement effects of rate regulation' is as follows:

As at January 1, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Regulatory assets - current				
Deferred cost of gas		2	-	2
		$ 2	-	$ 2
Regulatory assets - non-current				
Deferred regulatory costs		265	-	265
Pipeline rehabilitation costs		-	-	-
Future recovery of other retirement benefits	C	1,631	1,406	3,037
Deferred depreciation and amortization		5,479	-	5,479
Deferred income taxes		28,798	-	28,798
Revenue deficiency account		40,342	-	40,342
		$ 76,515	1,406	$ 77,921
Regulatory liabilities - current				
Deferred property taxes		51	-	51
Deferred cost of gas		825	-	825
Deferred regulatory costs		618	-	618
		1,494	-	1,494
Regulatory liabilities - non-current				
Future removal and site restoration costs		18,518	-	18,518
		$ 18,518	-	$ 18,518

As at December 31, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Regulatory assets - current						
Deferred cost of gas			5,141	-		5,141
		$	5,141	-	$	5,141
Regulatory assets - non-current						
Rate stabilization adjustment mechanism			126	-		126
Deferred regulatory costs			2,190	-		2,190
Pipeline rehabilitation costs			2,704	-		2,704
Future recovery of other retirement benefits	C		4,341	15,808		20,149
Deferred depreciation and amortization			9,180	-		9,180
Deferred income taxes			41,128	-		41,128
Revenue deficiency account			45,117	-		45,117
		$	104,786	15,808	$	120,594
Regulatory liabilities - current						
Deferred property taxes			94	-		94
Deferred cost of gas			56	-		56
Deferred regulatory costs			353	-		353
		$	503	-	$	503
Regulatory liabilities - non-current						
LNG Partners option fees deferral			3,021	-		3,021
West Fraser termination payment deferral			3,454	-		3,454
Future removal and site restoration costs			20,211	-		20,211
		$	26,686	-	$	26,686

Property, Plant, and Equipment

As a result of the US GAAP transition adjustments noted in Section I of the note, the net book value of property, plant and equipment decreased by $53.0 million as at January 1, 2011 and by $54.2 million as at December 31, 2011.

The restated continuity schedule of property, plant and equipment under US GAAP is as follows:

	January 1, 2011			December 31, 2011		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	$ 901,585	$ (124,956)	$ 776,629	$ 1,028,781	$ (148,924)	$ 879,857
FG&P assets	686,799	(222,201)	464,598	819,795	(255,136)	564,659
Energy services assets	1,344	(1,238)	106	1,453	(1,385)	68
Storage assets	-	-	-	-	-	-
Other assets	11,798	(8,357)	3,441	11,778	(9,174)	2,604
Power						
Capital lease	13,798	(8,760)	5,038	13,798	(10,117)	3,681
Power generation assets	370,217	(9,013)	361,204	536,914	(17,143)	519,771
Utilities	293,790	(3,033)	290,757	512,958	(16,025)	496,933
Corporate						
Other assets	26,988	(5,229)	21,759	21,478	(3,001)	18,477
	$ 2,306,319	$ (382,787)	$ 1,923,532	$ 2,946,955	$ (460,905)	$ 2,486,050

Intangible Assets

As a result of the US GAAP transition adjustments noted in Section I of the note, the net book value of intangible assets decreased by $60.0 million as at January 1, 2011, and by $55.2 million as at December 31, 2011.

The restated continuity schedule of intangible assets under US GAAP is as follows:

	January 1, 2011			December 31, 2011		
	Cost	amortization	Net book value	Cost	amortization	Net book value
Energy services and E&T arrangements and contracts	$ 57,798	$ (11,053)	$ 46,745	$ 57,798	$ (13,816)	$ 43,982
Electricity service agreement(1)	-	-	-	90,000	-	90,000
Energy services relationships	20,892	(6,708)	14,184	20,892	(8,101)	12,791
Computer software	38,066	(25,114)	12,952	36,750	(20,330)	16,420
Land rights	5,002	(1,412)	3,590	13,437	(1,505)	11,932
Franchises and consents	3,015	(463)	2,552	3,014	(623)	2,391
	$ 124,773	(44,750)	80,023	$ 221,891	(44,375)	$ 177,516

(1)The Electricity Service Agreement relates to a 60-year CPI Indexed Energy Purchase Agreement (EPA) not yet subject to amortization.

Goodwill

As at January 1 and December 31, 2011, the effect on goodwill is reflected with the following increases (decreases):

	Section I Notes	January 1, 2011	December 31, 2011
Under Canadian GAAP		$ 199,497	$ 258,092
Business combinations	A	23,175	23,175
Accounting for joint ventures	B	(70)	(70)
Pension and other post-retirement benefits	C	-	(74)
Under US GAAP		$ 222,602	$ 281,123

Long-term Investments and Other Assets

As at January 1, 2011 and December 31, 2011, the effect on long-term investments and other assets is reflected with the following increases (decreases):

As at January 1, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Investments in publicly-traded entities		$ 24,447	-	$ 24,447
Equity accounted investments in private entities	B	3,933	(3,933)	-
Accrued pension asset		1,703	-	1,703
Other	F	2,504	9,272	11,776
		32,587	5,339	37,926

As at December 31, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Investments in publicly-traded entities		$ 6,819	-	$ 6,819
Equity accounted investments in private entities	B	3,553	(3,553)	-
Accrued pension asset		5,057	(381)	4,676
Other	B & F	1,160	12,753	13,913
		16,589	8,819	25,408

Income Taxes

As at January 1, 2011 and December 31, 2011, the effect on the note 'income taxes' is reflected with the following increases (decreases):

As at January 1, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Income before income taxes - consolidated		$	102,989	27,051	$	130,040
Financial instruments - net	D & E		1,337	(28,158)		(26,821)
Income before financial instruments and income taxes			104,326	(1,107)		103,219
Income from AltaGas Income Trust distributed to unitholders			(76,146)	-		(76,146)
Income before income taxes - operating subsidiaries			28,180	(1,107)		27,073
Statutory income tax rate (%)			28.00	-		28.00
Expected taxes at statutory rates			7,890	(310)		7,580
Add (deduct) the tax effect of:						
Financial instruments			(632)	7,446		6,814
Rate reductions applied to deferred income tax liabilities	D & E		305	-		305
Permanent differences between accounting and tax basis of assets and liabilities	B		352	(106)		246
Non-taxable portion of capital gains (losses) on disposition of assets and investments			(277)	-		(277)
Rate adjustment	C		-	173		173
Taxable preferred shares	G		-	642		642
Other			225	(173)		52
Deferred income tax (recovery) on regulated assets			(5,255)	-		(5,255)
Prior year adjustment			(881)	-		(881)
			1,727	7,672		9,399
Income tax provision (recovery)						
Current			(222)	1,321		1,099
Deferred			1,949	6,351		8,300
		$	1,727	7,672	$	9,399
Effective income tax rate (%)			1.68	5.55		7.23

As at December 31, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Income before income taxes - consolidated		$	113,391	(379)	$	113,012
Financial instruments - net	D & E		8,337	687		9,024
Income before income taxes - operating subsidiaries			121,728	308		122,036
Statutory income tax rate (%)			26.50	-		26.50
Expected taxes at statutory rates			32,258	82		32,340
Add (deduct) the tax effect of:						
Financial instruments	D & E		(2,446)	(172)		(2,618)
Rate reductions applied to deferred income tax liabilities			(1,109)	-		(1,109)
Permanent differences between accounting and tax basis of assets and liabilities	B		682	(205)		477
Non-taxable portion of capital gains (losses) on disposition of assets and investments			319	-		319
Rate adjustment			(6,861)	-		(6,861)
Taxable preferred shares	G		-	1,750		1,750
Other			660	-		660
Deferred income tax (recovery) on regulated assets			(4,725)	-		(4,725)
Prior year adjustment			11	-		11
			18,789	1,455		20,244
Income tax provision (recovery)						
Current			175	3,877		4,052
Deferred			18,614	(2,422)		16,192
		$	18,789	1,455	$	20,244
Effective income tax rate (%)			16.57	1.34		17.91

The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between the tax basis and book carrying values on the Corporation's assets at enacted tax rates.

As at January 1, 2011 and December 31, 2011, deferred income taxes under US GAAP were composed of the following:

As at		January 1, 2011		December 31, 2011
Property, plant and equipment and Intangible assets	$	216,134	$	278,479
Regulatory assets		17,665		20,576
Deferred financing		(1,134)		(3,041)
Partnerships		12,994		8,448
Deferred compensation		(5,308)		(3,710)
Financial instruments		937		(2,444)
Non-capital losses		(15,249)		(33,509)
Preferred shares		275		1,025
Other		(275)		(42)
	$	226,039	$	265,782

Uncertain tax positions

Under Canadian GAAP, the Corporation recognized the benefit of an uncertain tax position when it was probable of being sustained.

Under US GAAP, the Corporation recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Management reviewed all open tax returns and determined that no provisions were required for uncertainty on income taxes.

Pension Plans and Retiree Benefits

The following restated table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans under US GAAP as at January 1, 2011 and December 31, 2011:

	Defined Benefit January 1, 2011	Post-Retirement Benefits January, 2011	Defined Benefit December 31, 2011	Post -Retirement Benefits December 31,2011
Accrued benefit obligation				
Balance, beginning of year	36,610	2,571	48,017	2,946
Assumed through acquisition	-	-	29,253	6,444
Actuarial loss	6,553	131	2,745	49
Current service cost	3,105	129	4,580	370
Member contributions	-	-	22	-
Interest cost	2,538	177	4,433	524
Benefits paid	(789)	(62)	(3,418)	(269)
Balance, end of year	$ 48,017	$ 2,946	$ 85,632	$ 10,064
Plan assets				
Fair value, beginning of year	28,688	-	33,687	-
Assumed through acquisition	-	-	23,139	1,184
Actual gain (loss) on plan assets	3,551	-	(2,463)	(24)
Employer contributions	2,366	-	6,188	825
Member contributions	99	-	124	-
Benefits paid	(789)	-	(3,418)	(269)
Actual plan expenses	(228)	-	(334)	-
Fair value, end of year	$ 33,687	$ -	$ 56,923	$ 1,716
Funded status	$ (14,330)	$ (2,946)	$ (28,709)	$ (8,348)
Accrued benefit obligation recognized in the financial statements	$ (14,330)	$ (2,946)	$ (28,709)	$ (8,348)

The following amounts were not recognized in the net periodic benefit cost and recorded in the other comprehensive losses:

	Defined Benefit January 1, 2011	Post-Retirement Benefits January, 2011	Defined Benefit December 31, 2011	Post -Retirement Benefits December 31,2011
Amounts included in other comprehensive income (loss)				
Transitional asset (obligation)	2,947)	129	(1,562)	(48)
Past service credit (cost)	-	(7)	77	-
Net actuarial gain (loss)	(2,110)	149	(3,516)	251
Total accumulated other comprehensive income (loss) on a pre-tax basis	(5,057)	271	(5,001)	203
Increase (decrease) by the amount included in deferred tax liabilities	1,264	(68)	1,250	(51)
Net amount in accumulated other comprehensive income (loss) after tax adjustment	$ (3,793)	$ 203	$ (3,751)	$ 152

The assets are invested under balanced fund mandates with a broad mix of Fixed income, Canadian equity and Foreign equity investments. The collective investment mixes for the plans are as follows as at January 1, 2011:

	Percentage of Plan Assets
Cash and short-term equivalents	4.05
Canadian equities	33.93
Foreign equities	27.85
Fixed income instruments	34.17
	100.00%

The collective investment mixes for the plans are as follows as at December 31, 2011:

	Percentage of Plan Assets
Cash and short-term equivalents	8.9
Canadian equities	31.64
Foreign equities	27.52
Fixed income instruments	31.93
	100.00%

Joint Ventures

Financial information for AltaGas' interest in joint venture arrangements under US GAAP is summarized in the tables below. The tables represent 100 percent of the investee financial information which AltaGas accounts for using the proportionate consolidation and equity accounting methods.

As at January 1, 2011		Proportionate Consolidation Method		Equity Method		Total
Revenues		156,668	$	94,232		250,900
Expenses		119,504		75,746		(195,250)
	$	37,164	$	18,486	$	55,650
Current assets		39,969		19,762		59,731
Property, plant and equipment		256,951		38,949		295,900
Intangible assets		17,619		59,919		77,538
Long-term investments and other assets		-		2		2
Current liabilities		(8,519)		(17,125)		(25,644)
Other long-term liabilities		(3,625)		(954)		(4,579)
	$	302,395	$	100,553	$	402,948
Operating activities		42,323		25,554		67,877
Investing activities		918		(11,035)		(10,117)
Financing activities		(29,693)		(13,683)		(43,376)
	$	13,548	$	836	$	14,384

As at December 31, 2011		Proportionate Consolidation Method		Equity Method		Total
Revenues		194,899		157,512		352,411
Expenses		131,305		120,928		(252,233)
	$	63,594	$	36,584	$	100,178
Current assets		48,858		15,793		64,651
Property, plant and equipment		260,411		33,823		294,234
Intangible assets		16,819		55,169		71,988
Long-term investments and other assets		-		2		2
Current liabilities		(15,590)		(13,311)		(28,901)
Other long-term liabilities		(4,951)		(843)		(5,794)
	$	305,547	$	90,633	$	396,180
Operating activities		60,807		43,260		104,067
Investing activities		(11,469)		(17,301)		(28,770)
Financing activities		(45,100)		(26,736)		(71,836)
	$	4,238	$	(777)	$	3,461

Supplementary Quarterly Financial Information
(unaudited)

($ millions unless otherwise indicated)	**Q1-12**	Q4-11	Q3-11	Q2-11	Q1-11
FINANCIAL HIGHLIGHTS[1]					
Net Revenue[2]					
Gas	**87.5**	92.6	77.2	80.6	87.5
Power	**34.6**	31.7	27.8	21.4	32.1
Utilities	**43.3**	24.7	15.9	18.9	26.1
Corporate	**3.0**	8.3	(4.0)	(12.2)	(9.9)
Intersegment Elimination	**(0.9)**	(0.4)	(0.4)	(1.5)	0.3
	167.5	156.9	116.5	107.2	136.1
EBITDA[2]					
Gas	**44.7**	45.9	32.7	39.3	44.3
Power	**29.5**	25.0	24.1	18.1	29.2
Utilities	**24.4**	10.1	5.9	7.9	14.7
Corporate	**(6.0)**	(8.6)	(8.0)	(10.6)	(9.2)
	92.6	72.4	54.7	54.7	79.0
Operating Income (Loss)[2]					
Gas	**30.1**	31.7	18.4	25.2	30.2
Power	**26.9**	22.4	21.5	15.5	26.6
Utilities	**19.4**	4.7	2.9	4.9	11.7
Corporate	**(6.8)**	(9.6)	(9.3)	(11.4)	(10.2)
	69.6	49.2	33.5	34.2	58.3

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

(2) *Non-GAAP financial measure.*

Supplementary Quarterly Operating Information

(unaudited)

	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11
OPERATING HIGHLIGHTS					
GAS					
E&T					
Extraction inlet gas processed (Mmcf/d)(1)	**944**	923	871	828	909
Extraction volumes (Bbls/d)(1)	**45,186**	43,454	39,781	38,843	42,153
Frac spread - realized ($/Bbl)(1)(3)	**34.11**	42.00	22.95	36.65	32.45
Frac spread - average spot price ($/Bbl)(1)(4)	**40.42**	46.59	42.15	41.27	40.91
FG&P					
Processing Throughput (gross Mmcf/d)(1)	**400**	391	404	391	375
Energy Services					
Average volumes transacted (GJ/d)(1)	**376,071**	357,105	340,396	377,967	403,777
POWER					
Volume of power sold (GWh)(1)	**816**	774	760	729	740
Average price realized on sale of power ($/MWh)(1)	**72.56**	79.14	80.67	64.26	78.76
Alberta Power Pool average spot price ($/MWh)(1)	**60.12**	76.42	94.70	52.12	83.33
UTILITIES					
Natural gas deliveries - end-use (PJ)(5)	**10.8**	21.8	2.3	3.7	9.3
Natural gas deliveries - transportation (PJ)(5)	**2.0**	4.6	1.1	1.2	1.3
Service sites(2)	**115,623**	115,932	75,126	74,823	75,055
Degree day variance from normal - AUI (%) (6)	**(11.5)**	-	(33.7)	0.5	23.6
Degree day variance from normal - Heritage Gas (%) (6)	**(8.6)**	(12.7)	(20.9)	19.7	8.0

(1) Average for the period.

(2) As at period end.

(3) Excludes natural gas liquids pipeline volumes.

(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.

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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