We're in a good place

AltaGas Annual Report | 2010

2010 Financial Highlights

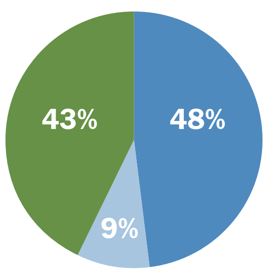
$ millions except as indicated	2010	2009	2008	2007	2006
Revenue	**1,354.1**	1,268.3	1,816.8	1,428.4	1,362.6
Net revenue [1]	**485.5**	456.6	476.5	324.0	318.9
EBITDA [1]	**243.8**	251.5	258.7	175.2	174.5
EBITDA adjusted for mark-to-market accounting [1]	**249.5**	242.0	247.7	174.1	174.5
Operating income [1]	**151.8**	174.3	188.0	126.6	126.7
Operating income adjusted for mark-to-market accounting [1]	**157.5**	164.8	177.0	125.5	126.7
Net income applicable to common shares	**97.2**	141.3	163.6	108.8	114.5
Net income applicable to common shares adjusted for mark-to-market accounting [1]	**101.7**	132.7	158.0	109.3	114.5
Total assets	**2,751.7**	2,628.9	2,132.3	1,172.7	1,109.6
Total debt	**904.5**	1,014.6	565.3	220.8	265.5
Debt as a percent of total capitalization (%)	**42.8**	49.2	37.8	27.4	33.4
Funds from operations [1]	**195.0**	202.3	216.8	162.9	161.7
Distributions declared	**87.0**	170.2	147.1	118.6	110.8
Dividends declared	**54.1**	–	–	–	–
$ per basic share					
EBITDA adjusted for mark-to-market accounting [1]	**3.06**	3.08	3.60	3.03	3.14
Net income applicable to common shares	**1.19**	1.80	2.38	1.90	2.06
Net income applicable to common shares adjusted for mark-to-market accounting	**1.25**	1.69	2.30	1.90	2.06
Funds from operations [1]	**2.39**	2.58	3.15	2.84	2.92
Distributions declared	**1.08**	2.16	2.125	2.065	1.995
Dividends declared	**0.66**	–	–	–	–

1 Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of the MD&A.

With a strong balance sheet, we have the financial flexibility to fund our committed capital program.

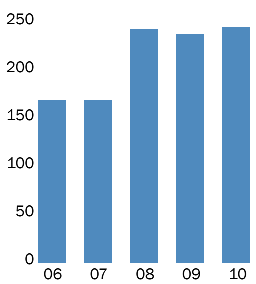
Capital structure

EQUITY
PREFERRED SHARES
DEBT



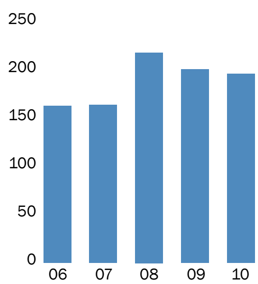
EBITDA adjusted for mark-to-market accounting

$ millions



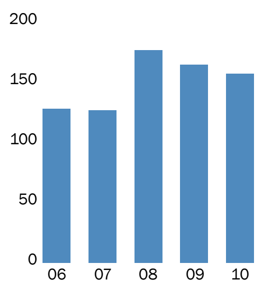
Funds from operations

$ millions



Operating income adjusted for mark-to-market accounting

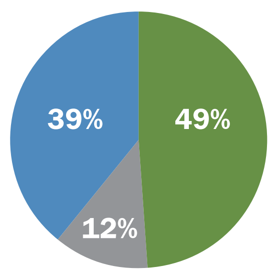
$ millions

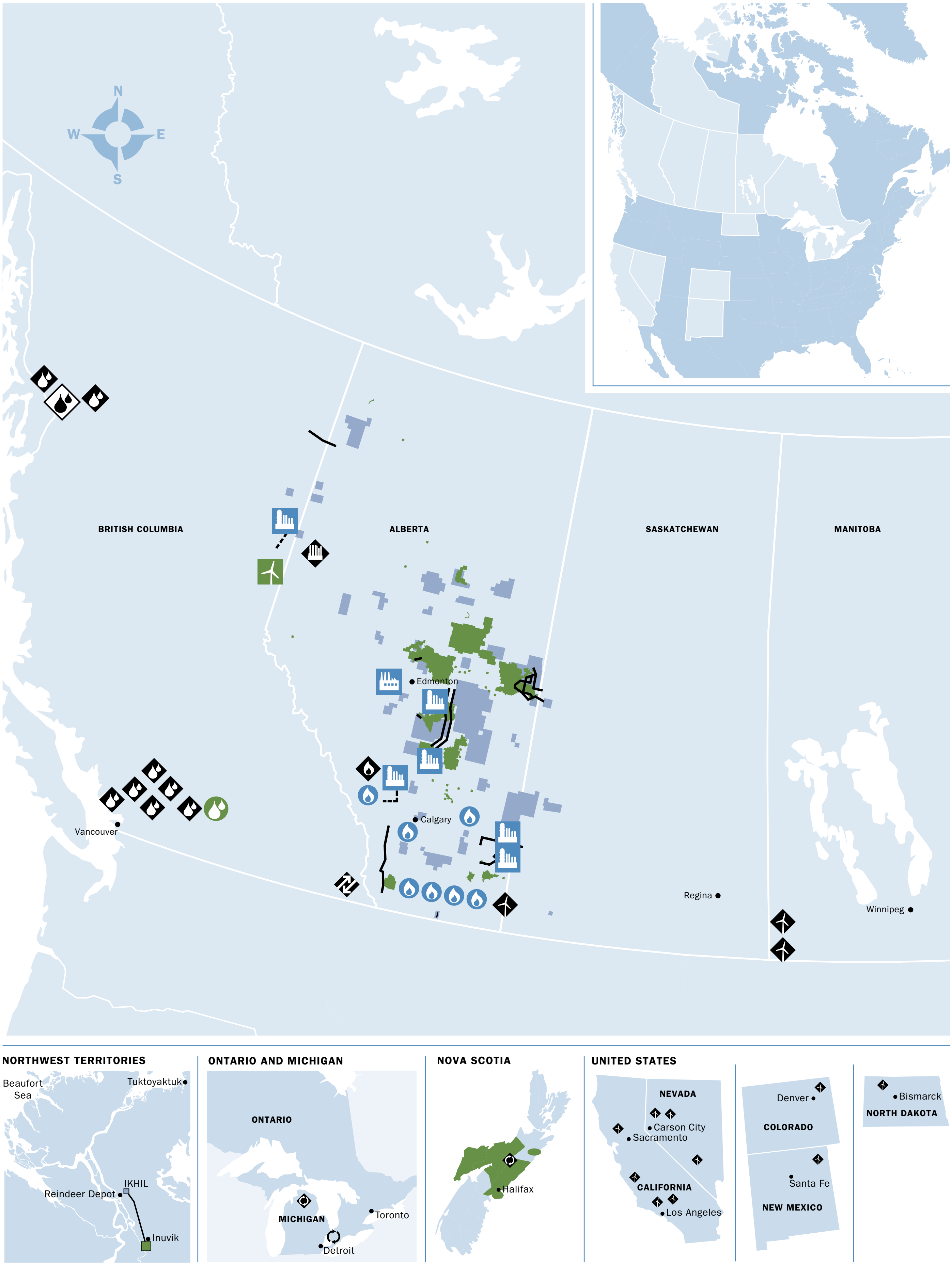


We generate superior economic returns by investing in low-risk, long-life energy assets.

Operating income

GAS
POWER
UTILITY




N
W
E
S
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
Edmonton
Calgary
Vancouver
Regina
Winnipeg
NORTHWEST TERRITORIES
Beaufort Sea
Tuktoyaktuk
IKHIL
Reindeer Depot
Inuvik
ONTARIO AND MICHIGAN
ONTARIO
MICHIGAN
Toronto
Detroit
NOVA SCOTIA
Halifax
UNITED STATES
NEVADA
Carson City
Sacramento
CALIFORNIA
Los Angeles
Denver
COLORADO
Santa Fe
NEW MEXICO
Bismarck
NORTH DAKOTA

We've built a portfolio of long-life, high-quality assets that provide a platform for future growth.

Gas Business

Extraction Plants

We hold interests in six of the 10 extraction plants in Canada. These plants process natural gas to recover residual ethane and natural gas liquids (NGLs).

Pipelines

We own and operate eight transmission pipelines that transport 554 million cubic feet per day of natural gas and 152,000 barrels per day of NGLs. The pipelines connect producers to markets throughout North America.

Pipelines Under Construction

Additional pipelines to the Harmattan and Younger extraction facilities are under construction.

Field Gathering & Processing Area

We operate more than 70 facilities in 30 operating areas across western Canada that process raw natural gas to remove impurities, and in some cases, to extract higher value-added NGLs. Our network of 6,500 km of gathering and sales lines provides producers in the Western Canada Sedimentary Basin (WCSB) with quick access to North American markets.

Gas Plants Under Development

The Gordondale Gas Plant is currently under development in northwest Alberta.

Storage Facility

We have a 50 percent interest in a gas storage asset in Sarnia, Ontario, with 5.3 Bcf of natural gas storage capacity.

Storage Facilities Under Development

Further storage is under development in Michigan and Nova Scotia.

Energy Services

We provide gas procurement, management and optimization services by contracting supply and shrinkage gas for extraction facilities. We contract and resell capacity on the transmission pipelines and provide gas control services to balance gas flows. We also store and market gas for producers and end users, and procure energy for large industrial and utility customers across Canada.

Power Business

Coal-fired Power Generation

Our 50 percent ownership interest in the Sundance B Power Purchase Arrangements (PPAs) gives us control of 353 MW of low-cost, base-load power in Alberta.

Gas-fired Power Generation

We have 54 MW of gas-fired generation capacity in Alberta through a capital lease and directly owned, including the recently commissioned 15 MW Harmattan cogeneration facility. The peaking plants have quick ramp-up capabilities, enabling them to generate revenue from the sale of energy and ancillary services, while cogeneration provides the steam required to process gas and electricity for on-site consumption and for the electrical grid.

Gas-fired Power Generation Under Development

More gas-fired power generation is under development. The second phase of the Harmattan cogeneration facility will provide an additional 15 MW of power.

Waste Heat Recovery Under Development

We are adding a new type of power to our portfolio, with a 60 percent interest in the 6 MW Crowsnest Pass waste heat recovery power plant in Sparwood, British Columbia. A 20-year Electricity Purchase Agreement (EPA) is in place with BC Hydro.

Wind Power Generation

The 102 MW Bear Mountain Wind Park near Dawson Creek, British Columbia, delivers power to BC Hydro under a 25-year EPA.

Wind Power Generation Under Development

We have 1,500 MW of wind power projects under various stages of development in western Canada and the northern and western United States.

Hydro Power Generation

We have an effective interest of 25 percent in a 7 MW, run-of-river hydroelectric power generation facility in British Columbia.

Hydro Power Generation Under Construction

The Forrest Kerr run-of-river hydroelectric project (195 MW) is under construction and will provide power to BC Hydro under a 60-year EPA.

Hydro Power Generation Under Development

There are 205 MW of hydro power generation projects under development in British Columbia.

Utility Business

Gas Distribution

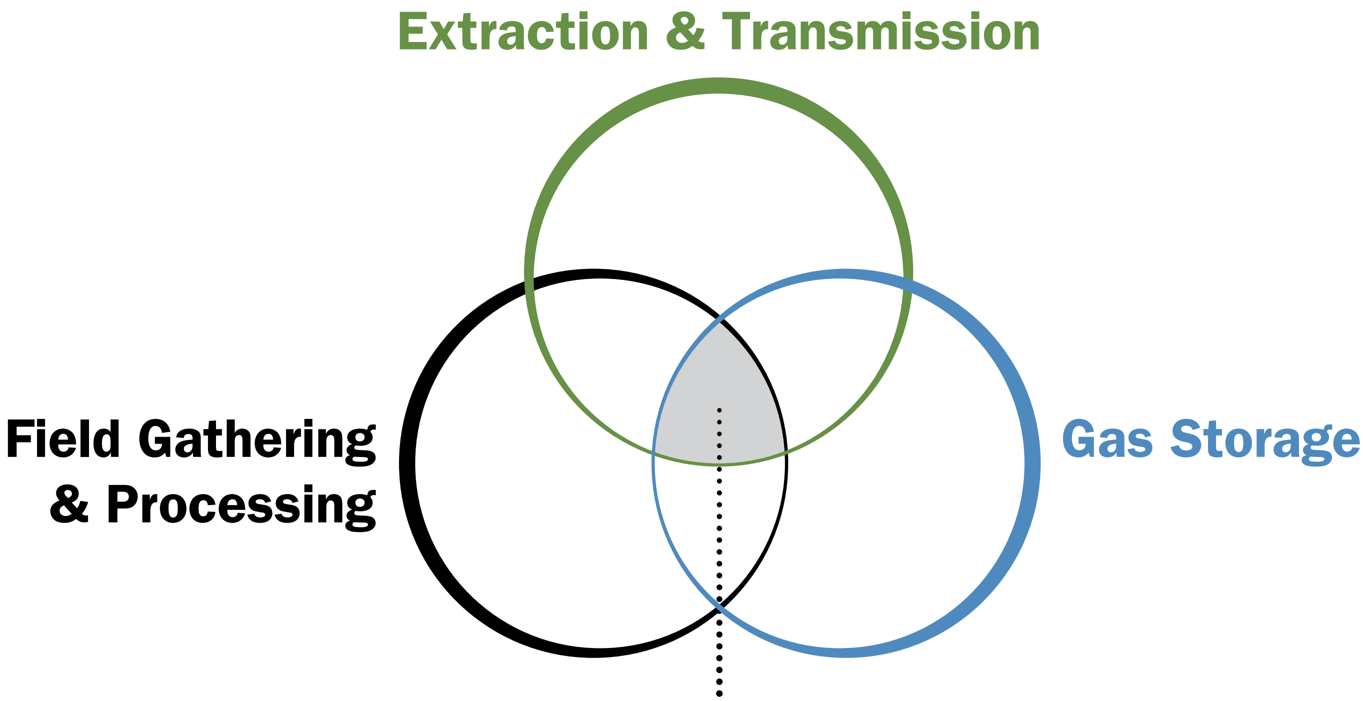
Our Utility business is comprised of regulated natural gas distribution systems in Alberta (AltaGas Utilities Inc.), Nova Scotia (Heritage Gas Ltd.), and the Northwest Territories (Inuvik Gas Ltd. and Ikhil Joint Venture).

AltaGas Utilities Inc. (AUI) and Heritage Gas operate in marketplaces where they are allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on capital from the franchise capital investment base.

In fact, we're in a lot of good places

AltaGas' vision is to be a leading North American energy infrastructure company. Our focus is Canada and the northern and western United States.

The Report

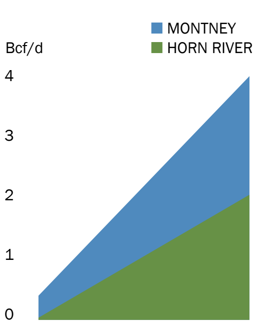


AltaGas

By providing a spectrum of midstream energy services, we're able to mitigate risk and capture economies of scale.

We're capitalizing on the growing unconventional natural gas supply in the WCSB.

Expected growth



Our $130 million Harmattan Co-stream Project is enhancing value to the petrochemical industry in Alberta. The project will bring rich, sweet natural gas from the west leg of the Alberta system to be processed using existing spare capacity.

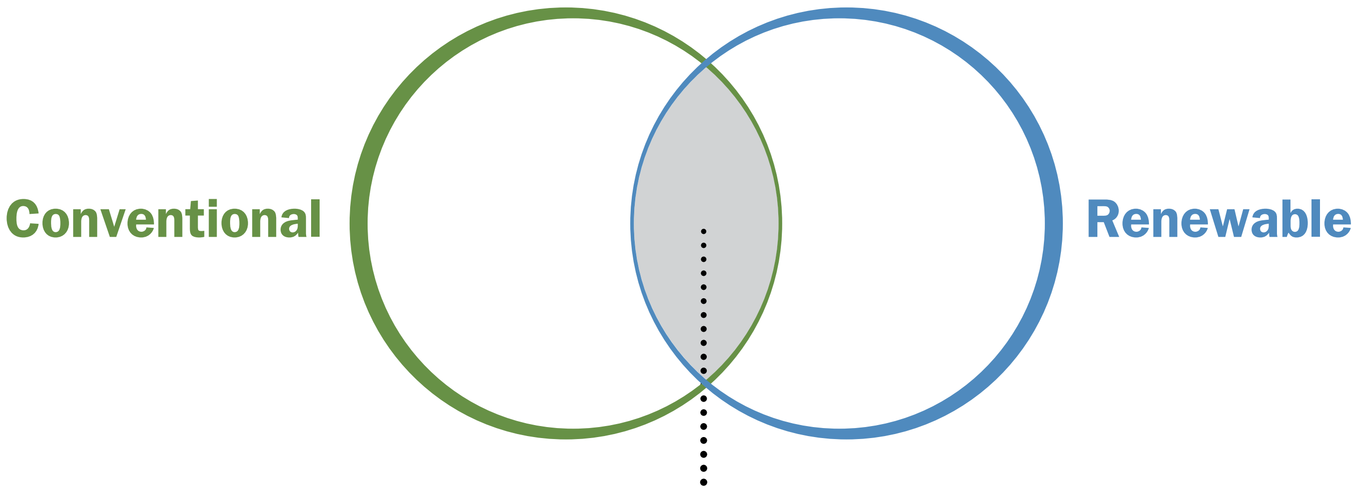
The Gordondale gas processing facility is an exceptional gas infrastructure project located in the Montney resource area that will provide long-term, stable cash flows. The $235 million plant will be equipped with liquids extraction facilities to capture the natural gas liquids value for our customers.

Natural gas is a good place to be

We're building new assets and increasing volumes where gas supply is growing, while stabilizing earnings with fixed-fee and cost-of-service contracts.

We're meeting producer demand by expanding, consolidating and building processing facilities including an expansion at our Pouce Coupe facility located in the Montney resource area.

We entered into an agreement to acquire the Groundbirch sour gas plant in the Montney resource area in return for a dedicated take-or-pay processing obligation.



AltaGas

By pursuing a variety of power sources,
we can continue to be a reliable power provider
while filling the growing demand for clean energy.

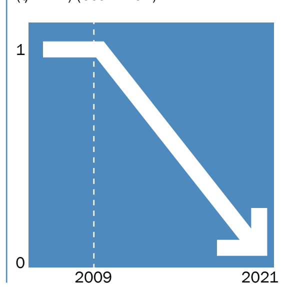
The Sundance B facility is among the lowest cost producers of power in Alberta. Our PPAs uniquely position us to maintain profitable operations during difficult economic conditions.

54 MW of gas-fired power generation in Alberta adds fuel diversity to our portfolio, including the newly commissioned 15 MW cogeneration facility at Harmattan completed on time and under budget.

Clean sources of power, such as wind, run-of-river hydroelectricity, geothermal and gas-fired generation.

Power business emissions intensity target

Emissions intensity (t/MWh) (Coal=1.04)

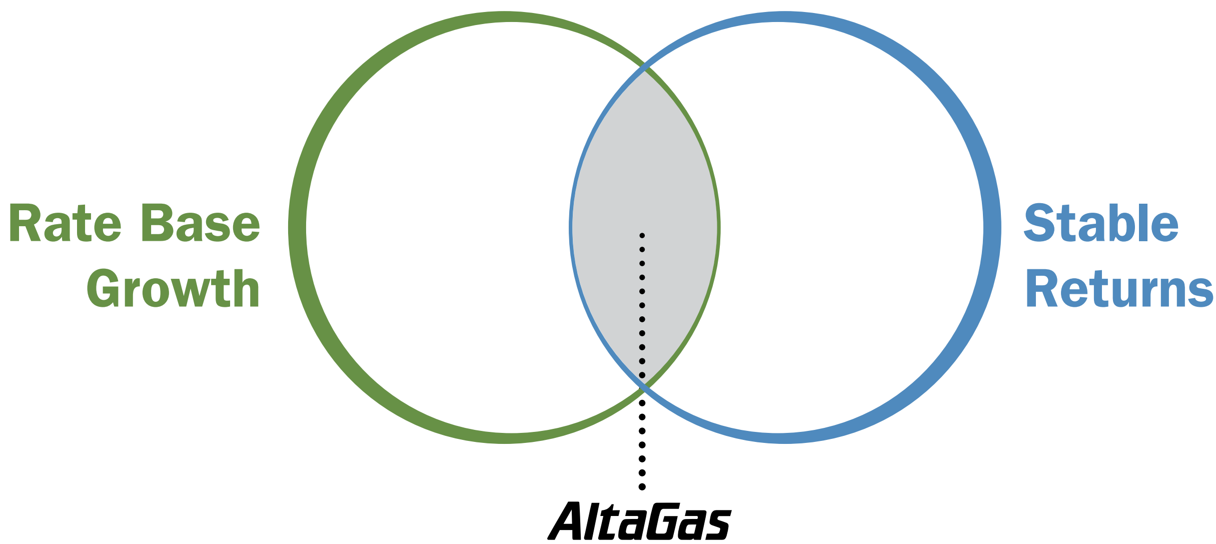


Power generation is a good place to be

We're combining base-load power with long-life, contracted, clean and renewable power, reducing our carbon footprint and delivering stable and growing earnings.

The Bear Mountain Wind Park completed its first full year of operations. Bear Mountain is backstopped by a 25-year EPA with BC Hydro.

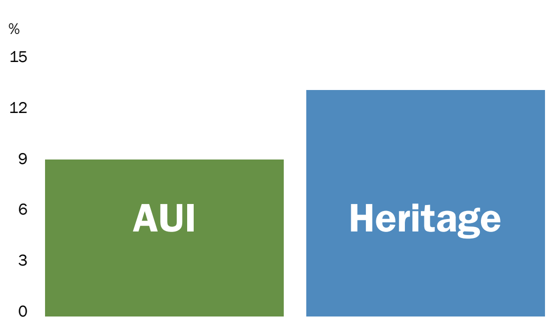
We made significant progress on growing our renewable power platform with the signing of a 60-year EPA with BC Hydro and associated long-term arrangements with the First Nations in support of the Forrest Kerr 195 MW run-of-river hydroelectric project. Base camp construction is complete, with construction activities continuing until mid-2014 on the estimated $700 million project.



Our rate regulated gas distribution infrastructure generates stable earnings growth through safe and reliable service to a growing customer base.

We continued to deliver stable returns in 2010.

Regulated return on equity for 2010



Offering clean natural gas through 64 km of new pipe to Fairview, Clayton Park, Bayer's Lake and Bedford in Nova Scotia. This expansion is expected to bring Heritage Gas 1,100 new customers.

Utilities are a good place to be

We're growing our regulated asset base while providing stable and predictable cash flows.

We're investing in the long-term reliability and efficiency of AUI's gas delivery systems. We completed the first year of a 20-year system rejuvenation program.

In 2010, we delivered natural gas to more than 74,000 customers, providing service to nearly 2,000 more customers than the year prior.

Our rate base grew 15 percent in 2010 and is forecasted to grow by 17 percent in 2011.

15%
rate base growth

AltaGas is a good place to be

David W. Cornhill
Chairman and Chief Executive Officer

LETTER TO SHAREHOLDERS

2010 was a solid year, and the future looks even brighter. We are investing in diversified energy infrastructure that will continue to provide long-term growth, cash flow and solid returns. We are well on our way to doubling EBITDA by 2016. Every aspect of our business is positioned for success.

We are just 18 months into our five-year, $2 billion growth plan. To date, we have $1.4 billion in capital projects under construction, $235 million awaiting regulatory approval and $500 million in high-grade development opportunities. Our goals are becoming a reality.

We are in a good place financially, with a strong balance sheet and ample liquidity to finance our growth over the next several years. We completed $1.5 billion in finance initiatives last year, including our first issuance of preferred shares. We converted to a dividend-paying corporation and provided our investors with a dividend at the high end of the range we proposed last year, proving once again to be a valuable long-term investment proposition.

With all this in mind, we are now ready for the next phase of growth. We have strengthened our team by adding new people. We are developing our team to take the Company into the future.

As part of this we have reorganized into three businesses to allow senior management to better oversee their business and growth opportunities.

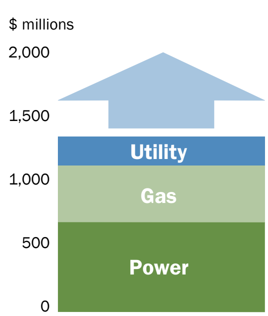
Gas Highlights

The past year has been a successful one. We expanded, consolidated, built and redeployed processing facilities to meet producer demand in active drilling areas of the WCSB.

In November, Encana committed to a long-term gathering and processing agreement that will supply natural gas to our new Gordondale deep-cut processing facility. AltaGas shareholders will benefit from this 120 Mmcf/d natural gas processing facility for years to come.

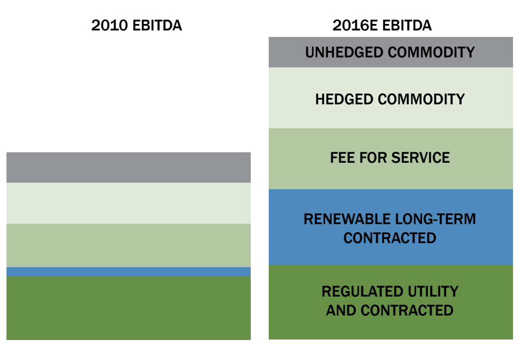
We set a goal to create $2 billion in organic growth by 2016. We have $1.4 billion committed.

2010 progress report



We will grow earnings by adding highly contracted, long-life infrastructure while decreasing our overall commodity exposure.

Growth and diversification strategy at work



We balance income and growth, ensuring stable and growing dividends along with capital appreciation.

Dividend set at $1.32 per share in 2010

In December, we were pleased to receive regulatory approval to proceed with our Harmattan Co-stream Project. This project will increase throughput at the Harmattan extraction facility and add extraction options on the west leg of the Alberta natural gas transmission system.

Looking ahead, our growth strategy for the Gas business is to expand our already significant presence in locations with emerging supplies of unconventional natural gas. This includes areas such as the Montney resource area in northeast British Columbia and tight gas plays along the Alberta Rockies.

We anticipate additional opportunities to increase processing volumes near our existing assets by tying in new wells and acquiring or building natural gas gathering, processing and transmission infrastructure. We will grow the Gas business and achieve even stronger results for our shareholders going forward. Our Gas business is in a good place.

Power Highlights

We had an exciting year in the power business. In May, we signed a 60-year EPA with BC Hydro and reached an agreement with First Nations for our 195 MW Forrest Kerr run-of-river hydroelectric power generation project.

We are pleased to have a strong partnership with the Tahltan Nation and we continue to work closely with them to advance this project. It will not only provide continued employment for the Tahltan people, but will provide enough electricity for approximately 70,000 homes in British Columbia, and offset more than 450,000 tonnes of greenhouse gas equivalents annually. In 2011, we will be working hard to obtain similar agreements to begin construction on the two sister hydroelectric projects near Forrest Kerr.

Bear Mountain Wind Park completed its first full year of operations, adding to our earnings in 2010 and it is just the beginning of our plan to pursue more wind projects to add to our power portfolio.

The demand for clean power is always increasing, and we have many renewable projects under development to help us meet it. As we grow our renewable power portfolio, we reduce our emissions intensity and continue to be part of the climate change solution.

Our renewable power generation business will undergo dramatic growth in the next few years. We continue to look to the future and turn ideas into reality as we increase our portfolio of clean energy assets to complement our profitable conventional power business in Alberta. Our Power business is in a good place.

Utility Highlights

We provide natural gas to over 74,000 residential and commercial customers in Alberta, Nova Scotia and Inuvik.

It is a safe and reliable way to keep their homes heated, their lights on and their businesses operating efficiently.

In Alberta, AltaGas Utilities Inc. completed the first year of the 20-year system rejuvenation program that will ensure reliable and efficient long-term gas delivery, and will maintain public and worker safety.

In Nova Scotia, Heritage Gas has a five-year expansion project underway. This project will install 64 km of pipe to serve 1,100 new customers in the Fairview, Clayton Park and Bedford regions of the Halifax Regional Municipality.

In 2010, our rate base grew by 15 percent and it is forecasted to grow another 17 percent in 2011.

Our utilities add a stable, growing source of cash flows and earnings, and strengthens our business risk profile. Our Utility business is in a good place.

Looking forward

Financial discipline is the cornerstone of AltaGas' strategy.

Ensuring we have sufficient liquidity and flexibility to meet our capital requirements, at the lowest possible cost, is a key element in meeting our growth objectives.

In 2011, we will continue to improve the performance of our existing businesses by controlling costs and capitalizing on the strategic location of our current assets. We will also continue to pursue opportunities that add low-risk, high-quality assets that create, move and hold energy and we will do this in a safe and reliable manner.

Safety is our number one priority. We have strict safety and environment management policies and procedures in place that have allowed us to exceed our targets this year. Furthermore, the 2010 external auditors awarded us with our highest scores for both safety and environmental audits in company history. Our goal is to advance our performance year-over-year and I am pleased with these results.

AltaGas is proud to be a part of the communities where we live, work and serve. Our employees have strong ties to the community and it shows through their generous contributions to community initiatives in health and social services, education and the arts.

The success achieved in 2010 and the growth planned for 2011 and beyond is due to the dedication of the 960 people that make up our workforce. I would like to thank you for all your hard work. Your continued enthusiasm and integrity is what makes AltaGas a great company and a great place to work.

The long-term success of AltaGas can also be attributed to our steadfast commitment to our core values. Since our inception, in addition to our focus on safety and environment and being financially astute, we have been Trailblazers, not afraid to be different or to challenge the industry status quo. Examples of this include our roots as the first midstream company in Canada and the development of new green-field natural gas distribution businesses, such as Heritage and Inuvik Gas. From the beginning, we have successfully focused on the big picture, attracted exceptionally talented and intelligent employees who are experts in their field and who act in a manner that is decisive, seizing available opportunities to create value. We know the importance of customers to the sustainability of our company and continuously strive to communicate effectively and appropriately with our many stakeholders.

Among the people who contribute to AltaGas' success are those who serve on the Board of Directors. Denis Fonteyne is retiring from the Board of Directors in April 2011 after more than 12 years of service to AltaGas. Denis served as Chair of the Environment, Occupational Health and Safety Committee from 2001 to 2010 and provided guidance throughout the growth of the organization. I would like to extend my deepest gratitude to Denis for his dedicated service.

We are in a good place. As we continue to grow, our shareholders will benefit from a business that is more diversified, more stable and more prosperous. The best is yet to come.

David W. Cornhill
Chairman and Chief Executive Officer
March 7, 2011

EXECUTING OUR STRATEGY IN 2010

	Optimize, Grow and Diversify Energy Infrastructure	What We've Accomplished This Year
POWER BUSINESS	**Forrest Kerr**	• Signed a 60-year inflation indexed EPA with BC Hydro in May for the 195 MW run-of-river project. • Expected to have a capital cost of $700 million and is expected in-service mid-2014.
POWER BUSINESS	**Harmattan Cogeneration**	• Completed the construction and commissioned a 15 MW gas-fired cogeneration facility at the Harmattan Complex in Q4 2010.
POWER BUSINESS	**McLymont Creek, Volcano Creek**	• Progressed negotiations with the Tahltan Nation, the Government of British Columbia and BC Hydro.
GAS BUSINESS	**Gordondale**	• Secured a long-term agreement with Encana to construct a $235 million, 120 Mmcf/d gas processing facility and an associated gas gathering system and deep-cut facility in the Gordondale area of the Montney resource play. • Expected in-service Q4 2012.
GAS BUSINESS	**Groundbirch**	• Entered into an agreement to acquire the 28 Mmcf/d Groundbirch sour gas plant in northeast British Columbia. Under the agreement, AltaGas invested approximately $28 million to construct the gas plant and related infrastructure in return for 100 percent ownership of the gas plant and a dedicated take-or-pay processing obligation.
GAS BUSINESS	**Harmattan Co-Stream**	• Received regulatory approval in December to pursue a $130 million co-stream project. • Signed a contract with Nova Chemicals for a 20-year, full cost-of-service agreement. • Expected in-service Q1 2012.
GAS BUSINESS	**Alton Storage**	• Acquired Landis Energy Corporation in March furthering the growth of the natural gas storage business in Atlantic Canada.
GAS BUSINESS	**Pouce Coupe, Ante Creek, Acme**	• Completed plant expansions at Pouce Coupe, Ante Creek and Acme processing facilities adding 32 Mmcf/d in capacity.
UTILITY BUSINESS	**Heritage Gas**	• Completed a $19 million project to Fairview, Clayton Park, Bayer's Lake and Bedford in Nova Scotia, during 2010. The expansion added 34 km of new pipelines to the natural gas distribution system and provides the foundation for further expansion into growing communities over the next several years.
UTILITY BUSINESS	**AUI and Heritage Gas**	• Increased rate base by 15 percent in 2010.

Maintain Financial Strength and Flexibility

CORPORATE		What We've Accomplished This Year
	Conversion to a Corporation	• Reorganized into a dividend-paying corporation. • Monthly dividend set at the high-end of the guidance range; $1.32 per share annualized.
	Credit Facilities	• $600 million syndicated credit facility with an accordion feature for another $200 million. • $200 million AltaGas Utility Group Inc. (AUGI) credit facility.
	Medium Term Notes (MTNs)	• $175 million MTNs issued in November, carrying a coupon rate of 4.6 percent, maturing January 15, 2018. • Issued $200 million MTNs in March, carrying a coupon rate of 5.49 percent, maturing March 27, 2017.
	Preferred Shares	• Offered 8,000,000 cumulative redeemable five-year rate-reset preferred shares in August, resulting in gross proceeds of $200 million and a strong balance sheet of a debt-to-total capitalization of 42.8 percent at December 31, 2010.

Develop Organizational Capability

CORPORATE		What We've Accomplished This Year
	Aboriginal Relations Policy	• Started developing an Aboriginal Relations Policy with the aboriginal communities with which it operates.
	Hired Construction Expertise	• Hired major projects teams for Gas and Power. • Led by experienced executives. • Engaged leading engineering firms.
	Internal Management Structure	• Completed an internal organization that established three divisional presidents to lead the Gas, Power and Utility businesses with full accountability for their profitability, working capital management and capital deployment.
	Project Management Framework	• Sponsored 25 employees to complete their project management certification in 2010 and will continue to follow project management methodologies. • Developed project management dashboards. • Developed cost control and reporting framework.
	Safety and Environmental Management	• Exceeded 2010 safety targets. • Achieved our highest-ever external audit scores for safety and environment.

CORPORATE GOVERNANCE

David W. Cornhill
Chairman and Chief Executive Officer

Member of the EOHSC

Myron F. Kanik
Lead Director

Independent director; Chair of the GC and Member of the HRCC

Allan L. Edgeworth
Director

Independent director; Member of the AC Chair of the EOHSC

Hugh A. Fergusson
Director

Independent director; Member of the AC and HRCC

Daryl H. Gilbert
Director

Independent director; Member of the AC and Chair of the HRCC

Robert B. Hodgins
Director

Independent director; Chair of the AC and Member of the GC

David F. Mackie
Director

Independent director; Member of the GC and HRCC

Neil McCrank
Director

Independent director; Member of the GC and EOHSC

The members of the Board of Directors of AltaGas Ltd. ("AltaGas") are elected by the shareholders to manage, or supervise the management of, its business and affairs. It is our responsibility to ensure that the interests of shareholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for the stewardship of AltaGas, and developed standards and procedures for its operations that meet a high standard of governance. We regularly review AltaGas' activities, with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that shareholders expect. We are committed to continuously meeting those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate AltaGas' goals and strategy to shareholders. The meeting offers shareholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase shareholder value and grow AltaGas. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting either in person in Calgary or through the live webcast that can be viewed at www.altagas.ca.

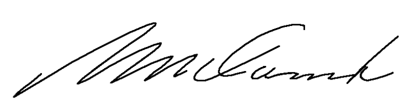
The annual meeting will be held at 3:00 p.m. MDT
on Wednesday, April 20, 2011 at
The Petroleum Club, Devonian Room,
319 – 5th Avenue S.W., Calgary, Alberta.

Denis C. Fonteyne
Director

Independent director; Member of the EOHSC and Member of the HRCC

The Board of Directors would like to express its thanks to Denis Fonteyne for more than twelve years of service as a Director of AltaGas. Denis, who is retiring from the Board of Directors upon conclusion of the annual meeting, joined the Board of Directors of the then AltaGas Services Inc. in September 1998. Denis brought a wealth of business knowledge and experience to AltaGas' Board from a career of more than 40 years in the oil and gas industry, where he held a number of senior executive positions. We thank Denis for his support, advice and dedication during his tenure with the Board of Directors.

On behalf of the Board of Directors:



Myron F. Kanik
Lead Director

AltaGas is committed to a high standard of governance, in the belief that it improves performance and benefits all shareholders. The following is a summary of AltaGas' Governance Practices. A more detailed description can be found in AltaGas' Management Information Circular filed on the SEDAR system at www.sedar.com.

STATEMENT OF GOVERNANCE PRACTICES

Mandate of the Board of Directors

The Board of Directors exercises responsibility for the management and supervision of the affairs of AltaGas. This includes the appointment and monitoring of the Chief Executive Officer, the appointment of other senior officers, and the approval of their compensation.

The Board of Directors also reviews and approves the annual strategic plan, which includes key objectives, quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks.

The Board of Directors also establishes a succession plan that includes the appointment, training and monitoring of senior management.

The independent Directors of AltaGas meet in the absence of management and non-independent Directors at each meeting of the Board of Directors.

Composition of the Board of Directors

David W. Cornhill, Chairman and Chief Executive Officer of AltaGas, is the only member of the Board of Directors who is also a member of management and considered not to be independent.

Committees of the Board of Directors

The Board has four standing committees: Governance (GC); Audit (AC); Environment, Occupational Health and Safety (EOHSC); and Human Resources and Compensation (HRCC). The GC, AC and HRCC are composed exclusively of non-management, independent directors. The EOHSC includes a majority of independent, non-management directors, as well as the Chairman and Chief Executive Officer of AltaGas. Each of the committees has a mandate that prescribes its composition and responsibilities approved by the Board of Directors.

Governance Committee

The GC reviews Board performance and provides recommendations for improvement with respect to all aspects of governance. The GC identifies and recommends individuals qualified to become members of the Board of Directors. It reviews and recommends compensation for Directors and, on an annual basis, formally assesses the effectiveness of the Committees and the Board of Directors. The GC is also responsible for the orientation and education of new Board members and continuing development of existing members.

The Chair of the Governance Committee is Myron F. Kanik, an energy industry consultant.

Audit Committee

The AC consists of four independent and financially literate Directors who oversee AltaGas' financial reporting process. It reviews and provides recommendations to the Board of Directors on annual and interim financial statements, and examines the adequacy of its risk management processes and internal control system for financial reporting and disclosure.

The AC approves the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every meeting, the AC has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the Audit Committee is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada Pipelines Limited.

Environment, Occupational Health and Safety Committee

The EOHSC is responsible for reviewing, reporting and making recommendations to the Board of Directors on AltaGas' policies and procedures with respect to the environment and occupational health and safety.

AltaGas is committed to being a steward of the environment and to the health and safety of its employees.

The Chair of the Environment, Occupational Health and Safety Committee is Allan L. Edgeworth, an energy industry consultant and former President and Chief Executive Officer of Alliance Pipeline Ltd.

Human Resources and Compensation Committee

The HRCC reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer, and the appointment and compensation of senior corporate officers. It also reviews succession plans, the compensation policy for all other employees and the approval of all grants of share options.

AltaGas is committed to operating its businesses in an ethical manner. In 2006, we adopted a Code of Business Ethics, which can be viewed on our website.

The Chair of the Human Resources and Compensation Committee is Daryl H. Gilbert, a managing director with JOG Capital Inc. and prior to that an independent consultant in reserves evaluation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (the "Company") and AltaGas Income Trust (the "Trust") (collectively AltaGas Ltd. and the Trust are referred to as "AltaGas") as at and for the year ended December 31, 2010 compared to 2009. This MD&A dated March 2, 2011 should be read in conjunction with the accompanying Consolidated Financial Statements and notes thereto of AltaGas for the year ended December 31, 2010.

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

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other entities.

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

2010 Highlights

The 195 MW Forrest Kerr run-of-river hydroelectric project is tied to a 60-year inflation indexed EPA at $120 to $130 per MWh with BC Hydro. Forrest Kerr has a capacity factor of 55 percent and is expected to commence operations mid-2014.

Our newest project in the Gordondale area of the Montney resource play, will add 120 Mmcf/d of gas processing capacity and deep-cut capability.

Growth and our diversified portfolio of energy assets allowed us to deliver strong operating results in the face of weaker gas and power prices.

Approximately $800 million in available credit facilities, good access to capital markets and debt to total capitalization of 42.8 percent at Dec 2010.

ALTAGAS ORGANIZATION

The material businesses of AltaGas (the Company) are operated by AltaGas Ltd., AltaGas Holding Partnership (formerly Taylor NGL Limited Partnership), AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership, Harmattan Gas Processing Limited Partnership, AltaGas Processing Partnership and AltaGas Utility Group Inc. (Utility Group), collectively the operating subsidiaries.

Prior to July 1, 2010, AltaGas General Partner Inc., through its Board of Directors, the members of which were appointed by the Trustee at the direction of AltaGas Income Trust's (the Trust) unitholders, had been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. As of July 1, 2010, the Board of Directors of AltaGas General Partner Inc. were appointed to the Board of Directors of the Company in accordance with the plan of arrangement approved at the Annual and Special Meeting of Securityholders on June 3, 2010.

The annual MD&A and Consolidated Financial Statements follow the continuity of interest basis of accounting whereby the Company is considered a continuation of AltaGas Income Trust. As a result, this MD&A includes the results of operations for the period up to and including June 30, 2010, when the entity existed as a trust and the Company's results of operations thereafter. At the end of 2010, the Company completed an internal reorganization that formally established three operating divisions – Gas, Power and Utility. The following MD&A is based on these operating divisions.

ALTAGAS' VISION AND OBJECTIVE

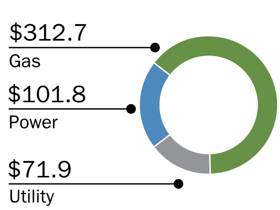
AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. The Company's overall objective is to generate superior economic returns by investing in low-risk, long-life energy assets underpinned by contracts with strong counterparties or regulated returns. Over the past seventeen years AltaGas has built a portfolio of assets that provide the platform to support its future growth. The Company seeks to invest in projects that provide returns that are accretive to cash flow and earnings which in turn provide stable and growing dividends and capital appreciation.

OVERVIEW OF THE BUSINESS

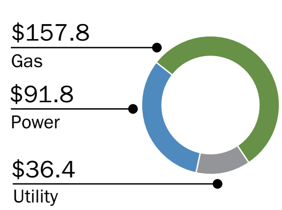
AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. With the physical and economic links along the energy value chain together with its efficient, reliable and profitable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns to its investors. AltaGas focuses on maximizing the profitability of its assets, providing services that are complementary to its existing businesses, and growing through the acquisition and development of energy infrastructure.

AltaGas' Gas business touches more than 2 Bcf/d of gas and includes natural gas gathering and processing transmission and storage. The Power business includes conventional power generation in Alberta and renewable power generation in British Columbia. The Utility business is a rate regulated business earning returns that are driven primarily by regulated rates of return and cost-of-service recovery.

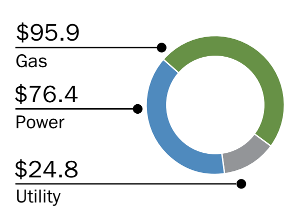
$485.5 million
Net Revenue



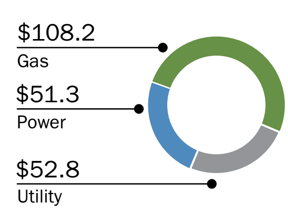
$243.8 million
EBITDA



$151.8 million
Operating Income



$221.9 million
Invested Capital



Excluding Corporate Segment and intersegment eliminations

STRATEGY

In support of its vision and overarching goal of creating long-term shareholder value, AltaGas' strategy has remained focused on four key themes:

- Optimize its existing businesses by focusing on safe and reliable service to its customers and capitalizing on the strategic location of its current assets;
- Grow and diversify its Gas, Power and Utility infrastructure platform;
- Maintain its financial strength and flexibility; and
- Continue to evolve its organizational capability to support the strategy.

AltaGas' Board of Directors reviews the strategy annually, consistent with its mandate of overseeing and directing the Company's strategic direction. The Company continually assesses the macro and micro economic trends impacting its business and seeks opportunities to generate value for shareholders, including acquisitions, dispositions or other strategic transactions. Opportunities must meet strategic, operating and financial criteria.

Optimize, grow and diversify energy infrastructure

The Company has been providing gas processing and marketing services to natural gas producers since 1994. Since that time it has expanded into extraction, transmission, storage and distribution of natural gas as well as natural gas liquids and power generation. The natural gas and power supply and demand fundamentals in North America have consistently underpinned the Company's strategy. In recent years, the supply and demand fundamentals have been changing. AltaGas sees a growing North American gas supply as a result of new technology that has improved the economics of unconventional gas plays, including shale, tight gas and coal bed methane. New technology such as horizontal drilling and multi stage hydraulic fracture drilling allow shale and other low productivity gas resources to be produced more economically. The crude oil, natural gas and natural gas liquids markets are presenting opportunities that the Company is well positioned to capitalize on as a result of its strategically located assets and its capability to add new assets to serve areas which are not yet connected to gas processing, transmission or distribution infrastructure.

Overall, abundant natural gas supply is anticipated to be positive news for North American consumers and is likely to lead to renewed interest in natural gas as an economically priced, clean burning fuel. As a result, the share of natural gas being used for power generation is expected to increase substantially. This is a result of both economic growth and increased demand for clean sources of power to reduce greenhouse gas emissions. AltaGas expects that gas-fired power generation and renewable power generation will be instrumental in the near-term reduction of green house gas emissions. Amid these changing energy supply and demand dynamics, the Company's strategy is to diversify and grow its energy asset portfolio with a focus on gas and power.

Cost efficiency and operating performance is a driver of increasing value as the Company continues to build out its portfolio of assets. Key initiatives that are underway to manage costs include changes to cost tracking systems and implementing best practice procurement strategies. Superior service, safety and reliability are also integral to AltaGas' customer value proposition. Cost management initiatives are balanced with the safe and reliable operation of the Company's assets and the need to ensure ongoing customer satisfaction. With respect to safety, AltaGas strives to employ the best available practices and technologies for integrity management systems and maintenance and operations in order to mitigate risks to the public, employees and the environment.

Maintain financial strength and flexibility

Financial discipline is a fundamental cornerstone of the Company's strategy. As a growth-oriented energy infrastructure company, AltaGas creates value for its investors through minimizing its cost-of-capital and maximizing its return on invested capital which ensures operating cash flows are maintained and growing. AltaGas' financing strategy is built on two key principles: ensure the Company has sufficient liquidity to meet its capital requirements, and do so at the lowest cost possible. The Company develops and executes financing plans and strategies to maintain and improve its credit ratings, diversify its funding sources and maintain ready access to capital markets.

A key element of the Company's low-risk business model is mitigation of exposure to certain market price risks. As a result, the Company has developed robust risk management processes that mitigate earnings volatility from commodity price risk. AltaGas proactively hedges interest rates, foreign exchange and commodity price exposures. As well, the continued management of counterparty credit risk remains an ongoing priority.

Continue to develop organizational capability to support the strategy

AltaGas recognizes that to be successful in operating and constructing energy infrastructure, specific core competencies are required. To that end the Company continues to focus on training and hiring the required competencies for executing the strategy and ensuring that the performance management processes support the long-term objective of creating shareholder value.

EXECUTING ALTAGAS' STRATEGY

In 2010 the expansions of the Pouce Coupe, Acme and Ante Creek facilities and the investment in the Groundbirch facility enabled the Company to increase processing capability to serve producers seeking to capitalize on liquids-rich areas and areas of growing gas supply. The start up of the Peace River pipeline serving the Montney and Doig areas has resulted in higher volumes processed at the Younger Extraction plant. Higher demand for natural gas liquids enabled the Company to renew NGL contracts at its plant gates to reduce the basis differential between plant gate and Mount Belvieu thereby reducing the volatility in earnings and increasing the price received at the plant gate. AltaGas was also able to contract with an end-user to supply gas to its Empress Gas Liquids Joint Venture facility.

Considerable progress was also made in 2010 on optimizing the existing assets by focusing on adding processing capacity at strategic locations to further enhance shareholder value for the long-term. The Company entered into a long-term contract with a major natural gas producer to build and operate a 120 million cubic feet per day (Mmcf/d) natural gas processing facility along with a natural gas gathering system in the Gordondale area to serve the Montney reserve area. The plant will be equipped with liquids extraction facilities to capture the natural gas liquids value for the producer. The plant is expected to be in-service in late 2012. AltaGas anticipates that early processing capabilities will be available by mid-2011 by using existing infrastructure in the area and building a pipeline to its Pouce Coupe facility.

In late 2010, the Company received regulatory approval to build its Co-stream Project at its Harmattan facility. The Co-stream Project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NOVA Gas Transmission Ltd. (NGTL) Western Alberta System to be processed using spare capacity at the Harmattan Complex to recover ethane and NGLs. It will expand the availability of valuable feedstock for Alberta's petrochemical industry and retain extraction revenues and value in Alberta in an economical manner. The project is expected to result in the full utilization of this facility, providing producers with additional capacity to increase their netbacks on the western leg of the NGTL system.

The acquisition of Landis Energy Corporation in early 2010 was another example of the Company's strategy at work as AltaGas seeks to build upon its current asset base and capabilities by geographically diversifying its storage operations. Pursuing natural gas storage in eastern Canada allows the Company to capitalize on the changing North American natural gas demand and supply trends. The most advanced project is the Alton Natural Gas Storage Project located near Truro, Nova Scotia, of which AltaGas has a 50 percent interest. This project complements the Company's growing presence in Nova Scotia as the build out of the Heritage Gas Limited (Heritage Gas) utility continues. AltaGas also continued to develop its Michigan Natural Gas Storage Project, securing land leases and a partner for the project. The Alton and Michigan projects have the potential for 10 Bcf and 50 Bcf of storage capacity, respectively.

The addition of the cogeneration plant at the Harmattan facility is an example of the Company's ability to capitalize on the energy value chain. The new power generation plant further reinforces the success of the AltaGas strategy to optimize and grow both its gas and power infrastructure platform. The 15 MW cogeneration facility provides the steam required for gas processing while providing clean base-load power to the Alberta power market which serves as back stopping for its coal-fired generation capacity resulting from its 50 percent ownership of the Sundance B3 and B4 Power Purchase Arrangements (PPAs). AltaGas plans to add another 15 MW cogeneration plant and distribution system at the Harmattan Complex in conjunction with the Harmattan Co-stream Project. The second cogeneration plant will meet the power demand of the Co-stream Project.

In 2010 AltaGas made significant progress to grow its renewable power platform with the signing of a 60-year Electricity Purchase Agreement (EPA) with BC Hydro and associated long-term arrangements with the First Nations in support of the Forrest Kerr 195 MW run-of-river hydroelectric project. The project is under construction and expected to be in-service in mid-2014. This project adds a significant stream of low-risk, long-life cash flow that supports AltaGas' objective of providing shareholders with stable and predictable cash flows.

The Company has a portfolio of 1,500 MW of wind power projects currently under development. There are approximately 260 MW in the advanced development stages for which AltaGas is seeking contractual arrangements before moving forward. These projects will provide geographic and counterparty diversification thereby reducing overall business risk.

The strategy to grow, optimize and diversify its asset base in a low-risk manner was further enhanced in late 2009 when AltaGas acquired the remaining interests in Utility Group and Heritage Gas that it did not already own. The addition of a regulated asset base to the cash flow profile of the Company has reduced its business risk profile. The build out of a new natural gas distribution utility in Nova Scotia and the rejuvenation of the Alberta utility infrastructure provides an additional platform for AltaGas to meet its objective of providing stable, growing returns to investors. In 2010, the regulated rate base in Alberta and Nova Scotia grew by 10 percent and 20 percent respectively.

In 2010, AltaGas completed several financing transactions that served to support its strategy of maintaining financial strength and flexibility. The Company executed two credit facilities for a total of $800 million with an accordion feature for an additional $200 million. It also issued two senior medium term notes for a total of $375 million, extending its debt maturity profile. The $200 million preferred share issuance in August 2010 was the Company's first such issue and served to strengthen the balance sheet by adding a new form of equity to its balance sheet. At the end of 2010, AltaGas had approximately $775 million of available credit facilities and debt-to-total capitalization of 42.8 percent.

In 2010, the Company further strengthened the organizational capability to deliver its strategy. Due to the significant focus on constructing key projects, the Major Projects group was split into two groups – Gas and Power. Experts were hired in both areas to ensure the organization has the project, engineering and construction management expertise to build these infrastructure projects on time and on budget. Since 2008, AltaGas has invested in its project management training across the Company to further enhance organizational capability in this area. AltaGas also works with world class engineering and equipment manufacturers and undertakes procurement strategies to mitigate project risks.

AltaGas recently completed an internal reorganization that establishes three Divisional Presidents to lead the Gas, Power and Utility businesses with full accountability for the profitability of the assets, working capital management and capital deployment thereby reducing the size of the Corporate segment. The Presidents of the Operating Divisions will ensure that each business is able to customize its operational strategies to meet its unique business needs while aligning with the overall corporate and risk management strategy.

2010 GROWTH HIGHLIGHTS

- Signed a 60-year inflation indexed EPA with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric power generation project. Forrest Kerr is expected to cost approximately $700 million and be in-service by mid-2014;
- Received regulatory approval of the Harmattan Co-stream Project in December 2010. The Co-stream Project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western Alberta System to be processed using spare capacity at the Harmattan Complex to recover ethane and NGLs. The project is expected to commence operations in first quarter 2012. The capital cost estimate is $130 million;
- Announced plans to construct a 120 Mmcf/d gas processing facility and an associated gas gathering system in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The project is subject to regulatory approval. The plant will also be equipped with liquids extraction facilities. The facility and associated gas gathering system is expected to cost approximately $235 million and be in-service in late 2012. By using existing infrastructure in the area and building the Henderson Pipeline to connect to the Pouce Coupe facility, AltaGas anticipates providing processing for early production by mid-2011. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility;
- Entered into an agreement to acquire the 28 Mmcf/d Groundbirch sour gas plant in northeast British Columbia. Under the agreement, AltaGas invested approximately $28 million to construct the gas plant and related infrastructure in return for 100 percent ownership of the gas plant and a dedicated take-or-pay processing obligation;
- Completed a $19 million natural gas distribution pipeline project to Bedford, Nova Scotia. The expansion provides the foundation for further expansion into the growing communities in the Halifax Regional Municipality over the next several years;
- Expansions completed at the Pouce Coupe, Ante Creek and Acme gas processing facilities added a combined 32 Mmcf/d of capacity;
- Completed under budget and on time the construction of a 15 MW gas-fired cogeneration facility at the Harmattan Complex that came into service during fourth quarter 2010. Plans to construct a second 15 MW cogeneration unit are underway;
- Completed year 1 of the system betterment rejuvenation program at the Alberta utility and expansion of the Heritage Gas distribution system. The Utility business increased rate base by 15 percent in 2010; and
- Acquired all of the outstanding common shares of Landis Energy Corporation. Landis is a developer of underground natural gas storage facilities, focused on opportunities in Atlantic Canada. The acquisition was valued at an estimated $25.6 million.

2010 FINANCIAL HIGHLIGHTS

- Completed a $200 million issue of senior unsecured medium term notes. The notes carry a coupon rate of 5.49 percent and mature on March 27, 2017;
- Entered into a series of agreements on June 30, 2010 for a new three-year $600 million extendible unsecured revolving term credit facility with a syndicate of nine banks. The new syndicated credit facility has a $200 million accordion feature that allows AltaGas to increase the credit facility to an aggregate amount of $800 million;
- Reorganized into a dividend paying corporation on July 1, 2010;
- Completed a public offering of 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 (the “Offering”) on August 19, 2010. The Offering resulted in gross proceeds of $200 million;
- Completed its $175 million issue of senior unsecured medium term notes on November 26, 2010. The notes carry a coupon rate of 4.6 percent and mature on January 15, 2018;
- Generated net income applicable to common shares of $97.2 million ($1.19 per share) compared to $141.3 million ($1.80 per share) in 2009;
- Reported earnings before interest, taxes, depreciation and amortization (EBITDA)[1] of $243.8 million ($2.99 per share) compared to $251.5 million ($3.20 per share) in 2009;
- Generated Funds from Operations[1] of $195.0 million ($2.39 per share) compared to $202.3 million ($2.58 per share) in 2009; and
- AltaGas’ debt-to-total capitalization ratio as at December 31, 2010 was 42.8 percent compared to 49.2 percent at December 31, 2009.

1 Includes financial measures not included under Canadian GAAP. Please see discussion in “Non-GAAP Financial Measures” of this MD&A.

Gas Business

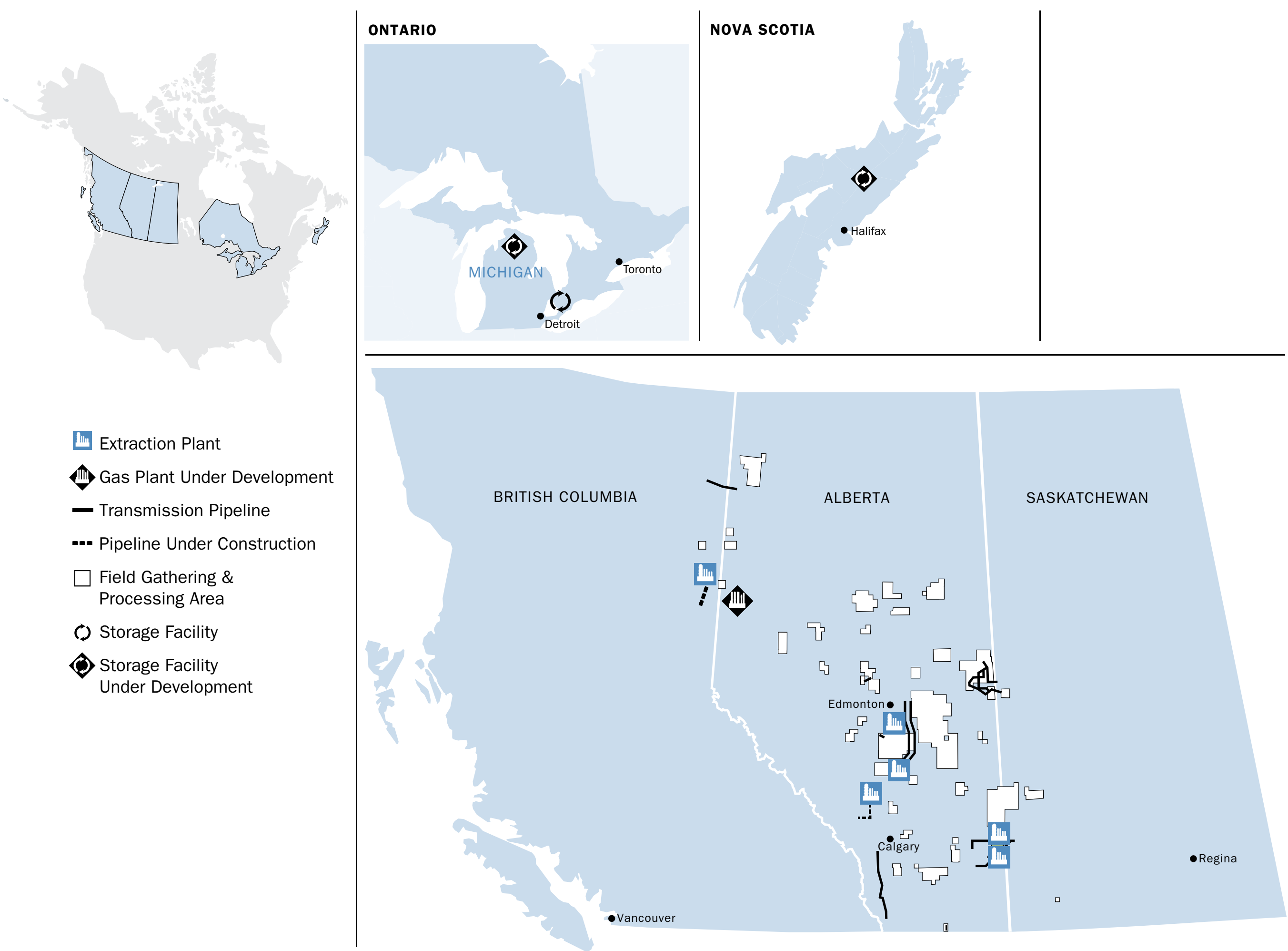
DESCRIPTION OF ASSETS

AltaGas' Gas business touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids (NGLs) extraction and fractionation, transmission and storage. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGLs. AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.2 Bcf/d of raw gas processing capacity.

Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by providing energy consulting and supply management services to non residential end-users, buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of the processing assets. The Gas business also includes several expansion and greenfield projects under development and construction.

The Gas business includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1,594 Mmcf/d. The extraction assets provide stable fixed fee or cost-of-service type revenues and margin based revenues;
- Five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d;
- More than 70 gathering and processing facilities in 31 operating areas in western Canada and a network of 6,500 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets;



- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn hub in Eastern Canada;
- Harmattan Co-stream Project under construction with expected in-service date of first quarter 2012;
- Gordondale gas processing plant with deep cut extraction capability in regulatory process with planned in-service date of late 2012;
- Several expansion projects to meet producer needs in the liquids-rich and solution gas formations;
- 50 percent interest in a natural gas storage project under development in Nova Scotia with potential gross storage capacity of 10 Bcf and in Michigan with potential storage capacity of approximately 50 Bcf; and
- Energy consulting, natural gas buys and sells and gas transportation services to optimize the value of the infrastructure assets and meet customer needs.

Capitalize on Opportunities

AltaGas pursues opportunities to deliver value to its customers and enhance long-term shareholder value. The Company's objectives are to:
- Increase throughput and utilization of existing facilities;
- Be the most cost-effective provider of midstream services while delivering reliability and operating in a safe manner;
- Mitigate volume risk by directly recovering operating costs from customers;
- Acquire and develop new gas infrastructure assets to meet customers' needs; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration of business lines across the energy value chain.

AltaGas' Gas business provides safe and reliable natural gas and liquids gathering, processing, extraction, transportation and storage services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, expanding and adding new infrastructure and redeploying assets to capitalize on increased exploration and drilling activities in the Western Canada Sedimentary Basin (WCSB or Basin). AltaGas also focuses on increasing long-term, fixed fee and cost-of-service contracts with strong counterparties to mitigate the impact of volume risk and increase stability of earnings.

Until recently, the WCSB was considered to be a maturing basin. Recent technological advancements have resulted in a significant change in the cost of production of natural gas in the Basin. As a result, AltaGas remains confident that the long-term demand for natural gas, combined with improvements in exploration, drilling and completion technology, will support the long-term viability of the Basin. The emergence of unconventional gas plays in the WCSB such as Montney and Horn River, as well as increased focus on horizontal multi-fracturing technology have provided renewed life to the Basin. As natural gas supply increases AltaGas expects growing demand for processing infrastructure in the WCSB. Strong NGL prices have resulted in increased producer focus on liquids-rich and solution gas thereby increasing the demand for processing capacity that allows producers to earn higher netbacks on liquids-rich gas.

The supply and demand fundamentals for natural gas and natural gas liquids provide significant growth opportunities in the Company's Gas business as plant modifications and additions are required to increase product recoveries. AltaGas expects to capitalize on these opportunities by increasing throughput at facilities, by increasing interests in existing plants, and acquiring and constructing new facilities in areas with growing demand for natural gas processing, extraction, storage and transmission capacity.

The natural gas supply to all extraction plants depends on natural gas demand pull from residential, commercial and industrial usages inside and outside of Western Canada, and gas liquids demand pull from the Alberta petrochemical, propane heating and Canadian oil and gas industries. AltaGas' Empress extraction plants rely on natural gas exports via the NGTL eastern gate, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and increase asset utilization and profitability. The Harmattan Co-stream Project will also increase utilization at the plant. The cost-of-service arrangement for the Co-stream project adds long-life, low-risk stable cash flow that further strengthens AltaGas' business risk profile and creates significant shareholder value.

AltaGas also expects to see increased opportunities to acquire or build gathering and processing infrastructure from or on behalf of producers wishing to redeploy capital to exploration and production activities rather than dedicating to non-core activities such as processing. The Company also expects there to be opportunities to increase volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance competitive advantages. The strategic location of some of its existing infrastructure will allow the Company to capitalize on growing natural gas production in northeast B.C. and northwest Alberta, as well as unconventional sources of gas, such as shale and coal bed methane. In addition, AltaGas is able to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers since most of the field gas compression and processing units are skid mounted.

The proposed Gordondale plant will meet liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. Overall, the diverse nature of its field processing and extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability. The contractual underpinning of the Gordondale plant provides investors with stable cash flows and the opportunity to further enhance returns due to the strategic location of the facility.

Due to the integrated nature of AltaGas' gas assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is required to meet producer and market demands. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure-based businesses. These include increasing margins earned in transmission, maintaining the cost-effective flow of gas through extraction plants and increasing services provided to producers. AltaGas has significant gas and electricity market knowledge which it employs across all its assets to enhance value along the energy value chain and more effectively serve customers' needs across Canada.

Gas Outlook

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

AltaGas expects higher volumes within the field processing business as a result of 2010 expansion projects at the existing Pouce Coupe, Ante Creek and Acme gas processing plants and the expected acquisition of Groundbirch. Expansions and plant modifications at Alder Flats and Blair Creek, connection of the new Henderson pipeline to the Pouce Coupe plant and higher producer activity in the Bantry and Princess areas are expected to more than offset the volume declines at some of the 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.

Throughput at the extraction assets is expected to increase in 2011 over 2010 despite the scheduled turnarounds at the Harmattan and Younger facilities. Drilling activity in northeast B.C. has increased as producers continue the development of tight and shale gas plays within the area. Development in this area is expected to result in higher volumes being processed at the Younger Extraction Plant. Higher extraction volumes through our Empress facilities are expected due to successful contracting of gas supply to increase utilization at these facilities. In addition, operating income within the Gas business during 2011 is expected to be greater than 2010 due to lower amortization, which has been estimated to be $7 million, as a result of changes in expected lives at certain facilities. Offsetting these gains will be the 2011 turnarounds that are expected to result in an operating income impact of $8.5 million. The turnarounds at the Younger and Harmattan facilities are expected to occur in second and third quarter, respectively. In addition, the lower daily contract quantity on the Suffield system is expected to result in lower operating income of approximately $6 million in 2011 compared to 2010.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve for 2011, management expects NGL frac spread prices to average approximately $35/Bbl. In 2011, the Company estimates that 13 percent of total extraction volumes will be exposed to frac spread. In 2011, approximately 70 percent of the exposure has been hedged at an average price of $26.85/Bbl.

Gas Risk Management

AltaGas' Gas assets process and transport natural gas and NGLs produced in the WCSB. Utilization of the assets is dependent on a number of factors including natural gas supply and demand, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the long-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for market participants. The utilization of extraction plants is influenced by natural gas composition and the difference between the value of the ethane, propane, butane and condensate as separate marketable commodities versus their value in a heat content basis within the natural gas stream.

In the energy services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies as well as other energy consulting firms. The most significant risk in this aspect of the Gas business is counterparty credit risk. The credit intensive nature of this business requires balance sheet support to enable the execution of fixed price natural gas purchase and sale agreements. Storage spreads that support the economic fundamentals of the Company's storage business is also a risk.

AltaGas manages its exposure to risk in the Gas business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
LONG-TERM VOLUME DECLINES	• Contract provisions underpin capital commitments • Long-term contracts independent of throughput, such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities • Increase geographical and customer diversity to reduce exposure to individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas businesses to increase volumes through its processing facilities	• In 2010, a majority of extraction ethane production was sold under long-term cost-of-service or fee for service contracts • 98 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed-fee • New Field Gathering and Processing (FG&P) facilities and expansions underpinned by take-or-pay contracts • Completed expansions at Pouce Coupe and Ante Creek facilities to serve growing production in northeast B.C. and northwest Alberta • Entered long-term contract with Encana Corporation to build Gordondale plant to serve the liquids-rich Montney area • Completed the acquisition of Landis Energy Corporation to grow and diversify the natural gas storage business over time with potential for 10 Bcf of storage capacity in Nova Scotia • Progressed discussions with partners and landowners to move Michigan storage forward • Over 260 customers with no customer representing more than 7 percent of FG&P net revenue during 2010 • Top 10 FG&P customers represented 9 percent of consolidated net revenues in 2010 • 77 FG&P facilities in 31 operating areas in three provinces within the WCSB • Interest in six of Canada's 10 NGL extraction facilities • First full year of operations of Sarnia Storage • Empress extraction facilities maintained high capacity utilization • Harmattan Co-stream Project to increase utilization and extract liquids-rich gas from the western leg of the NGTL system
INCREASING OPERATING COSTS	• Acquire large working interests to control and optimize operations and maximize efficiencies • Contractual provisions provide for recovery of operating costs • Centralized procurement strategy to reduce costs	• Approximately 40 percent of FG&P's and Extraction and Transmission's (E&T) operating costs were recovered through contract provisions in 2010 • Operate and control 74 of 77 FG&P facilities • Operate and control all transmission assets • Operate and control four of six extraction facilities • Average FG&P working interest of 93 percent and average E&T working interest of 82 percent • Maintenance management and centralized purchasing programs ensure tight cost controls and equipment reliability
OPERATIONAL	• Maintain control over operational decisions, operating cost and capital expenditures by operating our facilities • Maintain written standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs	• Operated and controlled 74 of 77 FG&P facilities at 98 percent reliability • Operate and control all transmission assets • Operate and control four of six extraction facilities • Successful operator competency program closely monitored and improved • Successful maintenance management program to ensure facility integrity
COMMODITY PRICE AND STORAGE SPREAD FLUCTUATION	• Contracting terms, processing, storage and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions • Employ hedging practices to reduce exposure to frac and storage spread volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility	• Less than 13 percent of total extraction production was exposed to frac spreads in 2010 • Most ethane production sold under long-term, cost-of-service or fee-for-service • 62 percent of NGL production under long-term, fixed-fee arrangements • 98 percent of revenue in transmission business is underpinned by take-or-pay contracts

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
COMMODITY PRICE AND STORAGE SPREAD FLUCTUATION (Continued)	• Commodity Risk Policy prohibits transactions for speculative purposes • Have strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy • In depth knowledge of transportation systems, natural gas and NGL markets	• Approximately 70 percent of volumes exposed to frac spread for 2011 and 16 percent for 2012 have been hedged • NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce • Majority of FG&P contracts are volumetric service fee structures, based on a rate per Mcf of throughput reducing direct commodity price risk compared to a percentage of price arrangement • All gas marketing transactions are back to back with locked in margins • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk • Storage fees based on fixed price contracts in 2010
COUNTERPARTY	• Strong credit policies and procedures • Continuous review of counterparty credit • Establish credit thresholds using conservative credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • Agency arrangements in energy management whereby counterparty credit risk for commodity is between the supplier and end-user • Active accounts receivable monitoring and collections processes in place • Credit mitigants included in gas processing contracts	• Over 260 FG&P customers with no customer representing more than 7 percent of FG&P net revenue during 2010 • Majority of the exposures are to investment grade counterparties • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees • No energy services customer represented more than 10 percent of consolidated revenues during 2010 • AltaGas purchases natural gas from a wide array of investment grade suppliers • Liens placed on natural gas volumes owned by customers, but processed by AltaGas to collect accounts receivable in accordance with contractual terms
CONSTRUCTION	• Major Projects Group manages and monitors significant construction projects • Strong project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks	• Practiced effective procurement policies and procedures and vendor selection • Fixed price quotes for most major equipment components • Redeploying equipment from underutilized plants • Established Major Project – Gas group, hired senior executive and project team members • Steering committees provide strong project governance • Expect to contractually fix approximately 60 percent and two-thirds of capital costs for Harmattan Co-stream Project and Gordondale Gas Plant Project, respectively
REPUTATION	• Maintain active corporate and regulatory affairs department	• Held several events to inform and educate the communities in which AltaGas is operating, constructing and developing projects
REGULATORY	• Regulatory and commercial personnel monitor and react to regulatory issues • Proactive government relations group • Build risk-mitigation into contracts where possible	• AltaGas continued active participation in industry committees and regulatory forums in 2010 • Improved communication in communities in which we operate • Received regulatory approval of the Harmattan Co-stream Project in December 2010
ENVIRONMENT AND SAFETY	• Strong safety and environmental management systems, which AltaGas continually strives to improve	• Audits resulted in AltaGas maintaining its Certification of Recognition from Alberta Human Resources and Employment • In 2010, AltaGas received its highest scores since inception for safety and environment audits • There were no lost-time accidents in 2010 • Participated in industry programs, including the annual Safety Stand Down

Power Business

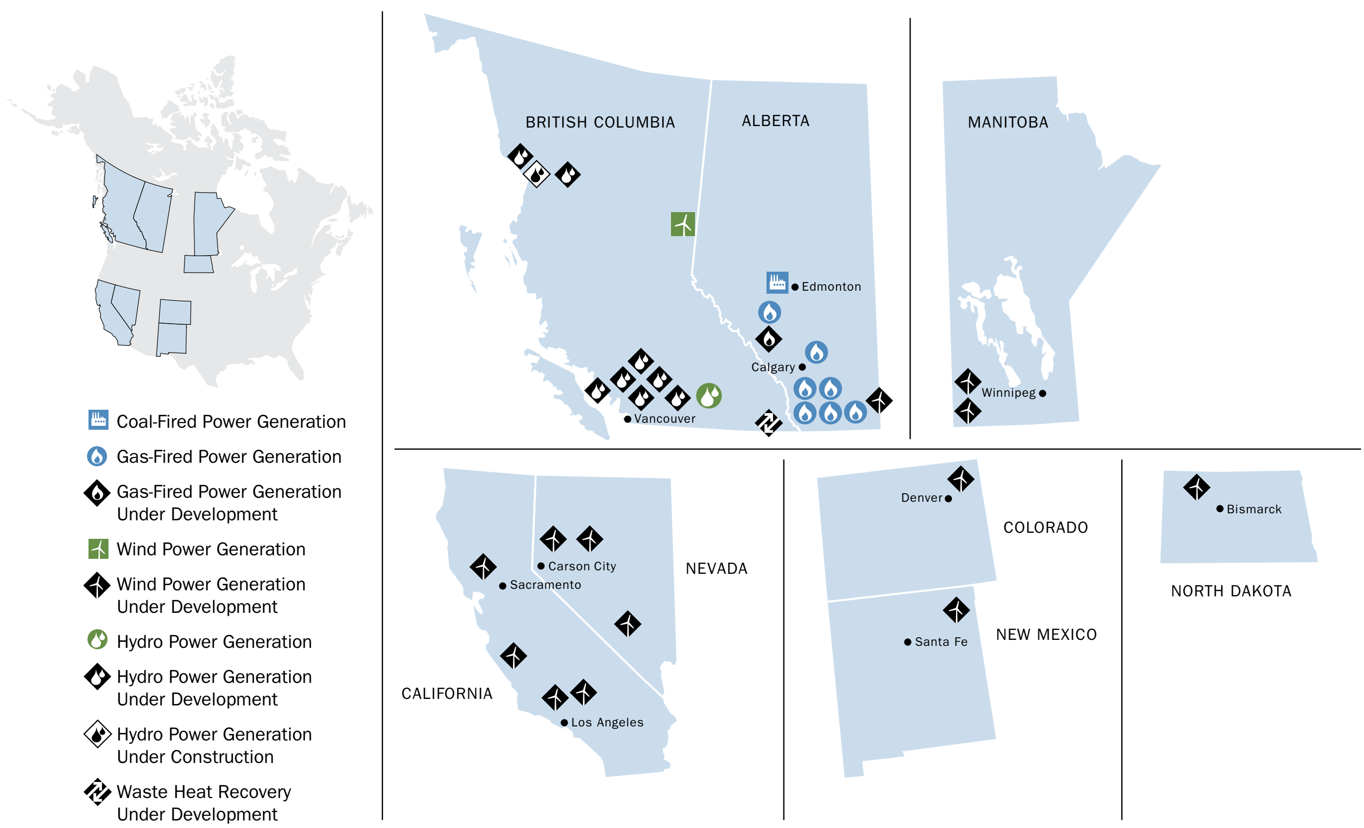
DESCRIPTION OF ASSETS

The Power business includes operating assets in conventional power generation in Alberta and wind power generation in British Columbia. In addition, there is a 195 MW Forrest Kerr run-of-river project under construction in northwest British Columbia and more wind and run-of-river projects under development in Canada and the United States. We have also recently announced plans to pursue another 15 MW cogeneration project at the Harmattan complex and a 6 MW of waste heat recovery project in Sparwood, British Columbia.

The power business comprises 407 MW of total power generation capacity in Alberta and 102 MW from the Bear Mountain Wind Park. AltaGas owns 50 percent of the Sundance B PPAs, giving it the rights to power output and ancillary services from 353 MW of coal-fired base-load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 39 MW of gas-fired power peaking capacity in southern Alberta. In late 2010 the Company commissioned 15 MW gas-fired cogeneration facility at the Harmattan Complex. This 54 MW of gas-fired capacity provides fuel diversity to AltaGas' Power business and partially backstops outages at Sundance. The cogeneration facility provides steam to the gas processing facility as well as base-load power to the Alberta electric grid. The peaking plants also provide revenue from the sale of energy and ancillary services due to their quick ramp-up capability.

The Company employs a power hedging strategy which is designed to balance market and operational risk related to the Sundance PPAs, thereby reducing the exposure to power prices and providing earnings stability in the power business in Alberta. Hedges are executed with industry participants and are subject to credit reviews and credit thresholds in the normal course of business. AltaGas also sells power to commercial and industrial end-users in Alberta, providing further earnings stability.



AltaGas recognizes that climate change concerns give rise to opportunities to create value. The Company is committed to capturing and retaining that value for its shareholders. AltaGas tracks and maintains its inventory of credits and offsets and pursues opportunities to generate emissions credits or offsets through efficient and environmentally responsible operations of existing or new assets. Lower emissions costs are also achieved by sourcing third-party emissions credits at costs that are lower than paying into the fund established by the Specified Gas Emitters Regulations (SGER) in Alberta.

In addition to the 102 MW Bear Mountain Wind Park near Dawson Creek, British Columbia, AltaGas also owns a 15 percent effective interest in a 7 MW run-of-river hydroelectric power generation facility in near Boston Bar, British Columbia. The Bear Mountain Wind Park is backstopped by a 25-year EPA with BC Hydro. AltaGas retained the green attributes and Renewable Energy Credits (RECs) related to the project. These credits have recently been certified by the California Energy Commission, enabling AltaGas to sell them in the California market. In addition, Bear Mountain has qualified for the Federal Government of Canada's ecoEnergy renewable initiative (eRPI), which grants $10/MWh generated by the Bear Mountain Wind Park for 10-years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with the manufacturer of the wind turbines to operate and maintain the turbines.

Capitalize on Opportunities

AltaGas pursues opportunities in this segment to enhance long-term shareholder value. Its objectives are to:

- Execute power hedges to balance operational and market risk and to increase earnings stability from its Alberta power assets;
- Operate and dispatch the gas-fired peaking capacity to maximize revenue from both energy sales and ancillary services and minimize operating costs;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements or supported by strong power supply and demand fundamentals; and
- Grow and diversify the power generation portfolio by geography and fuel source.

AltaGas' strategy is to build, own and operate long-life, low-risk power infrastructure assets to deliver strong, stable returns for investors. Growth is focused on clean and renewable sources of energy as the Company seeks to capitalize on increasing demand for clean power while reducing its carbon footprint.

The demand for renewable and clean generating capacity continues to be strong across North America, as industry prepares to address climate change legislation and utilities are faced with renewable portfolio standards. However, the poor economic environment in 2008 and 2009 resulted in slowed demand growth for power. In Alberta specifically, average power demand had remained essentially unchanged since 2008, but showed renewed growth in 2010 at a rate of approximately 2.5 percent. AltaGas expects power demand growth to follow suit with a broader economic recovery, which is expected to lead to a recovery in power prices. The potential retirement of a 560 MW coal-fired generator announced in early February 2011 has resulted in stronger and more volatile power prices since the announcement.

The Sundance B facility is among the lowest cost producers of power in the province, uniquely positioning AltaGas to maintain profitable operations during difficult economic conditions. The evolution of the Rate Regulated Option (RRO) has changed the wholesale power market dynamics in Alberta. As of July 1, 2010 the RRO is based entirely on the month ahead market price of electricity. RRO providers submit their regulated rate proposals to the appropriate regulatory body for approval. The Alberta Utilities Commission (AUC) regulates investor owned utilities and approves RRO rates for the cities of Calgary and Edmonton and rural Alberta. Before July 1, 2010 the RRO was calculated using a combination of both short and long-term market prices for electricity. The new RRO pricing mechanism has resulted in lower liquidity in the long-term market. While the changing market dynamics have presented opportunities for AltaGas to capitalize on the short-term price volatility this results in less opportunities to enter into long-term hedges.

AltaGas' primary means of securing long-term power sales is through its Commercial and Industrial (C&I) power retail business. AltaGas actively markets electricity directly to end-users, enabling the Company to secure fixed price sales at competitive market prices while earning fees associated with the administration of the metered data and billing. These C&I sales are typically for 3 to 5 year terms, offering AltaGas price certainty and a source of liquidity that has decreased in the wholesale market. Currently, AltaGas has approximately 60 MW of fixed price sales to C&I customers for 2011 and 2012, 50 MW for 2013 and 45 MW for 2014, all with average prices in the low $60's per MWh, excluding retail fees.

Power generated from the Bear Mountain Wind Park is not currently exposed to power price volatility as the power generated is sold to BC Hydro at a fixed price with 50 percent escalated by the Canadian Consumer Price Index (CPI) for 25-years. The British Columbia power market is established by the government's strategy to increase its green footprint and enter into electricity purchase arrangements with independent power producers. While the BC power market is linked to some of the northwest Electric Regions, namely Mid-Columbia (Mid-C) and the California Oregon Border (COB) the price received by AltaGas for power generated by Bear Mountain is driven by the contractual arrangement with BC Hydro. AltaGas also receives eRPI funding of $10 per MWh from the Federal government of Canada. In addition to the price received for power generated, AltaGas receives the economic benefit of any RECs produced as a result of power generated from Bear Mountain. There is significant opportunity to capitalize on the demand for RECs as North America moves forward on its climate change policies and establishes renewable portfolio standards for utilities.

Opportunities to develop and own additional power generation are also likely to arise due to the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. The federal government's stated policy to have coal-fired generators retire at the end of their useful economic lives may prompt additional opportunities to develop new clean power generation capacity. The 102 MW Bear Mountain Wind Park in addition to the Forrest Kerr run-of-river project under construction and the McLymont and Volcano run-of-river projects under development are all examples of AltaGas' strategy in action.

AltaGas has approximately 1,900 MW of renewable power under development, including 1,500 MW of wind power developments, 205 MW of run-of-river hydroelectric developments and 195 MW run-of-river hydroelectric under construction. The wind projects are geographically dispersed in western North America, with 500 MW in Canada and 1,000 MW in the northern and western United States, while the run-of-river projects are located in British Columbia.

Power Outlook

AltaGas has altered its approach to hedging its Alberta power generation. Changes in the Alberta power market, particularly the changes to the RRO have focused liquidity into the prompt month while decreasing liquidity for longer term products. For first quarter 2011, AltaGas has hedged approximately two-thirds of the expected Alberta-based power generation at an average price of $63.50 per MWh. For the second through fourth quarters of 2011, AltaGas has hedged approximately one-third at an average price of $65 per MWh. On a full year basis, AltaGas is approximately 40 percent hedged at an average price of $64.50 per MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages, as it has successfully done to date in 2011.

On February 8, TransAlta announced its intentions to terminate the Sundance A PPA, which will have the effect of permanently removing approximately 560 MW, or 4 percent of the generation supply in Alberta. The Sundance B PPA generating units, which support AltaGas' PPA generation, are approximately five years newer than the Sundance A generating units, the term of the Sundance B PPAs is three years longer, and unit 4 of Sundance B saw a significant capital investment by its owner in 2007 when its capacity was increased by approximately 53 MW. Therefore, management does not believe the risk of a similar event happening with Sundance B is significant. Upon announcement of the potential termination of the Sundance A PPA, forward prices immediately increased, marking a fundamental shift in the market that results in a more sustainable supply/demand/ price balance in the province. Current forward prices, as published in daily broker reports, are in the low $60's per MWh for the balance of 2011 as well as 2012 and 2013.

The impact of the addition of the Harmattan cogeneration facility in late 2010 will also help strengthen results from the power business in 2011. According to AESO, if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 3,800 MW of new generation may be required by 2016. Improved economic conditions in Alberta are expected to bring increased power demand to the province and provide further support to prices over the long term.

Risk Management

In Alberta, the main risks faced in the Power business are power prices, the cost of power, volume of power generated, counterparty risk and regulatory risks related to the deregulation of power, market regulation and environmental legislation. Power results are generally driven by volumes of power generated, hedge prices, spot power prices, the cost of power and transmission. Power prices in Alberta are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, and economic activity. The cost of power is driven by operating costs, changes in transmission rates and power available for sale, mainly due to outage and force majeure events. In British Columbia, the risks impacting financial performance are weather and operational performance of the turbines. AltaGas mitigates these risks through the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
POWER PRICE VOLATILITY	• Disciplined hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • In depth Alberta power market knowledge and experience • Hedge own electrical demand requirements • Direct marketing to end-use customers • Own and operate gas-fired peaking capacity to backstop PPAs and sell energy and ancillary services • Increase base-load generating capacity • Execute long-term inflation adjusted electricity purchase arrangements with power buyers	• Average sales price received in 2010 was $66.79 per MWh, compared to average monthly Alberta Power Pool spot price of $50.76 per MWh • Hedged 63 percent of generation in 2010 • Supplied approximately 9 MW for own use in 2010 • Supplied approximately 60 MW to Alberta commercial and industrial customers under one to five year contracts • Peaking plants contributed $5.2 million to net revenue in 2010 through sales of ancillary services and energy • Commissioned the Harmattan cogeneration facility that increased the volume of low-cost efficient base-load power generated • Power generated from Bear Mountain Wind Park covered under 25-year EPA with BC Hydro; power price is inflation adjusted for 50 percent of CPI • Entered 60-year EPA fully indexed to CPI with BC Hydro for power generated from Forrest Kerr
VOLUME OF POWER GENERATED	• PPAs include specified target availability levels • Diversification of fuel sources and geography • Hedging strategy to balance price and operating risk • Undertake extensive wind and hydrological studies to support investment decisions	• The operator of the Sundance B plant is obligated to provide AltaGas financial compensation for shortfalls below the specified target availability level, which was 86 percent of rated capacity in 2010. Payment is based on the difference between actual and target availability multiplied by the 30 day rolling average power price (RAPP) • 39 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs • 15 MW of base-load cogeneration completed in late 2010 to provide further backstopping to the Sundance PPAs • Full year power generated in 2010 from the Bear Mountain Wind Park • Installed 5 met towers during 2010 to monitor and study wind power development projects; exit 2010 had 31 met towers installed • Forrest Kerr project is supported by 40 years of hydrologic data and analysis
COST OF POWER	• Hedge power costs • Avoid commodity price exposure on electricity energy sources	• Cost of power from the coal-fired generation based on PPA indices not market price of coal

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
OPERATIONAL	• Long-term maintenance contract with wind turbine manufacturer (Enercon) • Fixed price O&M contracts with equipment manufacturers • PPAs include specified target availability levels • Hedging strategy used to balance price and operating risk; deliveries of certain hedge contracts are suspended if there is an outage at Sundance B • Backstop Sundance B PPA operations by adding new power generation capacity • Develop standard operating procedures to maximize reliability, safety and output	• Bear Mountain Wind Park turbines under warranty • Power curve and reliability guarantees provided by turbine manufacturer • Revenue from Sundance B PPA based on target availability • Active hedging program during 2010 for Sundance B PPA power generation volumes balancing operational risk with market risk • Balance availability and production from gas-fired peakers to maximize revenue and minimize operating costs • Gas-fired peakers dispatched from central location
COUNTERPARTY	• Strong credit policies • Continuous review of counterparty credit worthiness • Establish credit thresholds using conservative credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Contracts with strong counterparties	• All relevant policies and processes were enforced in 2010 • All wholesale financial hedge counterparties are investment grade • No wholesale counterparty defaults in 2010 • Alberta retail credit risk has little impact on hedge portfolio on an individual basis. In the event of a default, AltaGas can sell the power on the spot market • Bear Mountain contracted with BC Hydro • Entered 60-year contract with BC Hydro for Forrest Kerr
CONSTRUCTION	• Major Projects Group manages and monitors significant construction projects • Strong project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks	• Qualified and experienced team engaged to construct Forrest Kerr • Significant internal project and construction management expertise • Procurement strategy balances cost certainty with project risks • Completed construction of the 15 MW Harmattan cogeneration facility in 2010 on time and under budget • Built a 40:1 scale model of the intake structure for Forrest Kerr to mitigate engineering risk • Strong engineering expertise provided by key service provider • Strong working relationship with BC Hydro • At the end of 2010, approximately 20 percent of the cost for the Forrest Kerr project had been fixed; expect to have 75 percent of the project cost contractually committed to fixed price contracts by December 31, 2011 and 90 percent contractually fixed by the end of 2012
REPUTATION	• Active corporate and regulatory affairs departments	• Completed an Impact Benefit Agreement with the Tahltan in support of the Forrest Kerr project • Held several events to inform and educate the communities in which AltaGas is operating, constructing and developing projects
REGULATORY	• Regulatory and commercial personnel monitor and react to regulatory issues • Build risk-mitigation into contracts where possible	• AltaGas' Sundance B PPAs have provisions for financial relief in the event that policies and regulations render PPAs uneconomic • AltaGas personnel participate in industry policy and oversight committees
ENVIRONMENT AND SAFETY	• Strong safety and environmental management systems, which AltaGas continually strives to improve • Focus on mitigating the impact of the SGER	• Bear Mountain Wind Park generates renewable energy certificates • Bantry and Parkland gas-fired peaking plants use compressed natural gas to drive the peaking plant starter motors; compressed gas is then captured and cycled through the peaking plants rather than vented into the environment • Generate offsets and emissions performance credits from existing AltaGas operating facilities

Utility

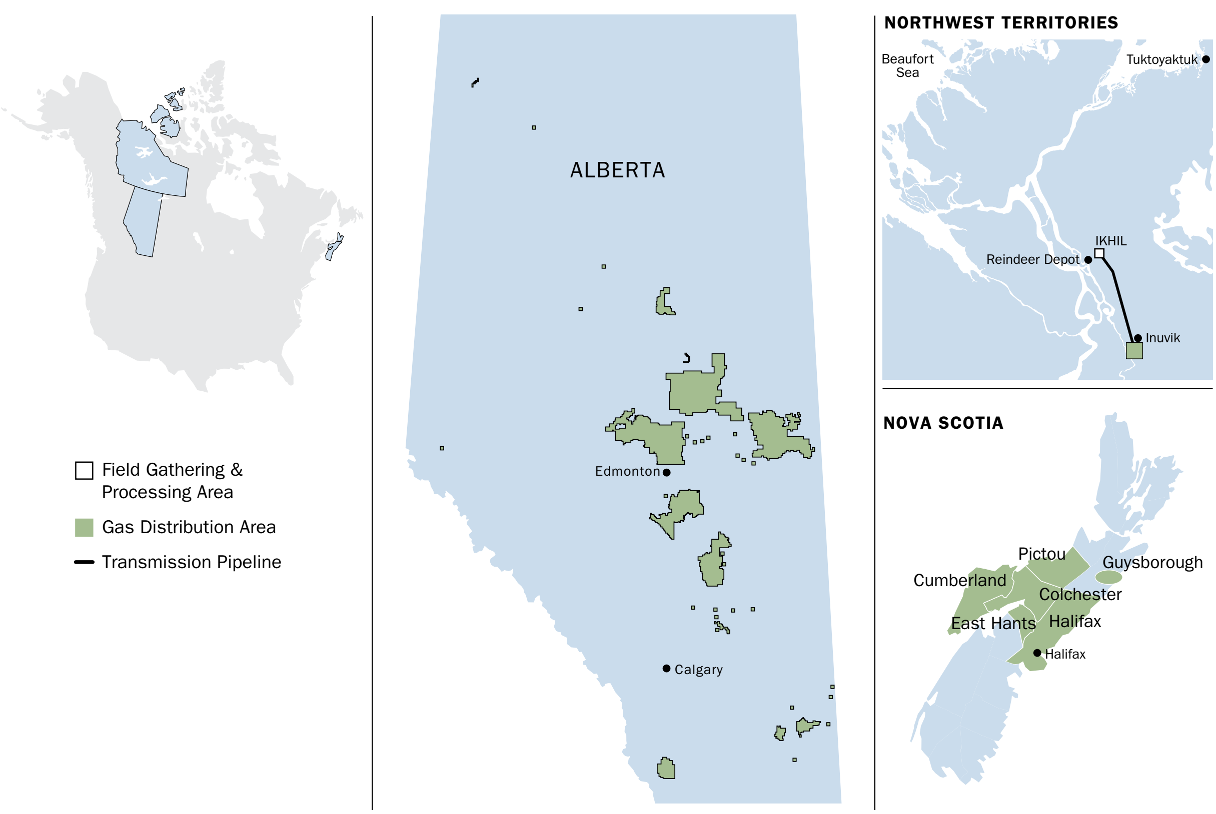
DESCRIPTION OF ASSETS

The acquisition of rate regulated assets in 2009 is another example of AltaGas' strategy at work. The low-risk, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable earnings and cash flows. The Utility business enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Company's business risk profile, thus allowing the Company to meet its objective of generating superior economic returns by investing in low-risk, long-life assets with stable earnings.

AltaGas owns and operates utility assets that deliver natural gas to end-users in Alberta, Nova Scotia and Inuvik, Northwest Territories. The Utility business is comprised of 100 percent interests in AltaGas Utilities Inc. (AUI), the Alberta utility business and Heritage Gas, the Nova Scotia utility business, a one-third interest in Inuvik Gas Ltd. (Inuvik Gas) and a 33.3335 percent interest in the Ikhil Joint Venture (Ikhil).

AUI and Heritage Gas operate in regulated marketplaces where they are allowed to earn regulated returns that provide for recovery of costs and a return on capital from the capital investment base. Return on rate base comprises regulator allowed financing costs and return on equity. Inuvik Gas operates a natural gas distribution franchise in a "light-handed" regulatory environment where delivery service and natural gas pricing are market based.

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



Regulatory Process – Delivery Tariffs

AUI's and Heritage Gas' delivery tariffs are designed to recover their approved cost-of-service and their approved return on equity. Tariffs are determined through a two phase General Rate Application (GRA) or Tariff Application (GTA). Phase 1 establishes the revenue requirement and Phase 2 sets the rates to be charged to various customer classes.

AUI seeks approval of its revenue requirement through a negotiated settlement process with interested parties or through an administrative hearing before the AUC. The AUC monitors the negotiated settlement process and AUC approval is required for any settlement AUI reaches with interested parties. Factors affecting AUI's revenue requirement include forecasts for rate base, distribution and other revenue, operating costs, depreciation, financing costs, income taxes and return on rate base. Heritage Gas uses an administrative hearing for the two phases of the regulatory process.

Although the approved revenue requirement and subsequent approved rates are based on forecasts, and actual results can differ from these forecasts, no adjustment is made to either the revenue requirement or rates for actual results varying from forecast. Once the rates are approved for a period, all risks and benefits from differences in actual versus forecast energy units delivered, capital expenditures, numbers of service sites billed, operating costs, debt servicing costs and taxes are borne by AltaGas' shareholders. Actual returns achieved can therefore differ from allowed returns.

AltaGas Utilities Inc.

AUI serves 70,788 customers (2009 – 69,370), primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. The growth of AUI's service sites and business generally occurs through infill growth in established franchises. Growth for space and water heating in AUI's service areas continues to be concentrated in town distribution systems and relates to servicing new homes and commercial developments with natural gas. AUI serves almost all of the potential market in its existing service areas. New service site installations during 2010 were 1,592 compared to 1,241 in 2009. AUI's rate base growth during 2010 was $12.4 million, or 10 percent, which is the highest in AUI's recent history.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality (HRM). Heritage Gas is a relatively new energy alternative in the province and will continue to require significant capital investment as the natural gas distribution infrastructure is constructed to provide new services to consumers in its franchise areas. Heritage Gas provides Nova Scotia consumers with the opportunity to switch heating fuel sources, mainly from oil or electricity to natural gas. In Heritage Gas' current development stage, the actual revenues billed to customers are less than the revenue required to earn the regulated rates of return. Heritage Gas is allowed to accumulate, up to a maximum of $50 million, a revenue deficiency account (RDA) for this shortfall. The RDA is a component of Heritage Gas' rate base upon which it earns a return.

Potential customers are those with direct access to natural gas service and the opportunity to switch heating fuel sources, mainly from oil or electricity, to natural gas. At the end of 2010, Heritage Gas had 9,435 potential customers that had access to its distribution system. Of these potential customers, Heritage Gas has installed service lines to 3,247 potential customers of which 2,937 were activated before the end of 2010. Heritage Gas' rate base growth during 2010 was $23.8 million, or 20 percent.

Heritage Gas has approval from the Nova Scotia Utility and Review Board (NSUARB) to use the RDA. The RDA changes based on the difference between the actual revenue billed and the revenue required to earn the rates of return approved by the NSUARB. In Heritage Gas' early development stage, it is expected that the actual revenue billed will be less than the revenue required to earn the approved rates of return and therefore an RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rates of return, and the RDA will be drawn down. In September 2010, AltaGas completed the RDA consultation process with NSUARB with a successful negotiation that the Heritage Gas RDA will not exceed $50 million. Heritage Gas may, if necessary, apply to the NSUARB for increases to the RDA limit. Furthermore, Heritage Gas received NSUARB approval for a 6.8 percent increase to its rates effective January 1, 2011. This increase in rates is expected to reduce the RDA.

Inuvik Gas Ltd. & Ikhil Joint Venture

Ikhil produces natural gas for sale under long-term contracts based on the price of diesel fuel. These contracts are with the Northwest Territories Power Corporation and Inuvik Gas. At the end of 2010 Inuvik Gas provided service to 932 (2009 – 905) residential and commercial customers.

Capitalize on Opportunities

The Utility business pursues opportunities to enhance long-term shareholder value and deliver value to its customers. The Utility business' objectives are to:

- Grow its existing infrastructure through infill and expansion of services within current franchise areas;
- Continue the 20-year system rejuvenation program in Alberta to maintain public and worker safety, and to ensure reliable and efficient long-term operation of the gas delivery systems;
- Continue to work within regulatory processes to ensure fair returns are earned for shareholders; and
- Develop or acquire assets in new market areas in Canada and the contiguous United States.

AUI will continue to pursue growth in its existing franchise areas and is well positioned to capture opportunities arising in its service areas. The years leading up to 2008 were of exceptional growth with 2007 and 2008 being the largest growth in-service site additions in AUI's history. New service site installations in the year ended December 31, 2010 were 1,592 compared to 1,241 in the same period in 2009. AltaGas expects that new business growth in 2011 will continue at the historic growth levels of roughly two percent in its Alberta utility business.

2011 will mark the second year of AUI's 20-year system rejuvenation program. The program is being undertaken to maintain public and worker safety and to ensure reliable and efficient long-term operation of AUI's gas delivery systems, many of which are in their fifth or sixth decade of service. In 2011 AUI will continue the system rejuvenation program, including PVC and non certified pipe replacement projects, steel pipe replacement, station upgrades as well as routine system betterment projects.

Heritage Gas offers strong growth potential in its franchise areas such as the continued expansion of its system in the HRM and through ongoing conversion of customers with existing access to natural gas.

In 2010 Heritage Gas expanded service to the Fairview, Clayton Park, Bayer's Lake and Bedford regions of the HRM. Heritage Gas installed nine kilometers of 10 inch steel pipeline, two district regulator stations and 25 kilometers of polyethylene pipeline. The project targets conversions and new developments, with the emphasis on conversions in Fairview, Clayton Park and Bayer's Lake and the older areas of Bedford and construction in the newer areas of Bedford. While most of the capital investment is planned for 2010 and 2011, ongoing construction is expected to bring the new customers serviced by this project to over 1,100 by 2015 from 45 customers at the end of 2010.

AltaGas is actively pursuing the prudent acquisition of other utility type infrastructure and related businesses in Canada and the contiguous United States.

Utility Outlook

AltaGas expects to grow the rate bases within its utility businesses in Alberta and Nova Scotia during 2011 resulting in growth in earnings. AltaGas expects the utilities in Alberta and Nova Scotia to perform according to their respective 2011 GRA. In 2011, AUI is forecast to spend approximately $26 million, growing mid-year rate base by 16 percent to $164 million. Heritage Gas is forecast to spend approximately $20 million to expand its system in 2011 which, along with the growth in the RDA, is expected to grow rate base by 25 percent.

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

AUI is operating in regulatory lag for a number of items including 2011 return on equity, debt rates on all of AUI's debt and its 2010 – 2012 GRA including costs-of-service and capital programs. The 2010 capital incurred and plans for 2011 and 2012 are subject to regulatory approval which is not expected until late 2011 at the earliest. Should AUI receive a decision on any of these matters during the year, the impact of the decision will be recorded in 2011.

Heritage Gas offers strong growth potential in its franchise areas. Examples include the continued expansion of its system in the HRM and ongoing conversion of customers with existing access to natural gas. Heritage Gas expects to activate approximately 750 new customers in 2011.

The 13 percent allowed return on equity and the 8.75 percent allowed debt rate at Heritage Gas are approved by the NSUARB through 2011. Heritage Gas will file a GRA by mid-year 2011 to apply for rates and terms beginning January 2012. The GRA will provide a number of studies requested by the NSUARB, including cost-of-capital, capital structure, cost-of-service and rate-design. The hearing is set for fall 2011 and a decision from the NSUARB is expected before the end of 2011.

Risk Management

AltaGas manages its exposure to risk in the Utility business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
WEATHER	• Earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated • Anticipated volumes are determined based on the 20-year rolling average for weather	• AUI was 1.6 percent warmer than normal in 2010 (2009 – 9.6 percent colder than normal) • Heritage Gas was 13.2 percent warmer than normal in 2010 (2009 – 1.0 percent warmer than normal)
RATE REGULATED ENVIRONMENT	• Skilled regulatory department retained at AUI, Heritage Gas and AltaGas head office • Maintain strong working relationship with the respective regulators and their staff • Use of expert consultants when needed	• Received AUC approval for the issuance of new debt and equity financing at AUI in 2010 • Received NSUARB approval in June 2010 of the $33 million Heritage Gas expansion to Fairview, Clayton Park, Bayer's Lake and Bedford • Completion of the RDA consultation process with NSUARB resulting in a $50 million cap on the Heritage Gas RDA set in September 2010 • Received NSUARB approval of a 6.8 percent increase to Heritage Gas rates effective January 1, 2011 • Alberta 2011 Generic cost-of-capital began in December 2010. Decision expected in late 2011 • Studies to support the Heritage regulatory applications and strategy were underway at the end of 2010, which included cost-of-service and rate design, cost-of-capital, depreciation and lead-lag
RECOVERY OF COSTS AT AUI AND HERITAGE GAS	• Skilled regulatory department retained at AUI, Heritage Gas and the AltaGas head office • Maintain strong working relationship with the respective regulators and their staff	• Received NSUARB approval of a 6.8 percent increase to rates effective January 1, 2011 to recover increased forecast operating costs at Heritage Gas • Filed AUI's 2010 – 2012 GRA, approval expected in late 2011 • Studies to support the recovery of costs undertaken
CONSTRUCTION	• Appropriate internal management structure and processes • Strong project cost control and project management framework • Engage specialists in designing and building major projects	• Practiced effective procurement policies and procedures and vendor selection • AUI successfully completed 118 / 118 planned 2010 system betterment projects in the year and advanced and completed 4 projects from the 2011 system betterment program • Received NSUARB approval of the economic feasibility of the Heritage Gas expansion to Fairview, Clayton Park, Bayer's Lake and Bedford prior to construction of the steel pipe expansion
ENVIRONMENT AND SAFETY	• Strong safety and environmental management systems, which AltaGas continually strives to improve	• AUI did not receive any fines, warnings, or citations related to environmental matters during 2010 • AUI maintained "Partners in Injury Reduction" status as awarded by Alberta Workers' Compensation Board (WCB) • Completion of approximately 93,400 net person hours in 2010 at Heritage Gas without a lost-time injury • Heritage Gas received the Canadian Gas Association Safety Leadership Award for Public Safety Program Excellence in 2010

Consolidated Results

Years ended December 31 ($ millions)	2010	2009	2008
Revenue	1,354.1	1,268.3	1,816.8
Net revenue [1]	485.5	456.6	476.5
EBITDA [1]	243.8	251.5	258.7
EBITDA adjusted for mark-to-market accounting [1]	249.5	242.0	247.7
Operating income [1]	151.8	174.3	188.0
Operating income adjusted for mark-to-market accounting [1]	157.5	164.8	177.0
Net income applicable to common shares	97.2	141.3	163.6
Net income applicable to common shares adjusted for mark-to-market accounting [1]	101.7	132.7	158.0
Total assets	2,751.7	2,628.9	2,132.3
Total long-term liabilities	1,217.4	719.1	851.6
Net additions of capital assets	220.1	486.4	808.0
Distributions declared [2]	87.0	170.2	147.1
Dividends declared [3]	54.1	–	–
Funds from operations [1]	195.0	202.3	216.8

$ per share or unit			
EBITDA [1]	2.99	3.20	3.76
EBITDA adjusted for mark-to-market accounting [1]	3.06	3.08	3.60
Net income – basic	1.19	1.80	2.38
Net income – diluted	1.19	1.79	2.36
Net income applicable to common shares adjusted for mark-to-market accounting [1]	1.25	1.69	2.30
Distributions declared [2]	1.08	2.16	2.125
Dividends declared [3]	0.66	–	–
Funds from operations [1]	2.39	2.58	3.15
Common shares outstanding (millions)			
Weighted average number of common shares outstanding for the year (basic)	81.5	78.5	68.8
End of year (basic)	82.5	80.3	71.9

1 Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of this MD&A.

2 Distributions declared of $0.18 per trust unit and exchangeable unit per month commencing August 2008 through June 2010, $0.175 per unit per month from August 2007 through July 2008.

3 Dividends declared of $0.11 per common share per month commencing July 2010.

2010 CONSOLIDATED FINANCIAL REVIEW

Net income applicable to common shares for 2010 was $97.2 million ($1.19 per share) compared to $141.3 million ($1.80 per share) in 2009. Effective July 1, 2010, AltaGas commenced operations as a corporation, whereby the tax obligations of the organization were expensed. For the first six months of 2010, AltaGas operated under a trust structure, whereby the majority of tax obligations were passed to its securityholders. For purposes of comparison, had AltaGas operated as a trust for all of 2010, net income applicable to common shares for 2010 would have been $118.3 million ($1.45 per share). Adjusting for the impact of mark-to-market accounting, net income applicable to common shares for 2010 was $101.7 million ($1.25 per share) compared to $132.7 million ($1.69 per share) in 2009. Adjusting for the impact of mark-to-market accounting, operating income for all reporting segments for 2010 was $157.5 million compared to $164.8 million in 2009.

Operating income for 2010 from the Gas, Power and Utility businesses was $197.1 million similar to $198.3 million reported in 2009. Results were impacted by the 2009 reduction in liabilities related to natural gas transactions and the reversal of deferred revenue related to the Suffield pipeline reported in 2009. Results were further impacted by lower power prices in Alberta and the impact of lower throughput at some of the processing facilities, partially offset by the addition of the Utility business and Bear Mountain Wind Park, higher frac spreads and lower amortization as a result of change in estimates for the expected remaining useful lives of certain assets. Corporate costs excluding the impact of mark-to-market accounting were $39.5 million in 2010 compared to $33.5 million in 2009. Corporate costs were higher due to a full year of operations in the Utility business, costs associated with conversion to a corporation and general increases.

On a cash flow basis, funds from operations for 2010 was $195.0 million ($2.39 per share) compared to $202.3 million ($2.58 per share) in 2009. The decrease in funds from operations is primarily attributed to lower Alberta power prices and higher interest expense partially offset by the contribution from the full year operations of the Utility business and stronger results in the extraction business. EBITDA adjusted for the impact of mark-to-market accounting was $249.5 million ($3.06 per share) compared to $242.0 million ($3.08 per share) in 2009.

On a consolidated basis, net revenue for 2010 was $485.5 million compared to $456.6 million in 2009. Net revenue from the Gas business increased due to higher realized frac spreads, expiration of a legacy gas marketing contract in late 2009 and higher extraction and transmission operating cost recoveries. These increases were partially offset by lower gas processing fees and volumes processed at some facilities, the reduction in liabilities related to natural gas transactions and the reversal of deferred revenue related to the Suffield pipeline reported in 2009, lower volumes exposed to frac spreads, lower storage margins and a provision for doubtful customer accounts. Net revenue in the Power business decreased due to higher PPA costs and lower realized power prices in Alberta partially offset by contributions from the addition of Bear Mountain Wind Park, addition of the C&I power retail business and higher revenues from the Company's gas-fired peakers. The Corporate segment recorded unrealized losses on risk management contracts and investments compared to unrealized gains last year and no investment income from the Utility Group since it is now fully consolidated due to the acquisition of the shares that were not already owned by AltaGas in fourth quarter 2009. Net revenue in the Utility business increased due to a full year of results since Utility Group and Heritage Gas were acquired during fourth quarter 2009.

Operating and administrative expenses for 2010 were $241.5 million, up from $205.1 million in 2009. The increase was due to incremental costs associated with AltaGas' growth including the addition of the Utility business, higher environmental costs, conversion to a corporation, regulatory compliance initiatives and increases in general administration costs. These increases were partially offset by lower operating costs related to the gas processing business due to lower volumes processed as well as cost control measures.

Accretion for asset retirement obligations for 2010 was $2.9 million compared to $3.1 million in 2009. The decrease was due to the expectation that cash outlays to fund these obligations would be later than originally estimated.

Amortization expense for 2010 was $89.2 million compared to $74.1 million in 2009. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities, partially offset by the adjustment to amortization expense as a result of change in estimates for the expected remaining useful lives of certain assets.

Interest expense for 2010 was $48.8 million compared to $31.8 million in 2009. The increase was due to higher average debt balances of $988.0 million arising from AltaGas' growth compared to $691.5 million in 2009. Interest capitalized in 2010 was $4.4 million compared to $7.1 million in 2009. The average borrowing rate was 5.4 percent in 2010 compared to 5.6 percent in 2009.

Income tax expense for 2010 was $1.7 million compared to $1.2 million in 2009. The increase in expense was primarily associated with higher income subject to tax reported since July 1, 2010 since AltaGas' conversion to a corporation offset by lower taxes incurred by the Utility business and the 2009 nonrecurring tax expense related to an acquisition. For purposes of comparison, had AltaGas operated as a trust for all of 2010, the Company would have reported an income tax recovery of $19.4 million for 2010.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2011 to be approximately $425 million, of which the allocation is expected to be 50 percent for Power, 40 percent for Gas and 10 percent for Utility. To date, approximately $400 million of capital has been committed for 2011.

AltaGas is well positioned to fund its committed capital program through its growing internally generated cash flow, its dividend reinvestment plan and its continued strong access to capital markets. At December 31, 2010 the Company had approximately $775 million of available credit facilities. In 2010 AltaGas declared dividends to common shareholders of approximately 76 percent of funds from operations, after reductions for preferred share dividends and maintenance capital. Based on the new dividend policy on conversion to a corporation on July 1, 2010, the Company expects the payout ratio as a percentage of funds from operations to be in the range of 50 to 55 percent.

The following projects have an expected in-service date after 2011.

Northwest Hydroelectric Projects

AltaGas signed a 60-year CPI indexed EPA with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric power generation project. As disclosed by BC Hydro, the average price contracted is in the range of $120 to $130 per MWh. The Forrest Kerr project is estimated to cost approximately $700 million and is expected to be in commercial operation by mid-2014. Normal course permitting and licensing will occur as construction proceeds. The project is supported by 40 years of hydrologic data and analysis at the Forrest Kerr site.

AltaGas has also entered into an agreement with the Tahltan First Nations providing employment and business opportunities as well as economic participation. In addition, there is an agreement in place for transmission infrastructure with the B.C. government.

Construction is underway, with the construction camp completed. AltaGas expects to obtain the occupancy permit for the camp in March and begin mobilizing the workforce shortly thereafter. The turbine package and initial tunnel excavation contracts for the access and surge tunnels are expected to be awarded by the end of first quarter 2011. Tunneling of the surge and powerhouse access tunnels is expected to begin in March 2011 with completion of the tunnels expected in third quarter 2011. At the close of 2010, approximately 20 percent of the cost of the project had been fixed. AltaGas expects to have 75 percent of the project cost contractually committed to fixed price contracts by December 31, 2011 and 90 percent contractually fixed by the end of 2012. AltaGas' plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

AltaGas continues to be in discussions related to the McLymont Creek and Volcano Creek projects. These two projects will add 82 MW of run-of-river hydroelectric power to the region.

Harmattan Co-stream Project

On December 8, 2010, AltaGas' application for the Harmattan Co-stream Project received approval from the Energy Resources Conservation Board (ERCB). The project is expected to cost approximately $130 million and includes an incremental $8 million for an enhanced refrigeration modernization project. The Harmattan Co-stream project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western System to be processed using spare capacity at the Harmattan Complex to recover ethane and other NGLs. AltaGas expects to commence construction in early 2011 and to commence operations in first quarter 2012. Based on current capital cost estimates AltaGas expects the annual EBITDA contribution to be in the range of $20 million to $25 million once completed.

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

AltaGas expects to procure materials and services in first quarter 2011 and begin pipeline construction in June 2011. Major equipment tie in is planned to occur during the planned plant turnaround in September 2011. To date approximately $15 million of costs are fixed. AltaGas expects a further $50 million to be fixed by April 2011 and another $15 million to be contractually fixed by third quarter 2011. In total, AltaGas expects approximately 60 percent of the total project cost to be contractually fixed. The remainder will be subject to cost escalation and labour productivity risk. AltaGas plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

In early January 2011, the parties that initially intervened in AltaGas' application filed a notice of motion for leave to appeal. AltaGas believes that the grounds set forth for leave to appeal are without merit and remains committed to the schedule as outlined above.

Gordondale Gas Plant Project

On November 4, 2010 AltaGas announced it will construct a 120 Mmcf/d gas processing facility and an associated gas gathering system in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The project is subject to regulatory approval. The plant will also be equipped with liquids extraction facilities. The facility and associated gas gathering system is expected to cost approximately $235 million and be in-service in late 2012. By using existing infrastructure in the area and building the Henderson Pipeline to connect to the Pouce Coupe facility, AltaGas expects to provide processing services for early production by mid-2011. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility. Based on current production and natural gas reserve estimates, AltaGas expects the annual average EBITDA contribution to range between $30 million and $35 million once completed.

The project is subject to regulatory approval by Alberta Environment (AENV) and ERCB. AltaGas has filed the AENV application and expects to file the regulatory application with the ERCB in first quarter 2011. Based on the expected timeline for filing and receiving regulatory approvals, the Company expects $70 million to $80 million of costs to be contractually fixed by

September 2011. In total, approximately two-thirds of costs are expected to be contractually fixed over the course of construction. The remainder will be subject to cost escalation and labour productivity risk. AltaGas plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

Harmattan Cogeneration #2 Project

Following on the success of the 15 MW Harmattan Cogeneration project that was commissioned in late 2010, AltaGas plans to construct a second 15 MW cogeneration unit at the Harmattan Plant as a means of supplying power for the Co-stream project. Having two independent generating units on site will provide a reliable source of low-cost power and steam to the facility while reducing the Harmattan facility's reliance on the grid and its power boilers. The project also includes adding the distribution system within the Harmattan facility. The project is estimated to cost $24 million and be in-service at the same time as the Harmattan Co-stream Project comes on line.

Alton Natural Gas Storage Project

AltaGas completed the acquisition of Landis Energy Corporation in first quarter 2010. The most advanced project under development by Landis is the Alton Natural Gas Storage Project, of which AltaGas has a 50 percent interest, located near Truro, Nova Scotia that is expected to serve customers seeking to manage natural gas supply requirements in eastern Canada and the northeast United States. The Alton project has the potential capacity of 10 Bcf of natural gas storage.

Wind-generation Power Projects

The 67 MW Walker Ridge project in northern California is currently under development. AltaGas has selected the turbines and a preliminary layout and has completed preliminary engineering studies. The project is located near existing transmission lines and requires limited system upgrades to interconnect. It is located in Lake and Colusa counties, close to San Francisco load. This project is proceeding with the environmental permitting process. AltaGas is actively seeking bilateral agreements for sale of the power output.

The 100 MW Glenridge project in southeast Alberta is currently under development. AltaGas has secured a 17,000 acre land package. AltaGas is in the third stage of the Alberta Electricity System Operator (AESO) customer connection process and has begun the facilities study. AltaGas is actively seeking a market for its prospective green credits. Once in-service, the project will use these green credits to offset compliance costs associated with AltaGas' Sundance B PPAs.

The 90 MW Roughrider project in North Dakota is currently under development. The project holds easements of approximately 27,000 acres on private land. AltaGas is currently in the Western Area Power Administration (WAPA) and Midwest Independent System Operator (ISO) transmission queues and has determined that there are limited transmission upgrades required to interconnect to the WAPA transmission system. AltaGas is seeking green credit and energy markets with local and out of state utilities.

Sparwood Power Project

AltaGas is pursing the installation of a 6 MW waste heat recovery unit in Sparwood, B.C. The project is supported by a 20-year EPA with BC Hydro. Right of way and waste heat agreement discussions are underway with relevant parties and AltaGas expects to commence construction in 2011.

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger results from its operating businesses in 2011 compared to 2010. On a net income basis, the Company expects to report higher future income tax expense based on being a corporation for a full year, partially offset by a lower effective corporate tax rate of approximately 23 percent. With tax pools in excess of $1 billion, AltaGas does not expect to be cash taxable until approximately 2016. However, net income before taxes is expected to be higher in 2011 compared to 2010 due to stronger results from its diversified portfolio of energy assets.

Higher earnings are expected from higher volumes processed at some field and extraction facilities driven by producer activity to capitalize on high NGL content gas plays or light oil plays. Stronger results are expected in gas despite turnarounds at the Younger Extraction Plant and Harmattan Complex and lower daily take-or-pay volumes on the Suffield natural gas transmission system. The Gas business is also expected to benefit from continued strong frac spreads on volumes exposed to spot NGL prices.

Recent supply uncertainty in the Alberta power market together with changes to the Rate Regulated Option used for setting power prices by the utilities has increased power prices and power price volatility. With approximately two-thirds of generation hedged in first quarter 2011 at an average price of $63.50 and approximately one-third hedged at $64.50 for the rest of the year and recent increases in forward power prices, AltaGas expects earnings in its power business to be at or slightly lower than the 2010 results. The addition of the new Harmattan Cogeneration facility and the gas-fired peakers are all expected to benefit from higher power prices in 2011.

AltaGas also expects to report stronger earnings from its Utility business as the utilities in Alberta and Nova Scotia continue to increase rate base at 16 percent and 25 percent respectively in 2011.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (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. All of the measures have been calculated to be consistent with previous disclosures. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and its capacity to fund dividends, capital expenditures and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to net revenue, operating income, operating income adjusted for mark-to-market accounting, EBITDA, EBITDA adjusted for mark-to-market accounting, net income applicable to common shares adjusted for mark-to-market accounting and funds from operations throughout this document have the meanings as set out in this section.

Net Revenue

Years ended December 31 ($ millions)	2010	2009	2008
Net revenue	485.5	456.6	476.5
Add: Cost of sales	868.6	811.7	1,340.3
Revenue (GAAP financial measure)	1,354.1	1,268.3	1,816.8

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

Operating Income

Years ended December 31 ($ millions)	2010	2009	2008
Operating income	151.8	174.3	188.0
Add (deduct):			
Interest expense	(48.8)	(31.8)	(27.4)
Foreign exchange (loss) gain	(0.1)	–	1.4
Income taxes (expense) recovery	(1.7)	(1.2)	1.6
Preferred shares dividend (net of tax)	(4.0)	–	–
Net income applicable to common shares (GAAP financial measure)	97.2	141.3	163.6

Operating income is a measure of AltaGas' profitability from its principal business activities prior to how these activities are financed or how the results are taxed. The measure is used by management to assess the operating performance of the business segments since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income and is defined as net revenue less operating and administrative expenses, amortization and accretion of asset retirement obligations.

Operating Income Adjusted for Mark-to-Market Accounting

Years ended December 31 ($ millions)	2010	2009	2008
Operating income before unrealized (loss) gain on mark-to-market accounting	157.5	164.8	177.0
Add (deduct):			
Unrealized (loss) gain on mark-to-market accounting	(5.7)	9.5	11.0
Interest expense	(48.8)	(31.8)	(27.4)
Foreign exchange (loss) gain	(0.1)	–	1.4
Income taxes (expense) recovery	(1.7)	(1.2)	1.6
Preferred share dividends (net of tax)	(4.0)	–	–
Net income applicable to common shares (GAAP financial measure)	97.2	141.3	163.6

Operating income adjusted for mark-to-market accounting 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 and investments. The measure is used by management to assess the operating performance of the business segments since it is a better indicator of operating performance than net income. Operating income adjusted for mark-to-market accounting is calculated from the Consolidated Statements of Income and is defined as net revenue less operating and administrative expenses and amortization less any unrealized gains or losses on risk management contracts and investments.

EBITDA

Years ended December 31 ($ millions)	2010	2009	2008
EBITDA	**243.8**	251.5	258.7
Add (deduct):			
Amortization	**(89.2)**	(74.1)	(67.0)
Accretion of asset retirement obligations	**(2.9)**	(3.1)	(2.3)
Interest expense	**(48.8)**	(31.8)	(27.4)
Income taxes (expense) recovery	**(1.7)**	(1.2)	1.6
Preferred share dividends (net of tax)	**(4.0)**	–	–
Net income applicable to common shares (GAAP financial measure)	**97.2**	141.3	163.6

EBITDA is a measure of AltaGas' operating profitability. EBITDA provides an indication of the results generated by principal business activities prior to accounting for how these activities are financed, assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and is defined as net revenue less operating and administrative expenses, and foreign exchange gains or losses.

EBITDA Adjusted for Mark-to-Market Accounting

Years ended December 31 ($ millions)	2010	2009	2008
EBITDA	**249.5**	242.0	247.7
Add (deduct):			
Unrealized (loss) gain on mark-to-market accounting	**(5.7)**	9.5	11.0
Amortization	**(89.2)**	(74.1)	(67.0)
Accretion of asset retirement obligations	**(2.9)**	(3.1)	(2.3)
Interest expense	**(48.8)**	(31.8)	(27.4)
Income taxes (expense) recovery	**(1.7)**	(1.2)	1.6
Preferred share dividends (net of tax)	**(4.0)**	–	–
Net income applicable to common shares (GAAP financial measure)	**97.2**	141.3	163.6

EBITDA adjusted for mark-to-market accounting is a measure of AltaGas' operating profitability without the impact of the change in fair value of risk management contracts and the mark-to-market on investments. EBITDA adjusted for mark-to-market accounting reports the results of business activities on a realized basis and prior to how business activities are financed, assets are amortized or how the results 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 and investing activities. EBITDA adjusted for mark-to-market accounting is calculated from the Consolidated Statements of Income and is defined as net revenue adjusted for unrealized gains or losses on risk management contracts and investments less operating and administrative expenses, and foreign exchange gains or losses.

Net Income Applicable to Common Shares Adjusted for Mark-to-Market Accounting

Years ended December 31 ($ millions)	2010	2009	2008
Net income applicable to common shares before mark-to-market accounting	**101.7**	132.7	158.0
Add (deduct):			
Unrealized (loss) gain on mark-to-market accounting	**(4.5)**	8.6	5.6
Net income applicable to common shares (GAAP financial measure)	**97.2**	141.3	163.6

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

Funds From Operations

Years ended December 31 ($ millions)	**2010**	2009	2008
Funds from operations	**195.0**	202.3	216.8
Deduct:			
Net change in non-cash working capital	**(1.9)**	(17.8)	(10.9)
Asset retirement obligations settled	**(0.5)**	(0.4)	(0.7)
Cash from operations (GAAP financial measure)	**192.6**	184.1	205.2

Funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash from operations, or other cash flow measures calculated in accordance with GAAP. Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement obligations.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income

Years ended December 31 ($ millions)	**2010**	2009
Gas	**95.9**	102.9
Power	**76.4**	88.0
Utility	**24.8**	7.4
Sub total: Operating Businesses	**197.1**	198.3
Corporate	**(45.3)**	(24.0)
	151.8	174.3

GAS

2010 Financial Results

Operating income from the Gas reporting segment for 2010 was $95.9 million compared to $102.9 million in 2009. In 2010, approximately 93 percent (2009 – 86 percent) was contributed by the E&T business. The FG&P business contributed approximately 6 percent (2009 – 6 percent), with the remainder contributed by the Energy Services (ES) business. Operating income decreased due to non recurring adjustments to liabilities related to natural gas transactions, lower volumes processed at some extraction and FG&P facilities and the reversal of deferred revenue related to the Suffield pipeline reported in 2009. Operating income was also impacted by the movement of C&I power retail business to the Power reporting segment and increased provision for doubtful customer accounts. These decreases were partially offset by higher realized frac spread, the expiration of a legacy gas marketing contract in fourth quarter 2009, which resulted in losses in previous quarters, lower amortization as a result of change in estimates for the expected remaining useful lives for certain facilities, and lower operating and administrative expenses at some of the processing facilities.

Net revenue in the Gas reporting segment for 2010 was $312.7 million compared to $327.1 million in 2009. Net revenue decreased due to a non recurring $9.4 million adjustment to liabilities related to natural gas transactions reported in 2009, $5.4 million decrease in FG&P fee for service revenues and volumes processed, $3.3 million decrease due to the reversal of Suffield revenue deferral in third quarter 2009, $3.6 million of C&I power retail sales revenues moved to the Power reporting segment, $2.4 million from lower extraction volumes and $1.0 million incremental provision for doubtful customer accounts. These increases were partially offset by $5.2 million from higher realized frac spreads and $4.7 million due to the expiration of a legacy gas marketing contract.

Operating and administrative expense for 2010 was $154.8 million compared to $159.9 million in 2009. The decrease was largely due to lower volumes at certain gas processing and extraction facilities and cost saving measures implemented, partially offset by costs associated with assets that were added or expanded during the year.

Amortization expense for 2010 was $59.1 million compared to $61.3 million in 2009. Accretion expense for 2010 was $2.8 million compared to $3.1 million in 2009. The decreases were due to revisions in estimates in the lives of certain facilities partially offset by the impact of growth in AltaGas' asset base from construction activities.

Gas Operating Statistics

Years ended December 31	2010	2009
E&T		
Extraction inlet gas processed (Mmcf/d) [1]	798	841
Extraction ethane volumes (Bbls/d) [1]	25,453	26,817
Extraction NGL volumes (Bbls/d) [1]	12,654	13,236
Total Extraction volumes (Bbls/d) [1]	38,107	40,053
Frac spread – realized ($/Bbl) [1, 2]	27.27	23.46
Frac spread – average spot price ($/Bbl) [1]	31.95	19.51
Transmission volumes (Mmcf/d) [1, 3]	286	324
FG&P		
Processing throughput (gross Mmcf/d) [1]	423	453
Capacity utilization (%) [4]	35	39
Energy Services		
Average volumes transacted (GJ/d) [5]	386,004	354,513

1 Average for the period.
2 Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.
3 Excludes NGL pipeline volumes.
4 As at the end of the reporting period.
5 Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments, and volumes sold in gas exchange transactions.

Average ethane and NGL volumes in the extraction business decreased by 1,364 Bbls/d and 582 Bbls/d, respectively, in 2010 compared to 2009. Volumes declined largely due to lower gas supply at the Empress extraction facilities as a result of declining exports of natural gas east of Alberta. These decreases were partially offset by slightly higher inlet volumes and NGL yields at the Joffre facility and higher NGL processing at Harmattan. Natural gas volumes transported in the transmission business in 2010 decreased from 2009 primarily due to lower volumes moved on the Suffield system. However, in the transmission business, pipeline throughput has minimal impact on the financial results due to cost-of-service and take-or-pay contractual arrangements in place.

In FG&P, throughput in 2010 averaged 423 Mmcf/d compared to 453 Mmcf/d in 2009. Although certain areas have experienced volume growth, the lack of producer activity in 2009 and 2010 in response to low natural gas prices has resulted in overall lower processing volumes.

POWER

2010 Financial Results

Operating income in the Power Segment in 2010 was $76.4 million compared to $88.0 million in 2009. Operating income decreased primarily as a result of lower realized power prices, higher PPA costs and higher environmental costs. The decreases were partially offset by the addition of Bear Mountain Wind Park, and contributions from the Alberta commercial and industrial power retail business.

Net revenue for 2010 was $101.8 million compared to $102.2 million for 2009. Net revenue decreased due to the $7.6 million impact of lower realized power prices, $5.6 million due to higher PPA costs and $3.9 million from higher environmental costs included as a reduction of revenue. These decreases were partially offset by $9.7 million from Bear Mountain Wind Park, $3.6 million from the C&I power retail business, $2.1 million higher contribution from gas-fired peaking plants and commencement of operations at the Harmattan cogeneration plant.

Operating and administrative expense was $10.0 million for 2010 compared to $6.1 million for 2009. The increase was due to costs related to the development of renewable energy projects, the addition of the commercial and industrial power retail business, and the commencement of commercial operations at Bear Mountain Wind Park in fourth quarter 2009.

Amortization expense was $15.3 million in 2010 compared to $8.2 million in 2009. The increase was largely due to the addition of Bear Mountain Wind Park.

Power Operating Statistics

Years ended December 31	2010	2009
Volume of power sold (GWh) [1]	**2,828**	2,725
Average price realized on the sale of power ($/MWh) [1]	**66.79**	68.97
Alberta Power Pool average spot price ($/MWh) [2]	**50.76**	47.84

1 Average for the period.
2 Includes only Alberta volumes and prices realized on the sale of power.

Bear Mountain wind volumes were below historical averages in 2010. The EBITDA impact of the weaker wind in 2010 was approximately $7.8 million compared to expectations. A portion of 2010 green attributes associated with Bear Mountain was sold in a transaction completed in 2009 at prices inline with management's expectations.

UTILITY
Financial Results

Years ended December 31	2010	2009
Operating income	**24.8**	7.4
Net income	**16.7**	5.4

2010 Financial Results

The Utility business commenced operations with the acquisition of Utility Group on October 8, 2009 and the remaining 75.1 percent of Heritage Gas on November 18, 2009. The results of the Utility reporting segment are highly seasonal resulting in strong first and fourth quarter results and weaker second and third quarter results due to the majority of natural gas deliveries occurring during the winter heating season. For 2010 the Utility reporting segment recorded $24.8 million in operating income compared to $7.4 million in 2009.

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

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

Net income from the Utility reporting segment was $16.7 million in 2010 compared to $5.4 million in 2009, primarily due to AltaGas owning Utility Group and all of Heritage Gas for a full year compared to only twelve and six weeks respectively in 2009. The Utility business grew its rate base by 15 percent in 2010 to $277.0 million which increased net income by $1.8 million on a full year basis. Warmer than normal weather in both Alberta and Nova Scotia reduced 2010 net income by $0.7 million on a full year basis.

After deducting natural gas costs of $79.8 million (2009 – $30.5 million) net revenue reported by the Utility business grew to $71.9 million (2009 – $13.0 million). The increase in 2010 net revenue was primarily due to the full year impact of AltaGas' acquisitions of Utility Group and the 75.1 percent of Heritage Gas it did not already own, on October 8, 2009 and November 18, 2009, respectively. Net revenue growth of $1.9 million from the higher 2010 rate base was partially offset by warmer than normal weather in Alberta and Nova Scotia which decreased net revenue by $0.8 million.

Operating and administrative expense increased from $3.4 million in 2009 to $35.5 million in 2010. Depreciation, depletion and amortization expense increased from $2.2 million in 2009 to $11.6 million in 2010. Interest expense increased from $1.0 million in 2009 to $7.7 million in 2010. Income tax decreased from $1.0 million in 2009 to $0.4 million in 2010. The increased expenses were primarily a result of the late 2009 acquisitions of Utility Group and Heritage Gas.

Utility Operating Statistics

Years ended December 31	2010	2009[1]
Natural gas deliveries - end-use (PJ)[2]	19.9	6.6
Natural gas deliveries - transportation (PJ)[2]	5.3	0.6
Service sites at year-end[3]	74,664	72,717
AUI Degree day variance (%)[4]	(1.6)	9.9
Heritage Gas Degree day variance (%)[4]	(13.2)	(1.0)

1 Reflect acquisitions of Utility Group as of October 8, 2009 and Heritage Gas as of November 18, 2009, after which dates AltaGas owns 100% of both companies.
2 Petajoule (PJ) is one million gigajoules (GJ).
3 Service sites reflect all of the service sites of AUI, Heritage Gas and Inuvik Gas.
4 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.

CORPORATE

Description of Corporate Assets

The Corporate reporting segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity and return on capital without the impact of the volatility in commodity prices, interest rates and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity since risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate reporting segment.

2010 Financial Results

The operating loss for 2010 was $45.3 million compared to $24.0 million for 2009. The increased loss was due to unrealized losses on investments of $4.3 million compared to gains of $5.8 million last year, unrealized losses from risk management contracts of $1.3 million compared to gains of $3.7 million in the prior year, investment income for 2010 of $7.1 million compared to $10.3 million in 2009 and higher administration expenses related to AltaGas' growth, conversion to a corporation and costs to comply with regulatory requirements.

Net revenue was $1.6 million in 2010 compared to $18.6 million in 2009. Net revenue decreased due to the $10.1 million difference between mark-to-market losses on investments reported in the current year compared to unrealized gains in the prior year, $5.0 million due to unrealized losses on risk management contracts compared to gains in the prior year and lower investment income of $1.9 million.

Operating and administrative expense was $43.7 million in 2010 compared to $40.1 million in 2009. Increased expenses were incurred to support the conversion to a corporation, regulatory requirements and growth of the Company partially offset by several initiatives to reduce general and administrative expenses.

Amortization expense was $3.1 million in 2010 compared to $2.5 million in 2009. The increase was primarily due to the deployment of information systems to support the growth of the Company.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2011 is expected to be lower than the loss reported in 2010. During 2010, the Company incurred costs to convert from a trust structure to a corporation and support activities related to compliance with the Harmonized Sales Tax in Ontario and British Columbia. The Company expects to incur costs to transition to IFRS or US GAAP during 2011 based on the outcome of management's decision to be finalized during the first quarter of 2011. The Corporate reporting segment is also expected to report lower income from other investments during 2011.

The Company expects to report higher future income tax expense based on being a corporation for a full year, partially offset by a lower effective corporate tax rate of approximately 23 percent. The tax rate at the consolidated level is lower than the expected statutory rate as a result of the lower effective tax rate at the Utility business. Taxes recoverable or payable by the Utility businesses are recorded as regulatory assets or liabilities until such time as the taxes are collectible or payable from or to the utility customers. With tax pools in excess of $1 billion, AltaGas does not expect to be cash taxable until approximately 2016.

The effects of risk management contracts are based on estimates relating to commodity prices, interest rates and foreign exchange rates over time. The actual amounts will vary based on these drivers, and management is therefore unable to predict the impact of financial instruments on 2011 results. However, the impact of the accounting standards is expected to be relatively low since AltaGas uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked in margins. AltaGas does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2010, AltaGas acquired capital assets, long-term investments and other assets for $226.5 million compared to $499.2 million in 2009.

Net Invested Capital – Investment Type

Year ended December 31, 2010 ($ millions)	Gas	Power	Utility	Corporate	Total
Invested capital:					
Capital assets	108.2	51.4	56.6	6.1	222.3
Long-term investments and other assets	–	(0.1)	0.5	3.8	4.2
	108.2	51.3	57.1	9.9	226.5
Disposals:					
Capital assets	–	–	(1.9)	(0.3)	(2.2)
Long-term investment and other assets	–	–	(2.4)	–	(2.4)
Net invested capital	108.2	51.3	52.8	9.6	221.9

Net Invested Capital – Investment Type

Year ended December 31, 2009 ($ millions)	Gas	Power	Utility	Corporate	Total
Invested capital:					
Capital assets	52.6	160.3	271.4	3.2	487.5
Long-term investments and other assets	–	(0.4)	(12.3)	24.4	11.7
	52.6	159.9	259.1	27.6	499.2
Disposals:					
Capital assets	(0.2)	(0.7)	–	(0.1)	(1.0)
Net invested capital	52.4	159.2	259.1	27.5	498.2

AltaGas categorizes its invested capital into maintenance, growth and administration. Growth capital of $212.9 million was expended in 2010 (2009 – $490.1 million). In the Gas business, growth capital was mainly attributed to $33.1 million for acquisition of Landis, the investment in the Groundbirch Gas Plant and its gas gathering system for $28.0 million, $5.2 million for Gordondale Gas Plant development and construction, $22.4 million for Pouce Coupe sour gas facilities, $7 million for Ante Creek expansion, $2.8 million for Acme expansion, $1.3 million for Harmattan CO2 enrichment project, $1.7 million for Younger Spur Project, $2.0 million for Harmattan Co-stream Project, and $1.2 million for various gas projects. Within the Power reporting segment, growth capital projects comprised $33.4 million for renewable hydro projects, $12.7 million for Harmattan Cogeneration Project and $2.7 million for various wind projects. Within the Utility reporting segment, net capital invested of $56.6 million (2009 – $259.1 million) mainly included $25.5 million at AUI including the first year of the 20-year system rejuvenation program, $31.0 million at Heritage Gas including the expansion of the distribution system to serve the Fairview, Clayton Park, Bayer's Lake and Bedford Region of the HRM, and $0.1 million at Ikhil. The growth capital of $259.1 in 2009 mainly comprised the acquisition costs of Utility Group and Heritage Gas. The Corporate reporting segment growth capital of $2.8 million was mainly related to the acquisition of additional shares of Magma Energy Corporation. Administrative and maintenance capital expenditures in 2010 were $8.1 million and $5.5 million, respectively (2009 – $5.8 million and $3.3 million, respectively).

Invested Capital – Use

Year ended December 31, 2010 ($ millions)	Gas	Power	Utility	Corporate	Total
Invested capital:					
Maintenance	2.5	2.5	0.5	–	5.5
Growth	104.7	48.8	56.6	2.8	212.9
Administrative	1.0	–	–	7.1	8.1
Invested capital	108.2	51.3	57.1	9.9	226.5

Invested Capital – Use

Year ended December 31, 2009 ($ millions)	Gas	Power	Utility	Corporate	Total
Invested capital:					
Maintenance	3.3	–	–	–	3.3
Growth	49.1	159.9	259.1	22.0	490.1
Administrative	0.2	–	–	5.6	5.8
Invested capital	52.6	159.9	259.1	27.6	499.2

FINANCIAL INSTRUMENTS

The Company 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 2010, the Company had positions in the following types of derivatives, which are also disclosed in note 15 to the Consolidated Financial Statements:

- Commodity forward contracts: The Company executes gas, power and other commodity forward contracts to manage its asset portfolio and lock-in margins from back to back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services business transacts primarily on this basis;

- Commodity swap contracts: AltaGas executes fixed for floating power price swaps to manage its power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power business' results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.00/MWh to $999.99/MWh in 2010 and $0.10/MWh to $999.99/MWh in 2009. The average Alberta spot price was $50.76/MWh in 2010 (2009 – $47.84/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 $66.79/MWh in 2010 (2009 – $68.97/MWh). In 2011, approximately 40 percent of Alberta-based power is hedged at a price of $64.50 MWh;

- NGL frac spread hedges: The Company executes fixed for floating NGL frac spread swaps to manage its NGL frac spreads. The E&T business' results are affected by fluctuations in NGL frac spreads. During the year, the Company had NGL frac spread agreements for an average of 2,917 Bbls/d at an average price of approximately $21.62/Bbl. The average spot NGL frac spread for 2010 was $31.95/Bbl (2009 – $19.51/Bbl). The average NGL frac spread realized in 2010 was $27.27/Bbl (2009 – $23.46/Bbl). The Company has hedged an average of 3,625 Bbls/d, or approximately 70 percent of volumes that are exposed to spot prices for 2011, at a price of approximately $26.85/Bbl;

- Interest rate forward contracts: The Company enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2010 the Company had interest rate swaps for $80 million with varying terms to maturity until March 31, 2012. At December 31, 2010, the Company had fixed the interest rate of 96 percent of its debt including MTNs and capital leases; and

- 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.

The Company 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. The various financing initiatives completed in 2010 are indications of AltaGas' strong financial position and access to capital markets.

Cash Flows

Years ended December 31 ($ millions)	2010	2009
Cash from operations	192.6	184.1
Investing activities	(161.9)	(464.1)
Financing activities	(32.2)	265.2
Change in cash	(1.5)	(14.8)

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $192.6 million in 2010 compared to $184.1 million in 2009. The increase in cash from operations was mainly the result of a positive net change in non-cash working capital since the end of 2009.

Working Capital

Years ended December 31 ($ millions except current ratio)	2010	2009
Current assets	304.0	331.7
Current liabilities	323.3	861.0
Working capital	(19.3)	(529.3)
Current ratio	0.94	0.39

Working capital was in a deficit position $19.3 million at December 31, 2010 compared to a deficit of $529.3 million at December 31, 2009. The working capital ratio was 0.94 at the end of 2010 compared to 0.39 at the end of 2009. The change was mainly due to credit facilities that were classified as current prior their refinancing in 2010 on a long-term basis.

Investing Activities

Cash used for investing activities in 2010 was $161.9 million compared to $464.1 million in 2009. Cash used for investing activities was lower in 2010 due to lower capital expenditures and acquisition of long-term investments, as well as cash received from disposition of short-term investments.

Financing Activities

Cash used for financing activities was $32.2 million in 2010 compared to cash obtained from financing activities of $265.2 million in 2009. The increased use of cash was due to repayment of long-term and short-term debts during 2010 and no public offering of common equity unlike 2009, which was partially offset by the proceeds from the 2010 preferred share offering and lower dividends paid.

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 operating businesses. At December 31, 2010 AltaGas had total debt outstanding of $904.5 million, down from $1,014.6 million as at December 31, 2009. At December 31, 2010 AltaGas had $775 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 $951.6 million. At December 31, 2010 AltaGas had drawn bank debt of $119.5 million against the Utility Group revolving credit facility and the demand operating facilities. And at December 31, 2010, AltaGas had letters of credit outstanding of $53.5 million against the extendible revolving letter of credit facility, the syndicated revolving credit facility, and the demand operating facilities.

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. AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2010 was 2.9 times.

On March 25, 2010, AltaGas issued $200 million of senior unsecured medium term notes which carry a coupon rate of 5.49 percent and mature on March 27, 2017.

On June 30, 2010 AltaGas entered into a new three year $600 million extendible unsecured revolving term credit facility with a syndicate of nine banks. The new 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 was used to retire and replace the previously held $150 million and $375 million credit facilities which matured in August and September 2010, respectively. 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.

On July 15, 2010 AltaGas filed a Short Form Base Shelf Prospectus to facilitate the issuance of common shares, preferred shares or unsecured debt securities. This shelf has a life of 25 months and permits AltaGas to issue up to an aggregate of $1 billion of securities. On August 11, 2010 AltaGas filed a prospectus supplement to the Short Form Base Shelf Prospectus dated July 15, 2010. The supplement establishes AltaGas' preferred share program. On November 22, 2010 AltaGas filed a prospectus supplement to the Short Form Base Shelf Prospectus dated July 15, 2010. The supplement establishes AltaGas' MTN program and allows AltaGas to access the Canadian MTN market when appropriate. As of December 31, 2010, under this Short Form Base Shelf Prospectus, AltaGas has utilized approximately $375 million of the original $1 billion available.

On August 19, 2010, AltaGas issued 8,000,000 Series A Preferred Shares for aggregate gross proceeds of $200 million to a syndicate of underwriters. The Series A Preferred Shares pay a cumulative quarterly fixed dividend for the initial period ending September 30, 2015 at an annual rate of 5.00 percent. The dividend rate will reset on September 30, 2015 and on September 30 of every fifth year thereafter. Net proceeds were used to reduce outstanding indebtedness under AltaGas' credit facilities.

On November 17, 2010, AltaGas restated and amended the Utility Group's maturing $130 million unsecured extendible revolving credit facility. The Utility Group's unsecured extendible revolving credit facility with a syndicate of five banks was increased to $200 million and its term was extended by three years to mature on November 17, 2013.

On November 26, 2010, AltaGas issued $175 million of senior unsecured medium term notes which carry a coupon rate of 4.6 percent and mature on January 15, 2018. The net proceeds resulting from the issuance of notes were used by AltaGas to reduce outstanding bank indebtedness and for general corporate purposes

Credit Facilities

($ millions)	Borrowing capacity	**Drawn at December 31 2010**[4]	Drawn at December 31 2009
Demand operating facilities	76.6	**7.9**	16.3
Extendible revolving letter of credit facility	75.0	**50.5**	56.7
Syndicated revolving credit facility [1]	–	**–**	350.8
Syndicated revolving credit facility [2]	600.0	**–**	–
Utility Group revolving credit facility [3]	200.0	**114.5**	130.0
	951.6	**172.9**	553.8

1 Revolving credit facility cancelled on June 30, 2010.
2 Revolving credit facility maturing June 30, 2013.
3 Revolving credit facility maturing November 17, 2013.
4 Include letter of credit outstanding of $53.5 million as at December 31, 2010.

At December 31, 2010 AltaGas held a $75.0 million (December 31, 2009 – $75.0 million) unsecured three year extendible revolving letter of credit facility with two Canadian chartered banks maturing on June 30, 2013. AltaGas may also borrow by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2010 AltaGas had letters of credit of $50.5 million (December 31, 2009 – $46.7 million) outstanding against the extendible revolving letter of credit facility and $3.0 million letters of credit (December 31, 2009 – $5.1 million) outstanding against the demand operating facilities and the syndicated revolving credit facility.

CONTRACTUAL OBLIGATIONS

December 31, 2010		Payments due by period			
($ millions)	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Long-term debt	888.9	–	410.0	3.9	475.0
Capital leases	6.1	1.5	3.4	1.2	–
Operating leases	15.3	5.3	8.6	1.4	–
Purchase obligation	73.2	4.0	8.1	8.8	52.3
Capital project commitments [1]	113.2	43.0	70.2	–	–
Total contractual obligations	1,096.7	53.8	500.3	15.3	527.3

1 Capital project commitments are related to the construction costs of the Forrest Kerr run-of-river hydroelectric project and assorted Gas business projects. Amounts are estimates and are subject to variability depending on actual construction costs.

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2010 was $6.1 million (December 31, 2009 – $7.5 million) with the balance due in monthly payments comprising principal and interest of $0.2 million.

AltaGas has long-term operating lease agreements for gas storage, office space, office equipment and automotive equipment.

RELATED PARTIES

AltaGas pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by an employee. Payments of approximately $0.1 million were made in 2010 (2009 – approximately $0.1 million) which is the exchange value of the property agreed to by both parties. The lease expires December 2011.

As of October 8, 2009, AltaGas owned 100 percent of the shares of Utility Group. Therefore, commencing fourth quarter 2009, the Utility Group is not considered a related party. During the first three quarters of 2009, AltaGas sold $39.0 million of natural gas to, and incurred transportation costs of $0.1 million charged by, Utility Group as part of AltaGas' normal course of business. AltaGas also paid management fees of $0.1 million to, and received management fees of $0.1 million, from Utility Group for administrative services. In addition, AltaGas provided $0.1 million of operating services to Utility Group. The measurement of transactions between AltaGas and Utility Group is exchange value, to which both parties have agreed. AltaGas held significant influence over Utility Group given AltaGas' 19.8 percent ownership, and AltaGas' Chairman and Chief Executive Officer was a director of Utility Group prior to the October 8, 2009 acquisition.

RATING AGENCIES

On August 10, 2010, S&P and DBRS Limited (DBRS) commenced rating of the Series A Preferred Shares with an S&P rating of P-3H and DBRS rating of Pfd-3.

On October 16, 2009, DBRS raised its rating for AltaGas from BBB (low) with a Positive trend to BBB with a Stable trend. DBRS has cited the Utility Group acquisition as improving AltaGas' business risk profile through the addition of low-risk, regulated natural gas distribution assets in Alberta, Nova Scotia and the Northwest Territories.

On April 21, 2009 Standard & Poor's (S&P) upgraded its rating for AltaGas from BBB to BBB with a Stable outlook. S&P cited AltaGas' increased exposure to long-term contracted gas infrastructure business, prudent financial practices and effective strategy execution for the rating upgrade.

A Pfd-3 rating by DBRS is the third highest of six categories granted by DBRS. According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adversities present which detract from debt protection. Pfd-3 ratings normally correspond with companies whose bonds are rated in the higher end of the BBB category. “High” or “low” grades are used to indicate the relative standing within a rating category. The absence of either a “high” or “low” designation indicates the rating is in the middle of the category.

A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non payment than other speculative issues. However, it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor’s inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by “high” and “low” grades which indicate relative standing within the major rating categories.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Except as set forth above, neither DBRS nor S&P has announced that it is reviewing or intends to revise or withdraw the ratings on AltaGas.

SHARE INFORMATION

At February 23, 2010 AltaGas had 82.8 million common shares outstanding and 8,000,000 Series A Preferred Shares outstanding with a combined market capitalization of $2.2 billion based on a closing trading price on February 23, 2011 of $23.88 per common share and $25.82 per Series A Preferred Share. At January 31, 2011 there were 4.8 million options outstanding and 1.7 million options exercisable under the terms of the share option plan.

DIVIDENDS AND DISTRIBUTIONS

Prior to corporate conversion, as of June 30, 2010, AltaGas declared distributions of $87.0 million for the first half of 2010. After the corporate conversion effective July 1, 2010, AltaGas declares and pays a monthly dividend to its shareholders.

AltaGas dividends are determined giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements. Subsequent to conversion to a corporation, as of December 31, 2010, AltaGas declared dividends of $54.1 million for the second half of 2010.

On October 27, 2010, the Board of Directors also declared a preferred dividend of $0.4589 per Series A Preferred Share for the period from August 11, 2010 to December 31, 2010, on AltaGas’ outstanding Series A Preferred Shares. The total preferred dividend (net of tax) declared in 2010 was $4.0 million.

The following table summarizes AltaGas’ dividends and distribution declaration history since 2008:

Dividends and Distributions

Years ended December 31 ($ per share)	2010	2009	2008
First quarter	0.54	0.54	0.525
Second quarter	0.54	0.54	0.525
Third quarter	0.33	0.54	0.535
Fourth quarter	0.33	0.54	0.540
Total	1.74	2.16	2.125

AltaGas was a trust for the first six months of 2010. As a result, distributions issued during that period were subject to income tax characterization similar to prior years. Assuming a unit was held throughout the first six months of 2010, for income tax purposes AltaGas expects 86.4 percent of the total distributions declared in this six month period to be taxed as income and 13.6 percent as return of capital. Investors that held AltaGas Income Trust units and received distributions during that period should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

NON-MONETARY TRANSACTIONS

In 2009, AltaGas entered into a non monetary transaction with a third-party in which it exchanged B.C. RECs for verified emission offsets that were generated in Alberta. The B.C. RECs were created through the generation of power at the Bear Mountain Wind Park in 2009 and 2010. The verified emission offsets received by AltaGas were used to offset the costs to comply with SGER for the 2008 compliance year. The contract was completed in the second quarter 2010.

CHANGES IN ACCOUNTING POLICIES

AltaGas changed the accounting policy for proprietary natural gas held in storage in third quarter 2010, from lower of cost and net realizable value to fair value. The results of the change in policy provide more relevant information on the effects of the transactions on AltaGas' net income as the changes in fair value on the future sales of the proprietary natural gas is recognized as risk management assets/liabilities and unrealized gains or losses on risk management. The accounting policy was applied retrospectively to January 1, 2010 with minimal impact to inventory and net income and therefore no prior period adjustments have been made.

Effective January 1, 2010, AUI, an indirect wholly-owned subsidiary of AltaGas, pursuant to an application filed with the regulator, prospectively changed its amortization policy. Under the new policy, additions to natural gas distribution assets are amortized in the year in which the assets are brought into active service. Net additions to natural gas distribution assets up to December 31, 2009 were not depreciated or amortized until the year after they were brought into active service. The change had an immaterial impact on net earnings for the year ended December 31, 2010.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

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

On September 10, 2010 AcSB amended the introduction to Part I of the CICA Handbook – Accounting to permit – but not to require – qualifying entities with rate regulated activities 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.

AltaGas is a qualified entity for the deferral period proposed by AcSB, based on the activities of AUI and Heritage Gas. While AltaGas' IFRS conversion project was on track to meet the original conversion deadline, AltaGas has elected to use the deferral offered by the AcSB given the uncertainty with respect to the application of IFRS to the rate regulated operations, which are pervasive and central to AltaGas' business model and a component of the Company's financial reports. AltaGas will reassess the accounting policy choices available and will determine those most appropriate for AltaGas' business activities, including the option to adopt US GAAP rather than IFRS. If AltaGas decides to adopt IFRS accounting standards, the transition date will be effective January 1, 2011 and the conversion date will be January 1, 2012.

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. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Financial instruments and hedge accounting

All financial instruments on the balance sheet are initially measured 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 of a financial instrument depends on its classification. AltaGas does not have any held to maturity financial instruments.

Held for trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, and changes to fair value are recorded in income. Loans and receivables are accounted for at their 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 accounted for at their fair value, and changes to fair value are recorded through other comprehensive income. 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 accounted for at their 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 total 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 expected purchase, sale or usage requirements exception, are carried on the Consolidated Balance Sheets at fair value. AltaGas used January 1, 2003 as the transition date for identifying embedded derivatives.

Fair value is defined as the amount of consideration that would be agreed upon in an arms length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in active market requires minimal judgment by management. Where bid or ask prices in an active market are not available, management's judgment on valuation inputs is necessary to determine fair value. 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. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by management.

AltaGas applies hedge accounting to its arrangements that qualify for hedge accounting treatment for cash flow hedges. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while any ineffective portion is recognized in income. Gains and losses on derivatives are reclassified to net income from accumulated other comprehensive income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

AltaGas designates certain derivatives as hedges at the inception of the hedging contract. The effectiveness of hedges is assessed on a regular basis and any changes in the fair value resulting from hedge ineffectiveness, is immediately recognized as income.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit of production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that AltaGas recognizes from period to period.

Asset retirement obligations and other environmental costs

AltaGas records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs are critical accounting estimates because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2045 and 2060), requiring AltaGas to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Asset impairment

AltaGas reviews long lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the AltaGas' Consolidated Financial Statements.

With respect to impairment assessment, management has made fair value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

Income taxes

The Company and, prior to July 1, 2010, the Trust, is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial future income tax assets and liabilities are recognized in the Consolidated Financial Statements of AltaGas. The recognition of future tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the future tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of tax authorities or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See note 13 to the Consolidated Financial Statements.

Pension plans and post-retirement benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. For post retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Notes 2 and 22 to the Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Rate regulation

AltaGas acquired AUI and Heritage Gas in the acquisition of Utility Group (note 3 of the 2010 Consolidated Financial Statements), which also owns one-third of Inuvik Gas. AUI, Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the AUC, NSUARB and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC and NSUARB 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 and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using 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 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 though 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.

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 with AltaGas.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of AltaGas is responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (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 to provide reasonable assurance that material information relating to AltaGas is made known to them and information required to be disclosed by AltaGas in its annual filings, interim filings and other documents filed or submitted under securities legislation are recorded, processed, summarized and reported within the time periods specified in securities legislation.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DC&P and, based on that evaluation, have concluded that AltaGas' DC&P were effective at December 31, 2010.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of AltaGas' employees, ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with Canadian GAAP.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' ICFR based on the framework established by the Committee of Sponsoring Organizations (COSO) and have concluded that AltaGas' ICFR was effective at December 31, 2010 based on that evaluation.

During 2010 there were no changes made to the AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, AltaGas' ICFR.

FOURTH QUARTER HIGHLIGHTS

Net income applicable to common shares for fourth quarter 2010 was $26.5 million ($0.32 per share) compared to $32.1 million ($0.40 per share) in the same period in 2009. Adjusting for the impact of mark-to-market accounting, net income applicable to common shares in fourth quarter 2010 was $31.4 million ($0.38 per share) compared to $38.3 million ($0.48 per share) for the same period last year. Adjusted for the impact of mark-to-market accounting, earnings reported by the operating segments, including the Corporate reporting segment were strong at $52.7 million in the quarter compared to $47.4 million in fourth quarter last year. Operating results were strong, driven by the addition of full quarter contribution from the Utility business, higher fees earned at some facilities and higher frac spreads which partially offset the impact of weaker realized power prices in Alberta and lower volumes at some processing facilities. The Gas, Power and Utility businesses reported operating income of $56.7 million in fourth quarter 2010 compared to $54.9 million in fourth quarter last year.

The Gas business reported higher operating income primarily due to higher extraction and transmission fees and realized frac spreads and lower amortization. The Power business reported lower earnings as a result of the continued weaker power markets in Alberta but benefited from higher earnings at the gas-fired peakers. The Utility business reported higher operating income primarily due to a full quarter of Heritage Gas and Utility Group compared to 2009. Corporate reporting segment reported a loss of $4.0 million in fourth quarter 2010 compared to a loss of $7.4 million in the same quarter last year, adjusted for mark-to-market accounting.

On a cash flow basis, funds from operations for the three months ended December 31, 2010 was $57.9 million ($0.70 per share) compared to $51.0 million ($0.64 per share) in the fourth quarter 2009. EBITDA adjusted for the impact of mark-to-market accounting in fourth quarter 2010 was $75.7 million ($0.92 per share) compared to $68.2 million ($0.85 per share) in the same period last year.

On a consolidated basis, net revenue for fourth quarter 2010 was $130.8 million compared to $115.4 million in same period 2009. The Gas reporting segment's net revenue was largely unchanged from the prior year as higher extraction and transmission revenues and gas marketing sales were offset by lower gas processing results and lower storage margins. Net revenue in the Power reporting segment was slightly higher due to larger contributions from gas-fired peakers and the Harmattan cogeneration, lower PPA costs offset by lower realized power prices in Alberta. The Utility business reported higher net revenue due to a full quarter contribution compared to a partial fourth quarter 2009 when AltaGas acquired the Utility business. The Corporate reporting segment recorded higher net revenue due to lower unrealized losses on risk management contracts, mark-to-market valuation of investments, offset partially by lower investment income.

Operating and administrative expense for fourth quarter 2010 was $60.1 million, up from $55.5 million in same quarter 2009. The increase was due to incremental costs associated with AltaGas' growth including the addition of the Utility business and higher operating costs at extraction facilities due to higher volumes. These increases were partially offset by lower operating costs related to the gas processing businesses due to lower volumes processed and cost control measures.

Amortization expense for fourth quarter 2010 was $22.4 million compared to $20.3 million in the same period 2009. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities, primarily the addition of the Utility business and Bear Mountain Wind Park, offset by lower amortization due to a change in estimates for the expected remaining useful lives of some assets within the Gas business. Accretion for asset retirement obligations for fourth quarter 2010 was $0.7 million compared to $0.8 million in the same period 2009. The decrease was due to the impact of revised estimates to some property, plant and equipment useful lives offset by growth in AltaGas' asset base from acquisition and construction activities.

Interest expense in fourth quarter 2010 was $12.1 million compared to $9.3 million for the same period 2009. The increase was due to a higher average borrowing rate offset by lower average debt balances of $0.9 billion as a result of the preferred share offering during third quarter 2010 (2009 – $1.0 billion). The average borrowing rate was 6.1 percent in fourth quarter 2010 compared to 4.9 percent in fourth quarter 2009.

In fourth quarter 2010, an income tax expense of $6.2 million was reported compared to a recovery of $2.9 million in fourth quarter 2009. The increase was due to higher income subject to tax as a result of conversion to a corporate structure. Income subject to tax in a trust structure was based on income for accounting purposes less the amount distributed to unitholders of the Trust. As a corporation, income tax expense is based on income for accounting purposes.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2011 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per share
Gathering and Processing volumes	5 Mmcf/d	0.009
Gathering and Processing operating margin per Mcf	1 cent /Mcf	0.021
Alberta electricity prices [1]	$1/MWh	0.017
Natural gas liquids fractionation spread [2]	$1 per Bbl	0.005
Interest rates	25 bps	0.007
Degree days [3]	5 percent	0.010

1 Based on approximately 40 percent of PPA volumes being hedged.

2 Based on approximately 70 percent of frac spread exposed NGL volumes being hedged.

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.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

($ millions)	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09	Q3-09	Q2-09	Q1-09
Total Revenue	**362.2**	297.4	334.0	360.5	336.4	291.4	285.8	354.6
Net revenue [1]	**130.8**	102.6	124.8	127.2	115.4	114.7	114.3	112.1
Operating income [1]	**47.7**	22.2	39.4	42.7	38.8	45.4	45.5	44.7
Net income applicable to common shares	**26.5**	6.0	28.4	36.4	32.1	34.7	36.9	37.5

($ per share)	Q4-10	Q3-10	Q2-10	Q1-10	Q4-09	Q3-09	Q2-09	Q1-09
Net income applicable to common shares								
Basic	**0.32**	0.07	0.35	0.45	0.40	0.44	0.47	0.50
Diluted	**0.32**	0.07	0.35	0.45	0.40	0.43	0.46	0.49
Distributions / dividends declared	**0.33**	0.33	0.54	0.54	0.54	0.54	0.54	0.54

1 Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of this MD&A.

Identifiable trends in AltaGas' business in the past eight quarters reflect the organization's internal growth, acquisitions, generally increasing power prices in Alberta until early 2009 and higher NGL frac spreads through most of 2010.

Significant items that impacted individual quarterly earnings were as follows:

- In latter part of fourth quarter 2008 and during the first half 2009, prices for power, natural gas and NGL declined, breaking the historical price trend for these products. Reduced natural gas prices have directly affected the activity of producers within the WCSB;
- In second quarter 2009, AltaGas purchased a short-term investment that resulted in an unrealized gain of $4.6 million;
- During 2009, AltaGas had adjusted liabilities related to natural gas transaction within energy services resulting in a one time revenue impact of $9.2 million;
- During fourth quarter 2009, Bear Mountain Wind Park was fully connected to the B.C. power grid and met the conditions for commercial operations in order to receive the firm price under the 25-year EPA with BC Hydro;
- During fourth quarter 2009, acquired all the outstanding common shares of Utility Group not previously held by AltaGas for $204.5 million including assumed debt;
- During fourth quarter 2009, acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas Limited for $111.0 million;
- During first quarter 2010, acquired all the outstanding common shares of Landis Energy Corporation for $25.6 million;
- On July 1, 2010, AltaGas converted from an income trust to a corporation resulting in AltaGas now being taxable;
- In third quarter 2010 AltaGas reported $21.1 million lower revenue as a result of mark-to-market accounting; and
- Completed the construction of a 15 MW gas-fired cogeneration facility at the Harmattan Complex that came into service during fourth quarter 2010.

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. The internal controls and systems of AltaGas Ltd. (AltaGas or the Company) are designed to provide reasonable assurance that AltaGas' assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by AltaGas to examine the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

David W Cornhill
Chairman and
Chief Executive Officer of
AltaGas Ltd.

February 23, 2011

Deborah S. Stein
Vice President Finance and
Chief Financial Officer of
AltaGas Ltd.

February 23, 2011

Independent Auditors' Report

To the Shareholders of AltaGas Ltd.

We have audited the accompanying consolidated financial statements of AltaGas Ltd., which comprise the consolidated balance sheets and shareholders' equity as at December 31, 2010 and 2009, and the consolidated statements of income, comprehensive income and accumulated other comprehensive (loss) income, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Ltd. as at December 31, 2010 and 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

ERNST & YOUNG, LLP
February 22, 2011

Calgary, Canada
Chartered Accountants

Consolidated Balance Sheets

As at December 31

($ thousands)	2010	2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,109	$ 3,584
Short-term investment (note 15)	–	19,436
Accounts receivable (note 15)	224,370	203,673
Inventory	13,107	1,401
Restricted cash holdings from customers	17,624	27,228
Regulatory assets (note 4)	2	2,567
Risk management (note 15)	41,226	66,271
Prepaid expense and other current assets	5,587	7,505
	304,025	331,665
Capital assets (note 5)	1,995,632	1,857,095
Energy arrangements, contracts and relationships (note 6)	120,848	128,949
Goodwill (note 7)	199,497	201,728
Regulatory assets (note 4)	76,515	60,885
Risk management (note 15)	22,587	18,132
Long-term investments and other assets (note 8)	32,588	30,487
	$ 2,751,692	$ 2,628,941
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 228,772	$ 158,319
Dividends payable	9,078	15,110
Short-term debt (note 9)	9,478	14,471
Current portion of long-term debt (note 10)	1,508	591,944
Customer deposits	21,432	30,678
Regulatory liabilities (note 4)	1,494	1,403
Risk management (note 15)	39,209	34,200
Other current liabilities	12,302	14,830
	323,273	860,955
Long-term debt (note 10)	893,498	408,170
Asset retirement obligations (note 12)	39,516	41,771
Future income taxes (note 13)	233,763	228,596
Regulatory liabilities (note 4)	18,518	16,610
Risk management (note 15)	20,598	14,491
Future employee obligations (note 21)	11,495	9,491
	1,540,661	1,580,084
Shareholders' equity (notes 16 and 17)	1,211,031	1,048,857
	$ 2,751,692	$ 2,628,941

Commitments and contingency (notes 9, 10, 15, 19, 21 and 25)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd:

DAVID W. CORNHILL
Director

ROBERT B. HODGINS
Director

Consolidated Statements of Income

For the years ended December 31 ($ thousands except per share amounts)	2010	2009
REVENUE		
Operating	$ 1,352,427	$ 1,249,649
Unrealized gain (loss) on risk management (note 15)	(1,337)	3,697
Other revenue (notes 11 and 15)	2,962	14,919
	1,354,052	1,268,265
EXPENSES		
Cost of sales	868,554	811,688
Operating and administrative	241,540	205,081
Accretion of asset retirement obligations (note 12)	2,880	3,138
Amortization:		
Capital assets	79,216	64,157
Energy arrangements, contracts and relationships	9,964	9,964
	1,202,154	1,094,028
Foreign exchange loss	67	1
Interest expense		
Short-term debt	1,533	1,283
Long-term debt	47,309	30,476
Income before income taxes	102,989	142,477
Income tax expense (recovery) (note 13)		
Current income tax	(222)	981
Future income tax	1,949	187
Net income	101,262	141,309
Preferred share dividends (net of tax)	(4,038)	–
Net income applicable to common shares	$ 97,224	$ 141,309
Net income per share (note 18)		
Basic	$ 1.19	$ 1.80
Diluted	$ 1.19	$ 1.79
Weighted average number of shares outstanding (thousands) (notes 17 and 18)		
Basic	81,512	78,540
Diluted	81,891	79,371

See accompanying notes to the Consolidated Financial Statements.

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

For the years ended December 31 ($ thousands)	2010	2009
Net income	**$ 101,262**	$ 141,309
Other comprehensive (loss) income, net of tax		
Unrealized net (loss) gain on available-for-sale financial assets	**(2,421)**	3,877
Unrealized net (loss) gain on derivatives designated as cash flow hedges	**(25,369)**	15,088
Reclassification to net income of net (loss) gain on derivatives designated as cash flow hedges pertaining to prior periods	**3,813**	(29,309)
	(23,977)	(10,344)
Comprehensive income	**$ 77,285**	$ 130,965
Accumulated other comprehensive income, beginning of year	**$ 21,225**	$ 31,569
Other comprehensive loss, net of tax	**(23,977)**	(10,344)
Accumulated other comprehensive (loss) income, end of year (note 15)	**$ (2,752)**	$ 21,255

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Shareholders' Equity

($ thousands)	2010	2009
Common shares		
Balance, beginning of year	$ 982,662	$ 850,992
Shares issued for cash on exercise of options	4,915	1,246
Shares issued under DRIP [1]	32,062	34,169
Shares issued on exercise of warrants	3,394	–
Shares issued on conversion of convertible debentures	–	71
Shares issued on public offering (net of $5.4 million of issuance costs and $0.9 million tax benefit [2]	–	96,184
Balance, end of year	1,023,033	982,662
Preferred shares		
Balance, beginning of year	–	–
Shares issued on public offering (net of issuance costs)	194,126	–
Balance, end of year	194,126	–
Contributed surplus		
Balance, beginning of year	5,621	4,261
Amortization of share options	546	376
Exercise of share options	(1,511)	(318)
Cancellation of share options	(90)	(213)
Other adjustments (Notes 11 and 17)	1,106	1,515
Balance, end of year	5,672	5,621
Warrants		
Balance, beginning of year	4,500	4,500
Exercised	(4,500)	–
Balance, end of year	–	4,500
Accumulated earnings		
Balance, beginning of year	34,849	64,547
Net income	101,262	141,309
Distributions	(86,982)	(170,831)
Common share dividends	(54,139)	–
Preferred share dividends (net of tax)	(4,038)	–
Transition adjustment resulting from adopting new financial instruments accounting standards	–	(176)
Balance, end of year	(9,048)	34,849
Accumulated other comprehensive (loss) income		
Balance, beginning of year	21,225	31,569
Other comprehensive loss	(23,977)	(10,344)
Balance, end of year	(2,752)	21,225
Total shareholders' equity	$ 1,211,031	$ 1,048,857

1 Distribution/dividend reinvestment program.

2 Net proceeds on issuance of shares will not tie to the shares issued due to non-cash items, including tax benefits.

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31 ($ thousands)	2010	2009
Cash from operations		
Net income	$ 101,262	$ 141,309
Items not involving cash:		
Amortization	89,180	74,121
Accretion of asset retirement obligations (note 12)	2,880	3,138
Share-based compensation	145	(195)
Future income tax expense (recovery) (note 13)	1,949	187
Gain on sale of investments and assets	(6,898)	(6,804)
Equity income	(328)	(158)
Unrealized losses (gains)	6,144	(9,468)
Goodwill impairment (note 7)	–	150
Other	1,628	2,788
Non-operating investment income	(923)	(2,809)
Asset retirement obligations settled (note 12)	(518)	(384)
Net change in non-cash working capital (note 20)	(1,939)	(17,729)
	192,582	184,146
Investing activities		
Increase (decrease) in customer deposits	9,604	(3,211)
Capital expenditures	(157,027)	(242,970)
Disposition of capital assets	334	–
Acquisition of energy services arrangements, contracts and relationships	(1,863)	–
Investment in regulatory assets	(10,335)	(6,014)
Distributions from equity investments	384	427
Disposition (acquisition) of short-term investments	21,204	(8,198)
Income from short-term investment	923	2,809
Business acquisition (note 3)	(22,720)	(191,277)
Acquisition of long-term investments and other assets	(5,240)	(15,658)
Disposition of long-term investments and other assets	2,871	–
	(161,865)	(464,092)
Financing activities		
Issuance (repayment) of short-term debt	(9,469)	9,978
Net issuance (repayment) of revolving long-term debt	(372,028)	16,132
Issuance of long-term debt	372,974	295,080
Repayment of long-term debt	(101,733)	(18,017)
Dividends and distributions	(151,843)	(168,666)
Net proceeds from issuance of common shares	35,781	130,719
Net proceeds from issuance of preferred shares	194,126	–
	(32,192)	265,226
Change in cash and cash equivalents	(1,475)	(14,720)
Cash and cash equivalents, beginning of year[1]	3,584	18,304
Cash and cash equivalents, end of year	$ 2,109	$ 3,584

1 Opening balance of cash and cash equivalents adjusted to reflect a prior period adjustment to a non-operated joint venture.

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. STRUCTURE OF ALTAGAS LTD.

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

BASIS OF PRESENTATION

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

CHANGES IN ACCOUNTING POLICIES

2010

AltaGas changed the accounting policy for proprietary natural gas held in storage in third quarter 2010, from lower of cost and net realizable value to fair value. The results of the change in policy provide more relevant information on the effects of the transactions on AltaGas' net income as the change in fair value on the future sales of the proprietary natural gas is recognized as risk management assets/liabilities and unrealized gains or losses on risk management. The accounting policy was applied retrospectively to January 1, 2010 with minimal impact to inventory and net income and therefore no prior period adjustments were made.

Effective January 1, 2010, AltaGas Utilities Inc. (AUI), an indirect wholly-owned subsidiary of AltaGas, pursuant to an application filed with the regulator, prospectively changed its amortization policy. Under the new policy, additions to natural gas distribution assets are amortized in the year in which the assets are brought into active service. Net additions to natural gas distribution assets up to December 31, 2009 were not depreciated or amortized until the year after they were brought into active service. The change had an immaterial impact on net earnings for the year ended December 31, 2010.

2009

Effective January 1, 2009 AltaGas adopted Emerging Issues Committee (EIC) 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" and the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 3064 "Goodwill and Intangible Assets". In accordance with the transitional provisions for these new standards, these policies were adopted retrospectively with minimal impact to goodwill, intangible assets and net income. Therefore no prior period adjustments were made.

Effective October 8, 2009 AltaGas adopted the changes to Section 1100 "Generally Accepted Accounting Principles" and Section 3465 "Income Taxes" related to the recognition and measurement of assets and liabilities arising from rate regulation. AltaGas adopted these standards as a result of the acquisition of AltaGas Utility Group Inc. (Utility Group) (note 3).

Effective December 31, 2009 AltaGas adopted the revisions to Section 3862 "Financial Instruments – Disclosures". This policy was adopted retrospectively.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

In January 2009, the EIC reached a consensus that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Accordingly, AltaGas was required to fair value derivative instruments, at the beginning of the period of adoption, to take into account both its own credit risk and counterparty credit risk. Any resulting difference has been recorded as an adjustment to retained earnings with the exception of cash flow hedges which have been recorded in accumulated other comprehensive income.

In accordance with CICA Handbook Section 3863 "Financial Instruments – Presentation", AltaGas changed its presentation of derivative financial assets and financial liabilities to report the net amount in the balance sheet where AltaGas has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The net effect on AltaGas' financial statements as at January 1, 2009 resulting from the above mentioned changes is as follows:

Balance Sheet Account Affected	Increase (Decrease)
Current assets – risk management	(25,772)
Long-term assets – risk management	(5,983)
Current liabilities – risk management	(25,421)
Long-term liabilities – risk management	(5,900)
Future income taxes	(285)
Shareholders' equity – accumulated earnings	(176)
Shareholders' equity – accumulated other comprehensive income	27

The unrealized gains and losses included in accumulated earnings and accumulated other comprehensive income were recorded net of income tax recovery of $287,645 and expense of $2,629, respectively.

Financial Instruments – Disclosures

Effective for annual financial statements for fiscal years ending after September 30, 2009, the CICA revised standards under Handbook Section 3862 "Financial Instruments – Disclosures". The revisions require additional disclosure based on a fair value hierarchy that reflects the significance of the inputs used in measuring fair value. Financial assets and financial liabilities with fair value measurement based on quoted prices (unadjusted) in active markets are included in Level 1, inputs other than quoted prices that are observable either directly or indirectly in Level 2 and inputs that are not based on observable market data in Level 3. The disclosure requirements are effective for AltaGas beginning December 31, 2009. The additional information to comply with these standards is disclosed in note 15.

Rate Regulated Assets and Liabilities

Effective October 8, 2009, the revisions to CICA Handbook Section 1100 "Generally Accepted Accounting Principles" pertain to the recognition and measurement of assets and liabilities arising from rate regulation become applicable to the Company. As a result of adopting these changes, Utility Group, an indirect wholly-owned subsidiary of AltaGas, reclassified $16.3 million of reserves for future removal and site restoration costs previously netted against capital assets to non current regulatory liabilities.

CHANGES IN ACCOUNTING ESTIMATES

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

The change in estimated useful lives was accounted for on a prospective basis from July 1, 2010. The change in estimate to the lives of AltaGas' facilities resulted in a decrease in amortization expense of $3.8 million and an increase in after tax earnings of $2.9 million in 2010. The change in estimate will affect amortization expense in future periods.

SIGNIFICANT ACCOUNTING POLICIES

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Regulation

AltaGas acquired AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas) in the acquisition of Utility Group (note 3), which also owns one-third of Inuvik Gas. AUI, Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC), the Nova Scotia Utility and Review Board (NSUARB) and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC and NSUARB 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 and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using 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 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.

See note 4 for a description of the financial statement effects of rate regulation.

Cash and Cash Equivalents

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

Short-term Investment

Short-term investments are highly liquid investments with no contractual maturities. Short-term investments are recorded at fair value based on quoted market prices, with changes in fair value recorded in other revenue.

Inventory

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

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

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 sheets. 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.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Major renewals or betterments are included in the cost-of-capital assets while routine repair and maintenance costs are expensed in the period incurred.

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

Gas	
Extraction and transmission (E&T) assets	15–40 years
Field gathering and processing (FG&P) assets	15–36 years
Energy services assets	19 years
Storage assets	20–50 years
Other assets	1–32 years
Power	
Assets under capital lease	10-years
Power generation assets	20–30 years
Utility	1.44–42.36 percent
Corporate	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. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term debt.

As required by the respective regulatory authorities, net additions to natural gas distribution assets at Heritage Gas are not depreciated until the year after they are brought into active service and net additions to natural gas distribution 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.

Energy Arrangements, Contracts, Relationships and Amortization

Energy arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Energy services relationships	15 years
E&T contracts	10–20-years

AltaGas owns 50 percent of two Sundance B 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 recorded on a proportionate basis. 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 terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded based on target generator availability.

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 Energistics Group Inc., and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts 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 recorded at fair value and amortized on a straight-line basis over the average expected life of the contracts.

Financial Instruments

All financial instruments, including derivatives, are included on the Consolidated Balance Sheets 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 are entered into with the intention of generating a profit and consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, and changes to fair value are recorded in income. Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. AltaGas does not have any held-to-maturity financial instruments. Loans and receivables are accounted for at their 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 accounted for at their 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 accounted for at their 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 total 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 expected purchase, sale or usage requirements exception, are carried on the Consolidated Balance Sheets at fair value. AltaGas used January 1, 2003 as the transition date for identifying embedded derivatives.

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. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

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.

Comprehensive Income and Equity

AltaGas' financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income, which consists of earnings and the effective portion of changes in unrealized gains and losses related to available for sale assets and cash flow hedges. In addition, AltaGas presents separately in its shareholders' equity note the changes for each of its components of shareholders' equity.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available for sale or held for trading. Available-for-sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI. Investments in equity instruments that do not have a quoted market price in an active market will be measured at cost. Held-for-trading assets are initially accounted for at fair value with changes in fair value recorded in other revenue.

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.

Revenue Recognition

In the Gas business, the extraction and transmission, field gathering and processing and energy services businesses recognize 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 regulating authority.

The Power reporting segment recognizes revenue based on target generator availability in accordance with the Sundance B PPAs and at the time the product or service is delivered for all other power generation.

Realized gains and losses from risk management activities related to commodity prices are recognized in the related reporting segment revenues when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheets. 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.

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.

Recognition Date

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

Effective Interest Method

AltaGas uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. 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.

Share-Based Compensation Plans

On July 1, 2010 AltaGas completed the conversion from an income trust to a corporation. 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 an equity-based compensation plan in which participants receive phantom shares requiring settlement of 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

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 14.7 years and 13.1 years respectively. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

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. The Specified Investment Flow through ("SIFT") tax, which received royal assent on June 22, 2007, created a new tax that would be applied to distributions from certain income trusts and partnerships, including the Trust, effective January 1, 2011. Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust recorded a SIFT future income tax expense and future income tax liability for the years ended December 31, 2007, 2008 and 2009. This non-cash expense had no immediate impact on cash flows. 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 2011.

Income taxes were calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the substantively 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.

On July 1, 2010 AltaGas completed the conversion from an income trust to a corporation pursuant to a plan of arrangement under the Canadian Business Corporations Act. After July 1, 2010 income taxes for the Company and its subsidiaries are calculated using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the substantively 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 future income taxes expected to be included in future rates and recovered from or paid to customers in the future.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non routine transactions have been recorded at the exchange amount.

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. Diluted net income is increased by the interest on the convertible debentures and decreased by the accretion on the convertible debentures. As of September 16, 2009 AltaGas redeemed all outstanding convertible debentures (note 11).

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with 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.

Warrants

Warrants are recorded at fair value, deemed to be the gross proceeds upon issue, and are included as part of shareholders' equity.

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.

FUTURE ACCOUNTING CHANGES

Section 1582 "Business Combinations"

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. The new CICA Handbook Section 1582 will replace Section 1581 "Business Combinations" establishing standards for the accounting for a business combination that will more closely resemble those under International Financial Reporting Standards (IFRS). Earlier adoption of this section is permitted, however AltaGas has elected not to early adopt. The section is not expected to have a material impact on the Consolidated Financial Statements.

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

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbook Sections 1601 and 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Earlier adoption of this section is permitted, however AltaGas has elected not to early adopt. Management has not fully determined the impact of adopting this standard.

International Financial Reporting Standards (IFRS)

Canadian publicly-traded companies were required to prepare their financial statements in accordance with IFRS as issued by the International Accounting Standards Board, for financial years beginning on or after January 1, 2011.

On July 28, 2010 the Accounting Standards Board (AcSB) issued an exposure draft proposing that qualifying entities with Rate Regulated Activities (RRA) will be permitted, but not required, to continue applying the accounting standards in Part V of the Handbook for an additional two years.

On September 10, 2010 the AcSB amended the proposal to require qualifying entities 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. AltaGas currently follows Part V of the Handbook.

AltaGas is a qualified entity for the deferral period as issued by AcSB, based on the activities of its Utility business and has elected to defer its implementation of IFRS. AltaGas will reassess the accounting policy choices available and will determine those most appropriate for AltaGas' business activity, including the option to adopt US GAAP rather than IFRS.

3. BUSINESS ACQUISITIONS

2010

Landis Energy Corporation (Landis)

On March 22, 2010 AltaGas acquired all of the outstanding common shares of Landis Energy Corporation. Landis is a developer of underground natural gas storage facilities, focused on opportunities in Atlantic Canada.

AltaGas paid Landis shareholders $0.80 per common share in cash with an aggregate purchase price of $25.6 million, including $3.5 million in estimated transaction costs. The acquisition was accounted for as an asset acquisition.

2009

AltaGas Utility Group Inc.

On October 8, 2009 AltaGas Holdings No.3 Inc. (AltaGas Holdings #3), an indirect wholly-owned subsidiary of AltaGas acquired all of the outstanding common shares of AltaGas Utility Group Inc. (Utility Group) not already owned by AltaGas and its affiliates.

Utility Group was a publicly-traded company holding interests in AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas) and Inuvik Gas Ltd. (Inuvik Gas). Utility Group also holds a 33.3335 percent interest in the Ikhil Joint Venture (Ikhil) which produces and supplies natural gas in Inuvik, Northwest Territories.

AltaGas paid Utility Group shareholders $10.50 per common share in cash. The aggregate purchase price was $77.6 million, including $75.2 million of cash for the remaining 81.7 percent of Utility Group and $2.4 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Utility Group using the equity method. As a result, the Company's portion of income earned by Utility Group was recorded as other revenue in the Corporate reporting segment.

As of October 8, 2009, the operating results of Utility Group are consolidated with the results of the Company within the Utility reporting segment.

Heritage Gas Limited

On November 18, 2009 AltaGas acquired all of the Heritage Gas common shares and shareholder loans not already owned. Heritage Gas operates a full regulation class natural gas distribution franchise in Nova Scotia. AltaGas paid approximately $109.8 million for the remaining 75.1 percent in Heritage Gas. The aggregate purchase price was $110.7 million, including $109.8 million of cash for all of the common shares and shareholder loans not previously owned and $0.9 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Heritage Gas using the proportional accounting method.

Purchase Price Allocation

The following table summarizes the total consideration and the final estimated fair value of the assets acquired and liabilities assumed on October 8, 2009 and November 18, 2009 for Utility Group and Heritage Gas respectively.

	Utility Group	Heritage Gas	Total
Cash consideration	$ 75,199	$ 109,828	$ 185,027
Transaction costs	2,430	895	3,325
Total consideration	$ 77,629	$ 110,723	$ 188,352
Purchase price allocation			
Assets acquired			
Current assets	$ 16,743	$ 5,376	
Capital assets	149,371	74,808	
Regulatory assets	16,633	34,509	
Goodwill (note 7)	42,180	13,591	
Long-term investments and other assets	3,267	–	
Subtotal – assets acquired	228,194	128,284	356,478
Less liabilities assumed			
Current liabilities	23,685	5,037	
Long-term debt	101,511	3,177	
Regulatory liabilities	13,587	–	
Asset retirement obligations	96	–	
Future income taxes	9,113	9,347	
Future employee obligations	2,573	–	
Subtotal – liabilities assumed	150,565	17,561	168,126
	$ 77,629	$ 110,723	$ 188,352

In accordance with CICA Handbook Section 1600 "Consolidated Financial Statements" AltaGas accounted for the Utility Group acquisition as a step by step purchase resulting from the Company's original equity accounted investment in Utility Group. Accordingly, the $12.3 million investment was proportionately allocated to identifiable assets and liabilities of Utility Group.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

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

Regulatory assets and liabilities recognized in the Consolidated Balance Sheet are as follows:

Years ended December 31		2010		2009
Regulatory assets – current				
Deferred cost of gas	$	2	$	2,567
		2		2,567
Regulatory assets – non-current				
Deferred regulatory costs		265		474
Future recovery of other retirement benefits		1,631		1,416
Deferred depreciation		5,479		2,546
Deferred future taxes		28,798		22,583
Revenue deficiency account		40,342		33,866
	$	76,515	$	60,885
Regulatory liabilities – current				
Deferred property taxes		51		70
Deferred cost of gas		825		72
Deferred regulatory costs		618		1,261
	$	1,494	$	1,403
Regulatory liabilities – non-current				
Future removal and site restoration costs		18,518		16,610
	$	18,518	$	16,610

Return on Rate Base

A generic cost-of-capital proceeding in Alberta in 2009 resulted in an AUC decision setting the return on equity for 2009 and 2010 at 9.00 percent. The AUC further set AUI's regulated capital structure at 57 percent debt and 43 percent equity for 2009 and 2010.

Heritage Gas' regulated capital structure is 55 percent debt and 45 percent equity with a return on equity of 13 percent. The NSUARB has approved this structure and return until December 31, 2011.

Additional Items Affected by Rate Regulation

Heritage Gas has approval from the NSUARB to use a Revenue Deficiency Account (RDA). The RDA changes based on the difference between the actual revenue billed and the revenue required to earn the rates of return approved by the NSUARB. In Heritage Gas' customer development stage, it is expected that the actual revenue billed will be less than the revenue required to earn the approved rates of return and therefore an RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rates of return, and the RDA will be drawn down. In 2010, the NSUARB ruled that the RDA cannot exceed $50 million unless approved by the NSUARB. Heritage Gas may, if necessary, apply to the NSUARB for increases to the RDA limit. The RDA at December 31, 2010 was $40.3 million (December 31, 2009 – $33.9 million). The effect of the RDA accumulation was to increase 2010 revenue by $6.5 million (2009 – $2.0 million). In the absence of regulatory accounting, GAAP would require that the revenue deficiency account would not be recognized and would reduce operating income by $6.5 million in 2010 (2009 – $2.0 million).

Pursuant to the NSUARB decision dated February 12, 2009 Heritage Gas was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the 2009 – 2011 period. Heritage Gas is recording amortization under GAAP, and has recorded a regulatory asset of $5.5 million, equal to the amortization recorded under GAAP. For the year ended December 31, 2010 the corresponding regulatory revenue accrual was $5.5 million. The amortization deferred for regulatory purposes is expected to be recovered from customers in the future once the NSUARB allows amortization for regulatory purposes to resume. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred. In this case, operating results for 2010 would have been $2.9 million lower (2009 – $2.5 million lower).

Natural gas and transportation costs are included in the approved tariff on a monthly forecast basis. For rate setting purposes, differences between forecast and actual costs in the month are held for collection or refund in the following months. AltaGas recognizes the cost variances as a regulatory asset or liability, based on the expectation that amounts held from one month to the next for regulatory purposes will be approved for collection from, or refund to, customers in future months. AltaGas expects to recover the outstanding deferred cost in the first quarter of the following year. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred. In this case, operating results for 2010 would have been $3.4 million higher (2009 – $2.3 million lower).

Future income taxes expected to be included in future recoveries from customers are deferred in accordance with CICA Handbook Section 3465. In the absence of rate regulation, GAAP would require that future income taxes be recognized in income when incurred and net income would have been $6.2 million lower in 2010 (2009 – $4.4 million lower).

Future removal and site restoration costs are included in revenue as allowed by the AUC. AUI recognizes the variance between amounts included in revenue and removal and site restoration costs incurred as a regulatory asset or liability, based on the expectation that amounts held for regulatory purposes will be approved for collection from, or refund to, customers in future periods. In the absence of regulatory accounting, GAAP would require that the variance between the amounts collected and incurred be recognized as revenue and expenses in the period collected and incurred. In this case, operating income for 2010 would have been $1.9 million higher (2009 – $0.3 million higher).

5. CAPITAL ASSETS

			2010			2009
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Gas						
E&T	**$ 902,037**	**$ (125,384)**	**$ 776,653**	$ 896,753	$ (97,998)	$ 798,755
FG&P	**692,928**	**(229,048)**	**463,880**	629,284	(202,791)	426,493
Energy services	**1,425**	**(1,319)**	**106**	1,555	(1,343)	212
Storage	**60,528**	**(859)**	**59,669**	23,423	(284)	23,139
Other	**11,798**	**(8,357)**	**3,441**	8,303	(5,339)	2,964
Power						
Power generation	**370,217**	**(9,013)**	**361,204**	323,448	(1,081)	322,367
Capital lease (note 10)	**13,798**	**(8,760)**	**5,038**	13,798	(7,358)	6,440
Utility	**319,723**	**(11,352)**	**308,371**	271,464	(1,420)	270,044
Corporate	**34,354**	**(17,084)**	**17,270**	23,270	(16,589)	6,681
	$ 2,406,808	**$ (411,176)**	**$ 1,995,632**	$ 2,191,298	$ (334,203)	$ 1,857,095

Interest capitalized on capital construction projects for the year ended December 31, 2010 was $4.4 million (2009 – $7.1 million). At December 31, 2010 AltaGas had spent approximately $231.6 million (2009 – $326.8 million) on capital projects under construction that were not yet subject to amortization.

At Heritage Gas, net additions to natural gas distribution assets are not depreciated until the year after they are brought into use as consistent with regulatory practice. Effective January 1, 2010 net additions to natural gas distribution assets at AUI are depreciated commencing in the year in which the asset is brought into active service. Utility business assets not subject to amortization were $30.1 million as at December 31, 2010 (December 31, 2009 – $26.8 million).

6. ENERGY ARRANGEMENTS, CONTRACTS AND RELATIONSHIPS

	2010			2009		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services and E&T arrangements and contracts	$ 170,034	$ (63,370)	$ 106,664	$ 168,171	$ (54,799)	$ 113,372
Energy services relationships	20,892	(6,708)	14,184	20,892	(5,315)	15,577
	$ 190,926	$ (70,078)	$ 120,848	$ 189,063	$ (60,114)	$ 128,949

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding marketing contracts.

7. GOODWILL

	2010	2009
Balance, beginning of year	$ 201,728	$ 143,840
Acquisition (note 3)	–	58,038
Purchase price allocation adjustment	(2,231)	–
Goodwill impairment	–	(150)
Balance, end of year	$ 199,497	$ 201,728

Through its annual goodwill impairment testing in 2010, AltaGas determined that the fair value of investments was higher than the carrying amounts, therefore no impairment is recognized. In 2009, an investment was less than the book value and reduced the carrying value by $0.2 million.

8. LONG-TERM INVESTMENTS AND OTHER ASSETS

	2010	2009
Investments in publicly-traded entities	$ 24,447	$ 24,332
Equity accounted investments in private entities [1]	3,933	3,999
Accrued pension asset	1,703	1,361
Other	2,505	795
	$ 32,588	$ 30,487

1 AltaGas accounts for its investment in Boston Bar Limited Partnership, which has run-of-river hydroelectric operations, using the equity method.

9. SHORT-TERM DEBT

	2010	2009
Bank indebtedness	$ 4,528	$ 4,795
$50 million demand operating facility	4,320	–
$20 million demand operating facility	630	2,444
$15 million demand operating facility [1]	–	6,960
$1.0 million demand operating facility	–	272
	$ 9,478	$ 14,471

1 This demand operating facility was canceled on November 17, 2010.

Bank Indebtedness

Bank indebtedness bears interest at the lender's prime rate or at the interest rate applicable to bankers' acceptances. The prime lending rate at December 31, 2010 was 3.00 percent (December 31, 2009 – 2.25 percent).

Revolving Operating Credit Facilities

At December 31, 2010 AltaGas Ltd. held a $50 million (December 31, 2009 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. Letters of credit outstanding at December 31, 2010 were $0.02 million (December 31, 2009 – $2.7 million).

At December 31, 2010 the Utility Group held a $20 million (December 31, 2009 – $20 million) unsecured uncommitted demand operating credit facility with a Canadian chartered bank. Draws on the facility can be by way of prime rate loans, U.S. base rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding at December 31, 2010 were $2.9 million (December 31, 2009 – $1.0 million).

At December 31, 2010 AltaGas held a $1.0 million (December 31, 2009 – $1.0 million) demand credit facility with a Canadian chartered bank. The operating credit facility was acquired through the acquisition of Heritage Gas (note 3). It is secured by a general security agreement on the property of Heritage Gas and bears interest at prime plus one percent. Draws on the facility are by way of loans bearing interest at the bank's prime rate or by way of letters of credit or letters of guarantee for a fee.

10. LONG-TERM DEBT

	2010	2009
Credit facilities	$ 113,789	$ 490,518
Medium-term notes	775,000	500,000
Loan from Province of Nova Scotia	4,535	4,272
Capital lease obligations	6,076	7,484
Other long-term debt	807	1,049
Unamortized deferred financing costs	(5,201)	(3,209)
	895,006	1,000,114
Less current portion	1,508	591,944
	$ 893,498	$ 408,170

Credit Facilities

At December 31, 2010 AltaGas held a $600.0 million unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. This credit facility was used to retire and replace the previously held $150 million and $375 million credit facilities which matured in August and September 30, 2010, respectively. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. The credit facility matures on June 30, 2013.

On November 17, 2010, AltaGas restated and amended the Utility Group's maturing $130 million unsecured extendible revolving credit facility. The Utility Group unsecured extendible revolving credit facility with a syndicate of five banks was increased to $200 million and its term was extended by three years to mature on November 17, 2013. Borrowings on the facility can be by way of prime rate loans, U.S. base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans.

At December 31, 2010 AltaGas had drawn a principal of $114.5 million (December 31, 2009 – $490.5 million) against the facilities. The average rate on the AltaGas bankers' acceptances at December 31, 2010 was 3.01 percent (December 31, 2009 – 1.2 percent).

Medium-Term Notes

On January 19, 2007 AltaGas issued $100.0 million of 5.07 percent senior unsecured MTNs. The notes mature on January 19, 2012.

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

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

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

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

Loan from Province of Nova Scotia

On October 8, 2009 AltaGas acquired a loan from the Province of Nova Scotia through the acquisitions of Utility Group and Heritage Gas (note 3). The loan is non interest bearing until certain revenue targets are achieved, at which time interest will be charged prospectively at 6 percent. On or before July 31, 2011, AltaGas must elect to repay the loan in full on July 1, 2014 or in five equal installments beginning July 31, 2012. AltaGas may also elect to fully repay the loan at any time with no penalty. The loan is recorded at its amortized cost of $4.5 million. Interest expense is recorded at the effective interest rate of 6 percent. The face value of the loan as at December 31, 2010 is $5.6 million (2009 – $5.6 million).

Capital Lease Obligation

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 has payment commitments as follows, excluding the extended term option:

2011	$ 1,878
2012	1,878
2013	1,878
2014	1,254
	6,888
Less imputed interest at 6.85%	812
Present value of minimum lease payments	6,076
Less current portion	1,508
	$ 4,568

Interest expense on capital leases was $0.5 million in 2010 (2009 – $0.6 million).

Letter of Credit Facility

At December 31, 2010 AltaGas held a $75.0 million (December 31, 2009 – $75.0 million) unsecured three year extendible revolving term letter of credit facility with two Canadian chartered banks maturing on June 30, 2013. 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 that vary from 1.33 percent to 2.00 percent depending on the nature of the draw made. At December 31, 2010 AltaGas had letters of credit of $50.5 million (December 31, 2009 – $46.7 million) outstanding against the extendible revolving term letter of credit facility.

11. CONVERTIBLE DEBENTURES

On September 16, 2009 AltaGas redeemed $16.6 million of outstanding convertible debentures at an amount of $1,000.96 for each $1,000.00 principal amount. The redemption amount is equal to the principal plus all accrued and unpaid interest thereon.

AltaGas recognized a gain on redemption of convertible debentures of $0.1 million as other revenue and applied $1.6 million to contributed surplus related to the equity portion of the convertible debentures.

12. ASSET RETIREMENT OBLIGATIONS

	2010	2009
Balance, beginning of year	**$ 41,771**	$ 41,708
Obligations assumed under acquisition (note 3)	**–**	96
New obligations	**3,075**	742
Obligations settled	**(518)**	(384)
Revision in estimated cash flow	**(7,692)**	(3,529)
Accretion expense	**2,880**	3,138
Balance, end of year	**$ 39,516**	$ 41,771

AltaGas estimates the total future liability to settle the asset retirement obligations at December 31, 2010 was $347.7 million (December 31, 2009 – $278.2 million), excluding salvage values. The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 5.6 and 8.5 percent and are expected to be incurred between 2018 and 2075. No assets have been legally restricted for settlement of the estimated liability.

13. INCOME TAXES

Prior to July 1, 2010 amounts received by AltaGas in the form of interest, distributions or other income from its subsidiaries are taxable income to AltaGas. AltaGas is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributed all of its income to unitholders, AltaGas is not expected to be liable for income taxes while it operated as a trust.

After July 1, 2010 and the completion of the conversion from an income trust to a corporation, AltaGas commenced recording income taxes as a corporation only.

In 2010 $7.0 million of future income tax liabilities was assumed on the acquisition of Landis. In 2009, $18.5 million of future income tax liabilities was assumed as a result of the Utility Group and Heritage Gas acquisitions (note 3).

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before taxes as follows:

Years ended December 31	2010	2009
Income before taxes – consolidated	$ 102,989	$ 142,477
Financial instruments – net	1,337	(3,697)
Income before financial instruments and taxes	104,326	138,780
Income from AltaGas Income Trust distributed to unitholders	(76,146)	(135,119)
Income before income taxes – operating subsidiaries	28,180	3,661
Statutory income tax rate (%)	28.00	29.00
Expected taxes at statutory rates	7,890	1,062
Add (deduct) the tax effect of:		
Financial instruments	(632)	187
Rate reductions applied to future income tax liabilities	305	262
Permanent differences between accounting and tax basis of assets and liabilities	352	988
Non-taxable portion of capital gains on disposition of assets and investments	(277)	(1,798)
Other	225	(436)
Future income tax on regulated assets	(5,255)	(588)
Prior year adjustment	(881)	1,491
Income tax provision (recovery)		
Current	(222)	981
Future	1,949	187
	$ 1,727	$ 1,168
Effective income tax rate (%)	1.68	0.82

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 AltaGas' balance sheets at substantively enacted tax rates.

Future income taxes were composed of the following:

December 31	2010	2009
Capital assets	$ 222,202	$ 206,742
Regulatory assets	17,665	18,196
Deferred debt charges	(1,134)	(7)
Share issue costs	–	(40)
Partnerships	12,994	10,494
Deferred compensation	(3,632)	(4,942)
Financial instruments	1,192	10,711
Non-capital losses	(15,249)	(12,971)
Other	(275)	413
	$ 233,763	$ 228,596

14. CAPITAL DISCLOSURE

AltaGas' objective for managing capital is to maintain its investment grade credit ratings and allow the Company to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas considers shareholders' equity (including accumulated other comprehensive income), short-term and long-term debt (including current portion) less cash and cash equivalents to be part of its capital structure. AltaGas' overall strategy remains unchanged from 2009.

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 operating businesses. AltaGas' target debt-to-total capitalization ratio was 40 to 45 percent until third quarter 2009. Subsequent to the acquisition of Utility Group (note 3), AltaGas increased its target debt-to-total capitalization ratio to 45 to 50 percent. The increase is the result of the addition of regulated assets to AltaGas' portfolio of energy infrastructure assets. AltaGas' debt-to-total capitalization ratio as at December 31, 2010 was 42.8 percent (December 31, 2009 – 49.2 percent).

	2010	2009
Debt		
Short-term debt	$ 9,478	$ 14,471
Current portion of long-term debt	1,508	591,944
Long- term debt	893,498	408,170
	904,484	1,014,585
Shareholders' equity	1,211,031	1,048,857
Total capitalization	$ 2,115,515	$ 2,063,442
Debt-to-total capitalization ratio (%)	42.8	49.2

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 AltaGas' debt covenants for all credit facilities as at December 31, 2010:

Ratios [1]	Debt covenant requirements
Debt-to-total capitalization	not greater than 60 percent
EBITDA-to-interest expense	not less than 2.5x
Debt-to-total capitalization (Utility Group)	not greater than 67.5 percent

1 Debt covenant ratios are calculated in accordance with the credit facility agreements including adjustments for business acquisitions and will differ from management's internal calculation due to the definition of certain items in the credit facility agreements.

15. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations AltaGas purchases and sells natural gas, natural gas liquids (NGLs) and power commodities and issues short and long-term debt. AltaGas uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Company does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instruments

At December 31, 2010 and 2009, all derivatives, other than those that meet the expected purchase, sale or usage requirements exemption, were carried on the Consolidated Balance Sheets at fair value. The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate and foreign exchange derivatives used 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 of AltaGas' financial assets and liabilities were as follows:

Summary of Fair Values December 31, 2010	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]	$ 2,109	$ –	$ –	$ –	$ –	$ –	$ 2,109
Accounts receivable [1]	–	–	215,522	–	–	8,848	224,370
Restricted cash holdings from customers [1]	–	–	17,624	–	–	–	17,624
Risk management assets (current)	41,219	7	–	–	–	–	41,226
Prepaid expense and other current assets [1]	–	–	2,601	–	–	2,986	5,587
Risk management assets (non-current)	22,587	–	–	–	–	–	22,587
Long-term investments and other assets (note 8)	12,687	–	–	15,704	–	4,197	32,588
	$ 78,602	$ 7	$ 235,747	$ 15,704	$ –	$ 16,031	$ 346,091
Financial liabilities							
Accounts payable and accrued liabilities [1]	$ –	$ –	$ –	$ –	$ 64,031	$ 164,741	$ 228,772
Dividends payable	–	–	–	–	9,078	–	9,078
Short-term debt [1]	–	–		–	9,478	–	9,478
Current portion of long term debt [2]	–	–	–	–	1,508	–	1,508
Customer deposits [1]	–	–	–	–	21,432	–	21,432
Risk management liabilities (current)	36,697	2,512	–	–	–	–	39,209
Other current liabilities [1]	–	–	–	–	11,542	760	12,302
Long-term debt [3]	–	–	–	–	898,699	(5,201)	893,498
Risk management liabilities (non-current)	20,492	106	–	–	–	–	20,598
	$ 57,189	$ 2,618	$ –	$ –	$ 1,015,768	$ 160,300	$ 1,235,875

1 Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.
2 Fair value of current portion of long-term debt is approximately $1.5 million.
3 Fair value of long-term debt excluding non financial instruments is approximately $850.2 million.

Summary of Fair Values December 31, 2009	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]	$ 3,584	$ –	$ –	$ –	$ –	$ –	$ 3,584
Short-term investment [1]	19,436	–	–	–	–	–	19,436
Accounts receivable [1]	–	–	189,458	–	–	14,215	203,673
Restricted cash holdings from customers [1]	–	–	27,228	–	–	–	27,228
Risk management assets (current)	36,108	30,163	–	–	–	–	66,271
Prepaid expense and other assets [1]	–	–	1,064	–	–	6,441	7,505
Risk management assets (non–current)	16,673	1,459	–	–	–	–	18,132
Long–term investments and other assets (note 8)	11,327	–	–	13,327	–	5,833	30,487
	$ 87,128	$ 31,622	$ 217,750	$ 13,327	$ –	$ 26,489	$ 376,316
Financial liabilities							
Accounts payable and accrued liabilities [1]	$ –	$ –	$ –	$ –	$ 45,190	$ 113,129	$ 158,317
Dividends payable	–	–	–	–	15,110	–	15,110
Short-term debt [1]	–	–	–	–	14,471	–	14,471
Current portion of long-term debt [1]	–	–	–	–	591,944	–	591,944
Customer deposits [1]	–	–	–	–	30,678	–	30,678
Risk management liabilities (current)	31,408	2,792	–	–	–	–	34,200
Other current liabilities [1]	–	–	–	–	14,162	668	14,830
Long-term debt [3]	–	–	–	–	411,380	(3,210)	408,170
Risk management liabilities (non-current)	13,732	759	–	–	–	–	14,491
	$ 45,140	$ 3,551	$ –	$ –	$1,122,935	$ 110,587	$1,282,213

1 Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.
2 Fair value of current portion of long-term debt is approximately $591.8 million.
3 Fair value of long-term debt excluding non financial instruments is approximately $425.7 million.

Summary of Unrealized Gain (Loss) on Risk Management December 31	2010	2009
Natural gas	$ 4,534	$ 4,772
Storage optimization	1,288	–
NGL Frac Spread	(9,250)	281
Power	2,150	68
Heat rate	(482)	122
Interest rate swaps	481	4,523
Foreign exchange	(58)	(6,069)
	$ (1,337)	$ 3,697

Summary of Unrealized Gain (Loss) and Tax Expense (Recovery) on Derivatives Designated as Cash Flow Hedges

December 31	Unrealized gain (loss)	Tax expense (recovery)	2010	Unrealized gain (loss)	Tax expense (recovery)	2009
NGL Frac Spread	$ (764)	$ (432)	$ (1,196)	$ (2,555)	$ 714	$ (1,841)
Power	(969)	258	(711)	30,627	(8,557)	22,070
Bond forward	(2,300)	–	(2,300)	(2,881)	–	(2,881)
Available-for-sale	1,681	(226)	1,455	4,457	(580)	3,877
	$ (2,352)	$ (400)	$ (2,752)	$ 29,648	$ (8,423)	$ 21,225

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 value is based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly held 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 assets and liabilities. AltaGas uses over the counter derivative instruments to manage fluctuations in commodity, interest and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the assets or liabilities, 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 verified with or validated with public sources.

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

December 31, 2010	Level 1	Level 2	Level 3	Total
Financial assets				
Held-for-trading [1]	$ 12,687	$ 63,806	$ –	$ 76,493
Cash flow hedges	–	7	–	7
Available for sale	15,704	–	–	15,704
Financial liabilities				
Held-for-trading	–	57,189	–	57,189
Cash flow hedges	–	2,618	–	2,618

December 31, 2009	Level 1	Level 2	Level 3	Total
Financial assets				
Held-for-trading [1]	$ 30,763	$ 52,781	$ –	$ 83,544
Cash flow hedges	–	31,622	–	31,622
Available for sale	13,327	–	–	13,327
Financial liabilities				
Held-for-trading	–	45,140	–	45,140
Cash flow hedges	–	3,551	–	3,551

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 Magma Energy Corp. (Magma) through a private equity offering for $10 million. These shares were classified as available for sale. The changes in value for these common shares are reported within OCI, which was an unrealized loss of $2.4 million as at December 31, 2010 (2009 – unrealized gain of $3.9 million, net of tax), net of tax. In July 2009, AltaGas purchased additional common shares of Magma as part of its initial public offering. These shares were classified as held for trading. In July 2010, AltaGas purchased another tranche of common shares in Magma, which were also classified as held for trading. All shares of Magma are reported in long-term investments and other assets. As at December 31, 2010, AltaGas recognized an unrealized gain of $0.1 million in the Corporate reporting segment as other revenue (2009 – $1.3 million).

In October 2009 AltaGas acquired an equity investment in a public company with the acquisition of Utility Group (note 3). The shares were classified as available for sale. The changes in value for these common shares were reported within OCI. In 2010 the equity investment was sold and a gain of $0.6 million was reported in other revenue.

Short-Term Investment

AltaGas disposed short-term investments during 2010 and realized a gain of $6.9 million (2009 – $6.8 million). Upon selling the short-term investments, AltaGas recognized an unrealized loss of $4.5 million, which reversed the unrealized gain from 2009. Unrealized gains and losses on short-term investments were recorded in the Corporate reporting segment as other revenue.

Market Risk on Financial Instruments

AltaGas is exposed to market risk and potential loss from changes in the values of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Commodity Price Risk Management

Natural Gas

AltaGas purchases and sells natural gas to its customers. The fixed price and market price contracts for both the purchase and sale of natural gas extend to 2015. Additionally, AltaGas has a natural gas storage business that has been designated as a broker/trader business that purchases and sells natural gas on a back to back basis. AltaGas had the following contracts outstanding:

December 31, 2010			Notional volume (GJ)		
Derivative instruments	**Fixed price (per GJ)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Commodity forward	**$3.17 to $8.88**	**1–60**	**144,403,391**	**–**	**$ 63,112**
Commodity forward	**$3.17 to $9.85**	**1–60**	**–**	**142,085,340**	**$ (51,403)**

December 31, 2009			Notional volume (GJ)		
Derivative instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$4.55 to $10.01	1–61	127,863,433	–	$ 47,598
Commodity forward	$4.51 to $9.825	1–61	–	127,863,433	$ (40,808)

At December 31, 2010 the fair value of proprietary natural gas storage was $11,164,204 (2009 – nil). The change in fair value of proprietary natural gas inventory in storage in 2010 resulted in a net pre tax unrealized gain of $903,033 (2009 – nil).

NGL Frac Spread

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread. AltaGas had the following contracts outstanding:

December 31, 2010			Notional volume		
Product	**Fixed price**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Propane	**$1.049 to $1.150 US/gallon**	**1–24**	**46,452,000 gallons**	**–**	**$ (4,882)**
Butane	**$1.389 to $1.538 US/gallon**	**1–24**	**14,994,000 gallons**	**–**	**$ (2,062)**
WTI	**$85.67 to $93.95 US/Bbl**	**1–24**	**170,500 Bbls**	**–**	**$ (786)**
USD swaps	**$1.016 to $1.020**	**1–24**		**$ 28,763**	**$ 215**
Natural gas	**$3.65 to $5.42/GJ**	**1–24**	**–**	**6,968,345 GJ**	**$ (2,810)**

December 31, 2009			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$0.858 to $1.555 US/gallon	1–12	14,705,000 gallons	–	$ (347)
Butane	$1.100 to $1.870 US/gallon	1–12	4,726,000 gallons	–	$ (231)
WTI	$72.55 to $122.95 US/Bbl	1–12	80,700 Bbls	–	$ 749
USD swaps	$0.995 to $1.154	1–12		$ 38,890	$ 202
Natural gas	$4.79 to $8.88/GJ	1–12	–	3,270,600 GJ	$ (2,375)

Power

Under the PPAs AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Company sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2010 AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following commodity forward contracts on electrical power outstanding:

December 31, 2010				Notional volume (MWh)			
Derivative instruments		**Fixed price (per MWh)**	**Period (months)**	**Sales**	**Purchases**		**Fair value**
Commodity forward	**$**	**44.75 to $89.90**	**1–54**	**203,387**	**–**	**$**	**2,990**
Commodity forward	**$**	**46.00 to $70.35**	**1–24**	**–**	**203,387**	**$**	**(611)**

December 31, 2009				Notional volume (MWh)			
Derivative instruments		Fixed price (per MWh)	Period (months)	Sales	Purchases		Fair value
Commodity forward	$	45.00 to $72.35	1–37	47,349	–	$	2,335
Commodity forward	$	44.75 to $70.36	1–37	–	47,349	$	(1,597)

AltaGas has the following commodity swaps and collars outstanding:

December 31, 2010				Notional volume (MWh)			
Derivative instruments		**Fixed price (per MWh)**	**Period (months)**	**Sales**	**Purchases**		**Fair value**
Swaps and collars	**$**	**58.00 to $75.00**	**1–12**	**270,120**	**–**	**$**	**(951)**
Swaps and collars	**$**	**56.50**	**1–85**	**–**	**184,104**	**$**	**(153)**

December 31, 2009				Notional volume (MWh)			
Derivative instruments		Fixed price (per MWh)	Period (months)	Sales	Purchases		Fair value
Swaps and collars	$	46.75 to $81.00	1–12	1,098,336	–	$	30,118
Swaps and collars	$	56.50	1–97	–	210,384	$	(132)

AltaGas had the following heat rate hedges outstanding:

December 31, 2010				Notional volume (MWh)			
Derivative instruments		**Fixed price (per GJ or MWh)**	**Period (months)**	**Sales**	**Purchases**		**Fair value**
Natural gas	**$**	**3.64**	**1–3**	**–**	**144,000**	**$**	**7**
Power	**$**	**62.25**	**1–3**	**13,500**	**–**	**$**	**342**

December 31, 2009				Notional volume (MWh)			
Derivative instruments		Fixed price (per GJ or MWh)	Period (months)	Sales	Purchases		Fair value
Natural gas	$	5.123	1	–	74,400	$	18
Power	$	65.50 to $70.00	1	6,975	–	$	128

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, AltaGas enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. AltaGas' target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

AltaGas had the following interest rate swaps outstanding:

December 31, 2010	**Weighted average interest rate**	**Period (months)**	**Notional quantity**	**Fair value**
Swaps	**1.310%**	**1–14**	**$ 80,000**	**$ 199**

December 31, 2009	Weighted average interest rate	Period (months)	Notional quantity	Fair value
Swaps	2.756%	1–26	$ 185,000	$ (282)

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, AltaGas enters into foreign exchange forwards, swaps and options for U.S. dollars (USD).

AltaGas had the following contracts outstanding:

December 31, 2010	**Fixed price**	**Period (months)**	**Notional quantity**	**Fair value**
Swaps (USD)	**$1.0117 to $1.0887**	**1–23**	**$ 20,009**	**$ 217**

December 31, 2009	Fixed price	Period (months)	Notional quantity	Fair value
Swaps (USD)	$1.0164 to $1.2215	1–21	$ 16,900	$ 248

In 2009 AltaGas entered into a natural gas storage agreement denominated in U.S. dollars resulting in an embedded derivative. The change in value of the contract is recognized in unrealized gain on risk management. The unrealized gain was $87,057 as at December 31, 2009. The natural gas storage agreement was settled in 2010 and AltaGas had no embedded derivatives as at December 31, 2010.

Bond Forward

In April 2009 AltaGas issued $200 million of senior unsecured MTNs with a maturity date of April 2014. To partially hedge against the risk of rising interest rates, AltaGas entered into a $50 million bond forward contract with a Canadian chartered bank in December 2008, to lock in a five-year Government of Canada bond yield of approximately 3.28 percent. AltaGas settled the bond forward contract in April 2009, and the $3.4 million payment was recorded in other comprehensive income and is being amortized to interest expense over the term of the MTN, which expires in April 2014.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity, interest rate swap and foreign exchange contract outstanding, taking into consideration future income tax impact. The following table illustrates potential effects of changes in relevant risk variables on AltaGas' net income and OCI for contracts in place at December 31, 2010:

Factor share	Increase or decrease[1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	$1/MWh	$ 139	$ 198
Natural gas spot price (AECO)	$0.50/GJ	$ 1,544	–
NGL frac spread:			
Propane	$1/Bbl	$ 816	–
Butane	$1/Bbl	$ 263	–
WTI	$1/Bbl	$ 201	–
Natural gas to replace heat value of NGL	$0.50/GJ	$ 1,263	$ 1,286
Foreign exchange (USD only)	1%	$ 204	–
Interest rate swaps	25 bps	$ 187	–
Foreign exchange	1%	$ 147	–

1 Estimated increase or decrease to forward prices or curves.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas provides an allowance for doubtful accounts in the normal course of its business.

AltaGas' maximum credit exposure consists primarily of the carrying value of the non derivative financial assets and the fair value of derivative financial assets. At December 31, 2010 AltaGas had no concentration of credit risk with a single counterparty.

Accounts Receivable Past Due or Impaired

The Trust had the following past due and impaired receivables:

			Receivables by period and not impaired			
December 31, 2010 **Accounts receivable**	**2010**	**Receivables impaired**	**Less than 30 days**	**31–60 days**	**61–90 days**	**Over 90 days**
Trade receivable	**$ 213,788**	**$ 1,325**	**$ 199,692**	**$ 3,777**	**$ 1,987**	**$ 7,007**
Other receivable	**11,907**	**–**	**9,336**	**–**	**86**	**2,485**
Allowance for credit losses	**(1,325)**	**(1,325)**	**–**	**–**	**–**	**–**
	$ 224,370	**$ –**	**$ 209,028**	**$ 3,777**	**$ 2,073**	**$ 9,492**

Allowance for credit losses	
Allowance for credit losses, beginning of year	**$ 2,167**
New allowance	**150**
Allowance applied to uncollectible customer accounts	**(992)**
Allowance for credit losses, end of year	**$ 1,325**

			Receivables by period and not impaired			
December 31, 2009 **Accounts receivable**	2009	Receivables impaired	Less than 30 days	31–60 days	61–90 days	Over 90 days
Trade receivable	$ 191,797	$ 2,167	$ 170,572	$ 8,379	$ 2,841	$ 7,838
Other receivable	14,043	–	9,974	–	161	3,908
Allowance for credit losses	(2,167)	(2,167)	–	–	–	–
	$ 203,673	$ –	$ 180,546	$ 8,379	$ 3,002	$ 11,746

Allowance for credit losses	
Allowance for credit losses, beginning of year	$ 1,908
Impairment expense	259
Allowance for credit losses, end of year	$ 2,167

Liquidity Risk on Financial Instruments

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they fall due. AltaGas manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. AltaGas' objective is to maintain its investment grade ratings to ensure it has access to debt and equity funding as required.

At December 31, 2010 AltaGas had the following contractual maturities with respect to non derivative financial liabilities:

		Payments due by period			
December 31, 2010	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Short-term debt	$ 9,478	$ 9,478	$ –	$ –	$ –
Current portion of long-term debt	1,508	1,508	–	–	–
Long-term debt [1]	893,498	–	413,419	5,079	475,000
	$ 904,484	$ 10,986	$ 413,419	$ 5,079	$ 475,000

1 Comprising operating loans, MTNs and capital lease obligations excluding deferred financing costs (note 10).

16. SHAREHOLDERS' EQUITY

December 31	2010	2009
Common shares (note 17)	$ 1,023,033	$ 982,662
Preferred shares	194,126	–
Contributed surplus (note 11)	5,672	5,621
Accumulated earnings	916,307	815,045
Warrants	–	4,500
Accumulated dividends – common shares [1]	(95,253)	(41,114)
Accumulated dividends – preferred shares [2]	(4,038)	–
Accumulated unitholders' distributions declared [3]	(796,040)	(709,058)
Distributions of common shares of Utility Group	(29,848)	(29,848)
Transition adjustment resulting from adopting new financial instruments accounting standards	(176)	(176)
Accumulated other comprehensive income	(2,752)	21,225
	$ 1,211,031	$ 1,048,857

1 Accumulated common share dividends paid by AltaGas as at December 31, 2010 was $45.1 million (December 31, 2009 – $Nil).
2 Accumulated preferred share dividends paid by AltaGas as at December 31, 2010 was $4.0 million (December 31, 2009 – $Nil).
3 Accumulated unitholders' distributions paid by AltaGas operating as an income trust as at December 31, 2010 was $796.7 million (December 31, 2009 – $694.0 million), respectively.

17. SHAREHOLDERS' CAPITAL

Authorization

As at December 31, 2010, pursuant to the Arrangement, AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue preferred shares not to exceed 50 percent of the voting rights attached to the then issued and outstanding common shares.

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

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

Trust Units Issued and Outstanding	Number of units		Amount
December 31, 2009	78,231,948	$	968,519
Units issued for cash on exercise of options	39,500		738
Units issued under DRIP	1,099,747		18,928
Units issued for exchangeable units	2,009		59
Units issued on exercise of warrants [1]	180,433		3,394
Units cancelled pursuant to the Arrangement – July 1, 2010	(79,553,637)		(991,638)
December 31, 2010	–	$	–

Exchangeable Units Issued and Outstanding	Number of units		Amount
December 31, 2009 issued by AltaGas LP #1	2,083,656	$	14,143
AltaGas LP #1 units redeemed for Trust units	(2,009)		(59)
Units cancelled pursuant to the Arrangement – July 1, 2010	(2,081,647)		(14,084)
December 31, 2010	–		–
Issued and outstanding at December 31, 2010	–	$	–

1 On January 1, 2010 AltaGas issued 180,433 units on exercise of special warrants that were originally issued in February 2008 on a one-for-one basis at $24.94 per special warrant.

Common Shares Issued and Outstanding	Number of shares		Amount
December 31, 2009	–	$	–
Shares issued pursuant to the Arrangement – July 1, 2010	81,635,284		1,005,722
Shares issued for cash on exercise of options	197,250		4,177
Shares issued under DRIP	693,865		13,134
Issued and outstanding December 31, 2010	82,526,399	$	1,023,033

Weighted Average Shares Outstanding	2010	2009
Number of shares – basic	81,511,788	78,539,800
Dilutive equity instruments [1]	379,350	830,847
Number of shares – diluted	81,891,138	79,370,647

1 Includes options, convertible debentures and warrants

Preferred shares

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

Holders of the Series A Preferred Shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2015 (the Initial Period) at an annual rate of 5.00 percent, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payment of $0.4589 per Series A Preferred Share was paid 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. AltaGas may, at its option, redeem for cash all or any part of the outstanding Series A Preferred Shares by the payment of $25.00 per share plus all accrued and unpaid dividends.

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

Share option plan

The Company has an employee share option plan under which employees and directors are eligible to receive grants. At December 31, 2010, 3,102,653 shares outstanding were reserved for issuance under the plan. As at December 31, 2010, options granted under the plan generally had a term of 8 years until expiry and vested no longer than over a four-year period.

At December 31, 2010 outstanding options were exercisable at various dates within the next ten years. As at December 31, 2010 the unexpensed fair value of share option compensation cost associated with future periods was $3.0 million (December 31, 2009 – $0.7 million).

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

	Options outstanding					
	2010			2009		
	Number of options		Exercise price[1]	Number of options		Exercise price[1]
Share options outstanding, beginning of year	**3,807,250**	**$**	**19.86**	2,972,250	$	20.33
Granted	**1,568,500**		**20.26**	1,024,500		18.04
Exercised	**(236,750)**		**14.49**	(71,750)		12.94
Expired	**(280,500)**		**19.46**	(117,750)		20.30
Share options outstanding, end of year	**4,858,500**	**$**	**20.27**	3,807,250	$	19.86
Share options exercisable, end of year	**1,731,752**	**$**	**22.65**	1,194,398	$	23.48

1 Weighted average.

The following table summarizes the employee share option plan as at December 31, 2010:

	Options outstanding				Options exercisable		
	Number outstanding		Weighted average exercise price	Weighted average remaining contractual life	Number exercisable		Exercise price
$5.00 to $15.25	986,875	$	14.19	7.88	380,750	$	14.12
$15.26 to $25.08	3,128,375		20.42	8.85	668,502		22.16
$25.09 to $29.15	743,250		27.72	5.86	682,500		27.89
	4,858,500	$	20.27	8.20	1,731,752	$	22.65

The fair value of each option granted is estimated on the date of grant using the Black Scholes option pricing model with weighted average assumptions for grants as follows:

	2010	2009
Risk-free interest rate (%)	**3.25**	3.35
Expected life (years)	**10**	10
Expected volatility (%)	**24.78**	24.58
Annualized distribution per unit ($) average – issued under trust structure	**2.16**	2.15
Annualized dividend per share ($) average – issued under corporate structure	**1.32**	–

In 2004, AltaGas implemented an equity based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. The phantom shares are valued on dividends declared and the trading price of the Company's shares. The shares vest on a graded vesting schedule. The compensation expense recorded in 2010 in respect of this plan was $9.7 million (2009 – $7.2 million). As at December 31, 2010 the unexpensed fair value of equity based compensation costs associated with future periods was $15.6 million (December 31, 2009 – $26.4 million).

18. NET INCOME PER SHARE

The following table summarizes the computation of net income per unit:

Years ended December 31		2010		2009
Numerator:				
Numerator for basic net income applicable to common shares	$	97,224	$	141,309
Numerator for diluted net income applicable to common shares	$	97,224	$	141,998
Denominator:				
Weighted-average number of shares		81,512		78,540
Dilutive equity instruments [1]		379		831
Denominator for diluted net income applicable to common shares		81,891		79,371
Basic net income applicable to common shares	$	1.19	$	1.80
Diluted net income per share	$	1.19	$	1.79

1 Includes options and warrants.

19. COMMITMENTS

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment at December 31, 2010 are estimated as follows:

2011	$	5,316
2012		4,711
2013		3,903
2014		993
2015		344
	$	15,267

In 1999 AltaGas acquired an agreement to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 971 Mcf/d in 2010 (2009 – 841 Mcf/d).

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

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

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 December 31, 2010, AltaGas is obligated to pay approximately $92.5 million for construction work related to this project which is expected to be completed before mid-2014.

At December 31, 2010, AltaGas was committed to incur future capital expenditures for a variety of projects for an aggregate of approximately $20.7 million for materials and services that suppliers had not yet delivered to AltaGas.

20. NET CHANGE IN NON-CASH WORKING CAPITAL

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

Years ended December 31	2010[1]	2009[1]
Accounts receivable	$ (20,697)	$ 41,744
Inventory	(11,706)	(626)
Other current assets	1,285	200
Regulatory assets	2,565	(1,774)
Accounts payable and accrued liabilities	69,276	(75,057)
Customer deposits	(9,246)	6,661
Regulatory liabilities	91	–
Deferred revenue	–	(2,777)
Other current liabilities	(2,528)	(7,096)
	29,040	(38,725)
Add back:		
increase (decrease) in capital costs payable	(30,979)	20,996
Net change in non-cash working capital related to operations	$ (1,939)	$ (17,729)

1 Specific line items may not agree with the net change in the Consolidated Balance Sheets due to acquisition.

Total cost of sales recognized from sale of natural gas inventory in 2010 was $25.6 million (2009 – $6.8 million).

Amounts paid relating to interest expense and income taxes were as follows:

Years ended December 31	2010	2009
Interest paid	$ 46,078	$ 32,328
Income taxes paid (received)	$ 2,368	$ (89)

21. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $2.5 million for the year ended December 31, 2010 (2009 – $2.3 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine AltaGas employees for pre AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2010 and 2009 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2008 based upon a report dated April 29, 2009.

As at December 31, 2010 the accrued benefit obligation of AltaGas for this plan was $2.7 million (December 31, 2009 – $2.2 million). At December 31, 2010 the plan had an accrued benefit asset recognized in the Consolidated Financial Statements of $18,000 (December 31, 2009 – $3,000).

Plan contributions for the Younger pension plan and Harmattan pension plan during 2010 and 2009 were made in accordance with actuarial valuations for funding purposes as at December 31, 2006 and December 31, 2008, respectively. As at December 31, 2010 the accrued benefit obligation of AltaGas for these plans was $11.1 million (December 31, 2009 – $9.0 million). At December 31, 2010 these plans had an accrued benefit liability recognized in the Consolidated Financial Statements of $0.8 million (December 31, 2009 – $0.8 million).

In 2009 AltaGas assumed two defined benefit non contributory pension plans as a result of the acquisition of Utility Group (note 3). The plans are in relation to substantially all full-time employees of AUI. Plan contributions for the AUI pension plans during 2010 and 2009 were made in accordance with actuarial valuations for funding purposes as at September 30, 2008 based on reports dated April 15, 2009 for each plan. As at December 31, 2010 the accrued benefit obligation of AltaGas for these plans was $25.0 million (December 31, 2009 – $19.0 million). At December 31, 2010 the plans had accrued benefit liabilities recognized in the Consolidated Financial Statements of $1.5 million (December 31, 2008 – $1.4 million).

For the year ended December 31, 2010 the net pension cost for all defined benefit plans was $2.1 million (2009 – $0.8 million).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 AltaGas instituted a non-registered, defined benefit retirement plan that provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. In 2009, AltaGas assumed the liability recorded for the SERP held by Utility Group (note 3). As at December 31, 2010 the accrued benefit obligation of AltaGas for this plan was $9.1 million (December 31, 2009 – $6.4 million). At December 31, 2010 the plan had an accrued benefit liability recognized in the financial statements of $8.0 million (December 31, 2009 – $6.2 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

For the year ended December 31, 2010 the net pension expense related to the SERP was $2.0 million (2009 – $1.2 million).

Post-Retirement Benefits

In 2008 AltaGas assumed two post retirement benefit plans for the unionized employees at Younger and Harmattan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

In 2009 AltaGas assumed a post retirement benefit plan for certain employees of AUI providing benefits such as life insurance and health care. These other benefit plans are not funded.

For the year ended December 31, 2010 the net benefit cost for these plans was $0.3 million (2009 – $0.2 million).

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 7.83 percent and the ultimate trend rate is 4.50 percent, which is assumed to be achieved by 2029.

The following table summarizes the details of the defined benefit plans, including the SERP and post retirement plans:

	Defined benefit 2010	Post-retirement benefits 2010	Defined benefit 2009	Post-retirement benefits 2009
Accrued benefit obligation				
Balance, beginning of year	$ 36,611	$ 2,571	$ 13,146	$ 563
Assumed through acquisition [1]	–	–	16,910	1,217
Actuarial loss	6,553	131	3,673	617
Current service cost	3,104	129	2,261	93
Interest cost	2,538	177	2,249	136
Benefits paid	(789)	(62)	(1,628)	(55)
Balance, end of year	48,017	2,946	36,611	2,571
Plan assets				
Fair value, beginning of year	28,688	–	8,763	–
Assumed through acquisition [1]	–	–	14,542	–
Actual loss on plan assets	3,550	–	4,978	–
Employer contributions	2,366	62	2,280	55
Member contributions	99	–	95	–
Benefits paid	(789)	(62)	(1,628)	(55)
Expected plan expenses	(227)	–	(342)	–
Fair value, end of year	33,687	–	28,688	–
Funded deficit	(14,330)	(2,946)	(7,923)	(2,571)
Unamortized transitional obligation	131	151	179	181
Unamortized past service costs	548	–	625	–
Unamortized net actuarial loss	6,383	270	1,511	137
Accrued benefit liability recognized in the financial statements	$ (7,268)	$ (2,525)	$ (5,608)	$ (2,253)

1 Includes the AUI plan acquired in the acquisition of Utility Group (note 3) in 2009.

	Defined benefit 2010	Post-retirement benefits 2010	Defined benefit 2009	Post-retirement benefits 2009
Discount rate (%)	5.80–7.10	5.80–6.70	6.20–7.10	6.50–6.70
Expected long-term rate of return on plan assets (%)	0.00–6.75	0.00–6.75	0.00–7.75	0.00–6.75

Significant actuarial assumptions used as at December 31	**Defined benefit 2010**	**Post-retirement benefits 2010**	Defined benefit 2009	Post-retirement benefits 2009
Discount rate (%)	**5.80–7.10**	**5.80–6.70**	6.20–7.10	6.50–6.70
Expected long-term rate of return on plan assets (%)	**0.00–6.75**	**0.00–6.75**	0.00–7.75	0.00–6.75
Rate of compensation increase (%)	**0.00–5.50**	**4.00**	0.00–5.50	4.00
Average remaining service life of active employees (years)	**14.7**	**13.1**	14.8	10.1
Net benefit plan expense for the year				
Current service cost and expenses	**$ 3,264**	**$ 129**	$ 1,519	$ 43
Interest cost	**2,538**	**177**	1,262	62
Actual gain on plan assets	**(522)**	**–**	(2,362)	–
Actuarial loss on accrued benefit obligation	**27**	**–**	2,380	209
Costs arising in the year	**5,307**	**306**	2,799	314
Differences between costs arising in the year and costs recognized in the year in respect of:				
Actuarial (gain) loss on plan assets	**(1,400)**	**–**	1,498	–
Plan amendments	**–**	**–**	1	–
Actuarial gain on accrued benefit obligation	**(6)**	**(2)**	(2,414)	(231)
Amortization of past service costs	**77**	**–**	77	–
Transitional obligations	**48**	**30**	11	7
Net periodic benefit plan costs recognized	**$ 4,026**	**$ 334**	$ 1,972	$ 90

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 December 31, 2010:

	Percentage of plan assets
Cash and short-term equivalents	4.05%
Canadian equities	33.93%
Foreign equities	27.85%
Fixed income	34.17%
	100.00%

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care trend rates would have the following effects for 2010:

	Increase	Decrease
Service and interest costs	$ 45	$ (35)
Accrued benefit obligation	$ 474	$ (381)

AltaGas pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by certain employees of AltaGas. Payments of approximately $0.1 million were made in 2010 (2009 – approximately $0.1 million) which is the exchange value of the property agreed to by both parties. The lease expires December 2011. The transactions were in the normal course of business and were recorded at their exchange amounts.

Prior to acquisition of Utility Group, AltaGas held significant influence over Utility Group given AltaGas' 19.8 percent ownership, and AltaGas' Chairman and Chief Executive Officer was a director of Utility Group. AltaGas sold natural gas to Utility Group and received management fees from Utility Group for operating services provided. These transactions were part of the normal course of business and were recorded at their exchange amounts. Commencing from October 8, 2009, the date that AltaGas owned 100 percent of the shares of Utility Group, all the transactions between AltaGas and Utility Group were eliminated in the consolidated financial statements.

23. JOINT VENTURES

AltaGas' proportionate interest in its joint venture arrangements is summarized in the table below:

	2010	2009
Proportionate share of operating income for the years ended December 31		
Revenues	$ 250,900	$ 238,176
Expenses	195,250	193,807
	$ 55,650	$ 44,369
Proportionate share of net assets at December 31		
Current assets	$ 59,731	$ 31,304
Capital assets	295,900	299,213
Energy services arrangements, contracts and relationships	77,538	82,284
Long-term investments and other assets	2	14
Current liabilities	(25,644)	(15,644)
Other long-term liabilities	(4,579)	(1,660)
	$ 402,948	$ 395,511
Proportionate share of cash flows for years ended December 31		
Operating activities	$ 67,877	$ 61,613
Investing activities	(10,117)	(18,497)
Financing activities	(43,376)	(38,309)
	$ 14,384	$ 4,807

24. NON-MONETARY TRANSACTION

In 2009 AltaGas entered into a non-monetary transaction with a third-party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The B.C. RECs were created through the generation of power at the Bear Mountain Wind Park in 2009 and 2010. The verified emission offsets received by AltaGas were used to offset the costs to comply with Specified Gas Emitters Regulation (SGER) for the 2008 compliance year. The contract was completed in the second quarter 2010.

25. 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. If the operator was successful in its claim, the impact to income has been estimated to be approximately $13 million.

26. COMPARATIVE FIGURES

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

27. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities and the remainder is at the exchange amount. In accordance with the CICA Handbook Section 1700, in the year ended December 31, 2010, AltaGas changed the composition of its reportable segments as a result of modifications and growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Company'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 sale of natural gas and electricity • natural gas storage facilities
Power	• coal-fired and gas-fired power output under PPAs and other agreements • gas-fired power plants • wind and run-of-river power plants • sale of power to commercial and industrial users in Alberta
Utility	• regulated natural gas distribution assets
Corporate	• the costs 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:

Year ended December 31, 2010	Gas[2]	Power[2]	Utility	Corporate	Intersegment Elimination	Total
Revenue	$1,064,297	$ 261,563	$ 151,697	$ 2,962	$ (125,130)	$1,355,389
Unrealized loss on risk management	–	–	–	(1,337)	–	(1,337)
Cost of sales	(751,647)	(159,719)	(79,768)	–	122,580	(868,554)
Operating and administrative	(154,823)	(10,044)	(35,494)	(43,729)	2,550	(241,540)
Accretion of asset retirement obligations	(2,839)	(33)	(8)	–	–	(2,880)
Amortization	(59,072)	(15,332)	(11,648)	(3,128)	–	(89,180)
Foreign exchange loss	–	–	–	(67)	–	(67)
Interest expense	–	–	(7,723)	(41,119)	–	(48,842)
Income (loss) before income taxes	$ 95,916	$ 76,435	$ 17,056	$ (86,418)	$ –	$ 102,989
Net additions to						
Capital assets[1]	$ 108,221	$ 51,375	$ 54,687	$ 5,838	$ –	$ 220,121
Energy service arrangements contracts and relationships	–	1,863	–	–		1,863
Long-term investment and other assets[1]	–	(54)	(1,890)	3,794	–	1,850
Goodwill	$ 143,726	$ –	$ 55,771	$ –	$ –	$ 199,497
Segmented assets	$1,712,141	$ 466,341	$ 475,968	$ 97,242	$ –	$2,751,692

1 Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.
2 Commencing January 1, 2010 the Commercial and Industrial power retail business was transferred from the Gas reporting segment to the Power reporting segment without restatement of earlier periods.

Year ended December 31, 2009	Gas	Power	Utility	Corporate	Intersegment Elimination	Total
Revenue	$ 1,098,873	$ 188,508	$ 43,538	$ 14,919	$ (81,270)	$ 1,264,568
Unrealized gain on risk management	–	–	–	3,697	–	3,697
Cost of sales	(771,749)	(86,280)	(30,513)	–	76,854	(811,688)
Operating and administrative	(159,886)	(6,059)	(3,419)	(40,133)	4,416	(205,081)
Accretion of asset retirement obligations	(3,127)	(10)	(1)	–	–	(3,138)
Amortization	(61,274)	(8,167)	(2,153)	(2,527)	–	(74,121)
Foreign exchange loss	–	–	–	(1)	–	(1)
Interest expense	–	–	(1,036)	(30,723)	–	(31,759)
Income (loss) before income taxes	$ 102,837	$ 87,992	$ 6,416	$ (54,768)	$ –	$ 142,477
Net additions to						
Capital assets [1]	$ 52,406	$ 159,544	$ 271,373	$ 3,073	$ –	$ 486,396
Long-term investment and other assets [1]	–	(367)	(12,300)	24,410	–	11,743
Goodwill	$ 143,691	$ –	$ 58,037	$ –	$ –	$ 201,728
Segmented assets	$ 1,623,120	$ 425,899	$ 430,057	$ 149,865	$ –	$ 2,628,941

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

SHAREHOLDER INFORMATION

2010 Dividend and Distribution History

Ex-Distribution Date	Record Date	Payment Date	Amount
January 21, 2010	January 25, 2010	February 16, 2010	$0.18
February 23, 2010	February 25, 2010	March 15, 2010	$0.18
March 23, 2010	March 25, 2010	April 15, 2010	$0.18
April 22, 2010	April 26, 2010	May 17, 2010	$0.18
May 20, 2010	May 25, 2010	June 15, 2010	$0.18
June 23, 2010	June 25, 2010	June 30, 2010	$0.18
July 22, 2010	July 26, 2010	August 16, 2010	$0.11
August 23, 2010	August 25, 2010	September 15, 2010	$0.11
September 23, 2010	September 27, 2010	October 15, 2010	$0.11
October 21, 2010	October 25, 2010	November 15, 2010	$0.11
November 23, 2010	November 25, 2010	December 15, 2010	$0.11
December 23, 2010	December 29, 2010	January 17, 2011	$0.11
Total 2010 Cash Dividends & Distribution Declared:			$1.74

Dividend Reinvestment and Optional Common Share Purchase Plan of AltaGas Ltd. for Holders of Common Shares

AltaGas offers a Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP") for holders of common shares of AltaGas Ltd.

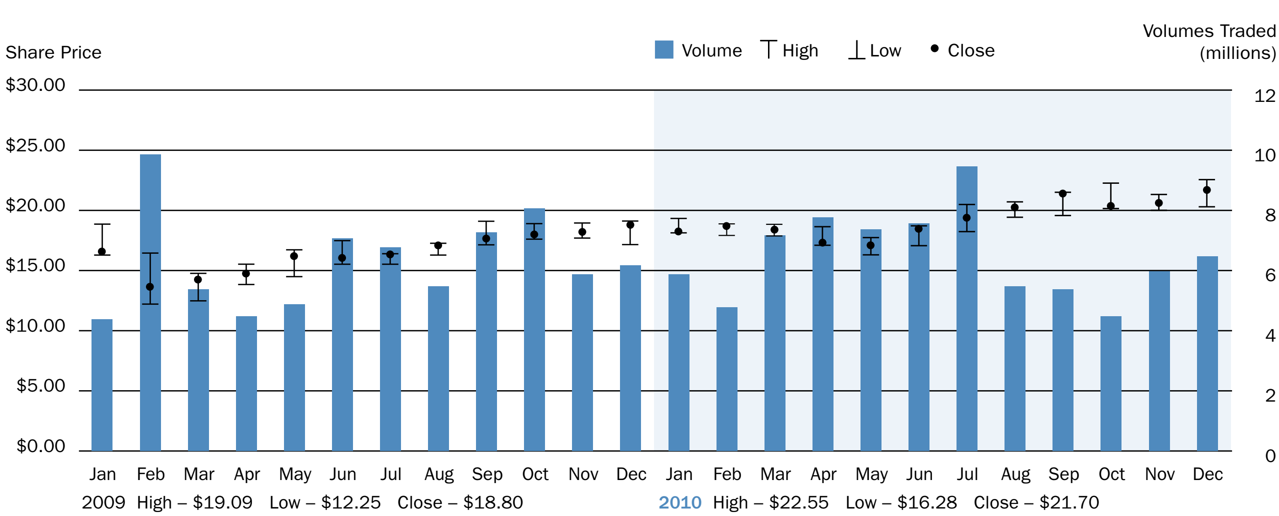
The DRIP provides eligible shareholders with the opportunity to:

- Reinvest cash dividends paid by AltaGas Ltd. into common shares of AltaGas Ltd. at a 5 percent discount to the average market price, under the dividend reinvestment component of the DRIP; and
- Purchase common shares of AltaGas Ltd. at the average market price (with no discount) under the optional common share purchase component of the DRIP, if the eligible shareholder is enrolled in the dividend reinvestment component of the DRIP.

Registered shareholders who are eligible and wish to participate in the DRIP must enroll directly with Computershare Trust Company of Canada, while beneficial shareholders who are eligible and wish to participate in the DRIP should contact their broker, investment dealer, financial institution or other nominee that holds their shares, in order to enroll.

Complete details on the DRIP are available on the AltaGas website at www.altagas.ca.

AltaGas Share Price and Volume (ALA)



10–YEAR REVIEW OF FINANCIAL AND OPERATING INFORMATION

($ millions unless otherwise indicated)		2010	2009	2008
Financial Highlights				
Income Statement	Revenue	1,354.1	1,268.3	1,816.8
	Net revenue [1]	485.5	456.6	476.5
	EBITDA [1]	243.8	251.5	258.7
	Operating income			
	Gas	95.9	102.9	103.6
	Power	76.4	88.0	117.9
	Utility	24.8	7.4	–
	Corporate	(45.3)	(24.0)	(33.5)
		151.8	174.3	188.0
	Net income	97.2	141.3	163.6
	Net income per basic share	$ 1.19	$ 1.80	$ 2.38
	EBITDA per basic share [1]	$ 2.99	$ 3.20	$ 3.76
Cash Flow	Funds from operations [1]	195.0	202.3	216.8
	Funds from operations per basic share [1]	$ 2.39	$ 2.58	$ 3.15
	Distributions/dividends per share declared	$ 1.74	$ 2.16	$ 2.125
Balance Sheet	Capital assets	1,995.6	1,857.1	1,436.7
	Energy service arrangements, contracts and relationships	120.8	128.9	138.9
	Total assets	2,751.7	2,628.9	2,132.3
	Short-term debt	9.5	14.5	4.5
	Long-term debt	895.0	1,000.1	560.8
	Shareholders' equity	1,211.0	1,048.9	957.4
Share Data (millions)	Shares outstanding at year-end	82.5	80.3	71.9
	Weighted average shares outstanding for the year (basic)	81.5	78.5	68.8
Ratios (%)	Return on average equity	9.44	13.6	19.6
	Return on average invested capital	8.23	10.0	13.6
	Debt as a percentage of total capitalization	42.8	49.2	37.8
Operating Statistics				
Gas	Extraction inlet capacity (Mmcf/d) [2]	1,594	1,594	1,594
	Extraction ethane volumes (Bbls/d) [3]	25,453	26,817	24,795
	Extraction NGL volumes (Bbls/d) [3]	12,654	13,236	12,242
	Total extraction volumes (Bbls/d) [3]	38,107	40,053	37,037
	Frac spread – realized ($/Bbl) [3, 4]	27.27	23.46	26.97
	Frac spread – average spot price ($/Bbl) [3, 4]	31.95	19.51	28.79
	Transmission volumes (Mmcf/d) [3, 5]	286	324	379
	Field processing throughput (gross Mmcf/d) [3]	423	453	541
	Field processing capacity utilization (%) [2]	35	39	46
	Average gas volumes marketed (GJ/d) [3, 8]	386,004	354,513	302,392
Power	Volume of power sold (GWh) [3]	2,828	2,725	2,623
	Price received on the sale of power ($/MWh) [3]	66.79	68.97	84.51
	Alberta Power Pool price ($/MWh) [3]	50.76	47.84	89.95
Utility	Natural gas deliveries – end-use (PJ) [6]	19.9	6.6	–
	Natural gas deliveries – transportation (PJ) [6]	5.3	0.6	–
	Service sites [2]	74,664	72,717	–
	Degree day variance (%) [7]			
	AUI	(1.6)	9.9	–
	Heritage	(13.2)	(1.0)	–

1. Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of the MD&A. 2. As at December 31. 3. Annual average. 4. Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price. 5. Excludes NGL pipeline volumes.

2007	2006	2005	2004	2003	2002	2001
1,428.4	1,362.6	1,502.3	864.6	710.6	492.7	489.8
324.0	318.9	296.9	250.4	217.3	169.9	135.0
175.2	174.5	156.8	134.5	122.8	95.6	69.9
59.3	63.4	60.1	47.9	43.3	25.0	35.2
94.6	90.9	48.7	35.8	31.6	26.1	–
–	–	6.2	7.9	8.7	8.8	8.2
(27.3)	(27.6)	(6.9)	–	–	–	–
126.6	126.7	108.1	91.6	83.6	59.9	43.4
108.8	114.5	90.3	65.8	38.3	29.4	19.2
$ 1.90	$ 2.06	$ 1.67	$ 1.33	$ 0.84	$ 0.70	$ 0.50
$ 3.05	$ 3.14	$ 2.90	$ 2.72	$ 2.70	$ 2.26	$ 1.83
162.9	161.7	129.0	108.6	90.2	70.8	50.2
$ 2.84	$ 2.92	$ 2.39	$ 2.20	$ 1.98	$ 1.67	$ 1.31
$ 2.065	$ 1.995	$ 1.85	$ 1.31	$ 0.38	$ 0.28	$ 0.18
682.3	677.9	645.4	746.7	677.9	663.4	521.0
95.7	103.3	110.9	113.1	101.0	107.0	112.2
1,172.7	1,109.6	1,068.3	1,108.6	919.3	904.9	721.1
3.6	–	2.7	7.0	4.5	50.6	100.0
217.2	265.5	266.3	352.5	392.4	368.9	283.9
584.7	529.4	478.6	483.5	363.3	338.6	261.9
58.1	56.4	54.6	53.2	45.7	45.2	38.5
57.4	55.5	54.0	49.4	45.5	42.3	38.2
19.8	22.7	18.4	15.7	10.9	9.8	7.3
16.2	16.3	13.0	11.6	11.1	9.3	8.7
27.4	33.4	36.0	42.6	52.2	55.3	58.5
554	554	539	539	349	349	219
13,355	13,132	13,155	8,602	4,056	1,425	1,063
6,752	6,564	6,202	4,834	3,519	1,974	1,555
20,108	19,696	19,357	13,436	7,575	3,399	2,618
21.38	18.47	9.31	10.51	6.23	6.35	–
22.48	18.47	9.31	10.51	6.23	6.35	–
407	400	432	432	403	106	47
527	555	563	560	520	492	489
52	54	60	61	61	63	65
388,217	327,057	312,272	174,337	–	–	–
2,661	2,878	3,466	3,481	3,266	2,669	–
68.59	69.26	54.59	48.77	47.56	41.27	–
66.84	80.48	70.19	54.54	62.98	43.85	–
–	–	10.5	14.0	14.7	14.7	13.7
–	–	9.5	11.6	10.5	8.4	8.4
–	–	61,447	60,430	59,543	58,499	57,542
–	–	(1.4)	2.6	6.9	7.8	(3.4)
–	–	(5.7)	2.3	–	–	–

6. 2009 deliveries reflect Utility Group deliveries as of October 8, 2009 when the Company obtained control and 100 percent of Heritage Gas deliveries as of November 18, 2009. Excludes Inuvik Gas Ltd. for all periods; excludes Heritage Gas Limited for all periods prior to 2009. 7. Variance from 20-year average – positive variances are favourable; 2009 statistics for partial year of ownership; Heritage 2004 and 2005 statistics based on variance to 30-year average. 8. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

CORPORATE INFORMATION

Management Team

David W. Cornhill
Chairman and Chief Executive Officer

Gregory A. Aarssen
Co-President – Gas

Richard M. Alexander
President and Chief Operating Officer

Dennis A. Dawson
Vice President General Counsel
and Corporate Secretary

Patricia M. Newson
President – AltaGas Utility Group Inc.

Deborah S. Stein
Vice President Finance and
Chief Financial Officer

Randy W. Toone
Co-President – Gas

David R. Wright
Executive Vice President Strategy
and Corporate Development

Auditors

Ernst & Young LLP
Calgary, Alberta, Canada

Transfer Agent

Computershare Trust Company
of Canada
Calgary, Alberta, Canada

Toll-free: 1-800-564-6253
Email: service@computershare.com

Investors are encouraged to contact Computershare for information concerning their security holdings.

Stock Exchange Listing

Toronto Stock Exchange: ALA

Annual Meeting

The annual meeting will be held at
3:00 p.m. MDT on
Wednesday, April 20, 2011 at
The Petroleum Club
319 – 5th Avenue S.W.,
Calgary, Alberta

Investor Relations

For investor relations enquiries, please contact:

Tel:	403-691-7100
Toll-free:	1-877-691-7199
Fax:	403-691-7150
Email:	investor.relations@altagas.ca

Definitions

Bbls/d	barrels per day
Bcf	billion cubic feet
bps	basis points
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
t/MWh	tonnes per megawatt-hour

Design and production Karo Group
Photography Colin Way
Printed in Canada by McAra

The paper selection preserves 39 trees,
saves 16,516 gallons of wastewater flow and
conserves 27,540,000 BTUs of energy.

FPO

FPO

1700, 355 - 4th Avenue SW
Calgary, Alberta T2P 0J1

altagas.ca

AltaGas Annual Report | 2010